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Improving flow-based market coupling by integrating redispatch potential - Evidence from a large-scale model

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Improving flow-based market coupling by integrating redispatch potential—Evidence from a large-scale model by Michael Bucksteeg, Simon Voswinkel and Gerald Blumberg

Abstract

Power markets have been gradually integrated to achieve the target of a single European market. A major step was the introduction of the flow-based market coupling (FBMC) in Central Western and Eastern Europe (Core region). FBMC reflects the physical constraints of the underlying transmission grid in detail. However, the European Commission and regulators imposed minimum margins to increase cross-border trade and to foster price convergence between the different bidding zones, neglecting physical constraints and increasing redispatch volumes. Integrating redispatch potentials into FBMC allows for moving closer to physical reality while maintaining a high level of cross-border trade. In this study, we develop a multi-stage model covering capacity calculation, market coupling, and redispatch stages. This study is the first to evaluate different options for integrating FBMC and redispatch potentials based on a large-scale numerical analysis of Central Europe. The results reveal that minimum margins effectively increase cross-border trade. However, this comes at a high cost due to additional redispatch needs, which reduce overall welfare. Integrating redispatch potentials in the market-clearing stage leads to a more efficient increase in cross-border capacities and elevates welfare. In the case of combining both approaches, the analysis indicates improved welfare of roughly 80 M€ per year.

Keywords: Flow-based market coupling, European electricity market, cross-border trade, congestion management, redispatch

JEL-Classification: Q4

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1 Introduction

In European electricity markets, the allocation of transmission capacity is based on a zonal pricing approach with redispatch (Bjørndal and Jornsten 2001). The zonal markets have been gradually integrated to achieve the target of a single European market. A major step toward the target model was the introduction of the so-called flow-based market coupling (FBMC) (ACER 2019; European Parliament 2019). Compared to the former bilateral net transfer capacity (NTC) method, the FBMC approach entails an improved representation of physical limitations in the transmission grid. It allows the allocation of transmission capacity to the most efficient trades between market zones. Since its launch in Central Western Europe in 2015, FBMC has increased cross-zonal trading capacities in the region (Schönheit et al. 2021b). Consequently, the integration of zonal markets and welfare could be enhanced even though welfare gains remained below expectations (Kristiansen 2020; Lang et al. 2020).

Although some studies have addressed the benefits of nodal pricing in Europe (Neuhoff et al. 2013; Bjørndal et al. 2018; Bjørndal et al. 2014), its introduction has failed mainly due to political reservations (Antonopoulos et al. 2020). Consequently, the debate focuses on further developing the zonal market design. In zonal markets, the delimitation of market zones is essential for efficiency and effectiveness in managing grid congestion. A large body of research deals with adequate bidding zone configurations and related impacts on electricity markets and congestion management (Trepper et al. 2015; Egerer et al. 2016; Felling and Weber 2018; Deilen et al. 2019; Felling 2019; Felling et al. 2023). Further contributions extend this by studying the long-term effects and risks of changing zonal configurations (Grimm et al. 2016; Bertsch et al. 2017; Deilen et al. 2019). Zonal markets with imperfect bidding zone configurations drive the need for redispatch measures to maintain stable grid operation. Moreover, the extension of fluctuating renewable energy sources, such as wind and solar energy, has led to a considerable increase in redispatch volumes and costs (ACER and CEER 2021). This development has stimulated further debate about optimizing redispatch procedures (Kunz and Zerrahn 2015; Zerrahn and Kunz 2016) and market-based redispatch (Hirth and Schlecht 2020; Grimm et al. 2018; Bjørndal et al. 2017; Grimm et al. 2022; Martin et al. 2022).

Despite the advancement of zonal market coupling through the FBMC approach, regulators had concerns about the level of commercial cross-border exchanges, which remained below expectations (CREG 2017; ACER and CEER 2021). While combining a zonal approach with an improved representation of physical constraints is (on average) beneficial in terms of welfare and system security, it implies that not only cross-zonal but also internal transmission lines may limit cross-border trade. In this context, the FBMC method includes several specifications and parameters, such as the selection of critical network elements (CNEs), generation shift keys (GSKs), reliability margins, and adjustment values,

leading to imperfections and affecting the capacities allocated to the market (Marien et al. 2013; van den Bergh et al. 2016; Schönheit et al. 2020; Felten et al. 2021).

Consequently, minimum margins (or trading capacities) were introduced to increase cross-border exchanges (Henneaux et al. 2021; Schönheit et al. 2021a). Accordingly, trading capacities were raised to a minimum, possibly violating underlying physical transmission constraints. At the same time, transmission system operators (TSOs) have contemplated integrating costly remedial actions (i.e., redispatch) into the market-clearing algorithm to increase the capacity domain given to the market (Elia Group 2019). The basic idea is that if a network element limited cross-border exchange, redispatch measures or bids would be considered to increase the available margin on this line during the market clearing. Combining FBMC and redispatch, recent studies have analyzed different options to increase cross-border exchanges (Elia Group 2019; Poplavskeya et al. 2020; Schlecht and Hirth 2021). Hirth and Schlecht (2020), Schlecht and Hirth (2021), and Ehrhart et al. (2022) noted that these market-based redispatch mechanisms may be subject to strategic bidding behavior—that is, inc-dec gaming—which remains the main argument against this market design option. However, Schlecht and Hirth (2021) also discussed an approach in which the TSO is responsible for determining the available redispatch potential and providing the corresponding parameters to the market-clearing algorithm (i.e., the mandatory redispatch potential based on costs).¹

While this TSO-based approach avoids the inc-dec gaming issue and could be implemented at short notice, an in-depth analysis of related design options and their effects on electricity markets and grid operation is still pending. This study fills this gap and contributes to the existing literature in four respects. First, an extended FBMC problem that includes the redispatch potential is formulated. Second, three potential design options for determining the available redispatch units (incorporated in the market-clearing problem) are proposed. Third, the effects of the minimum remaining available margins (minRAMs) and the integration of redispatch potentials on welfare and system security are studied using a large-scale model covering Central Western and Eastern Europe (i.e., Core capacity calculation region). Fourth, we discuss the implications of introducing the analyzed design options, which can guide policymakers and regulators.

The remainder of this paper is organized as follows. In section 2, the general approach of this paper is presented. This includes an overview of the procedure for modeling FBMC in the current capacity calculation and allocation and operational redispatch planning processes implemented in the Core region. Moreover, the general effects of integrating the redispatch potential are discussed. In section 3, the

¹ However, market-based redispatch mechanisms may still be necessary in the future to integrate load-based flexibilities (including storages) if costs cannot be derived appropriately. Yet, these flexibilities may contribute to an efficient redispatch regime and account for a potential lack of positive redispatch potential in the future. Different design options are currently under discussion (Blumberg et al. 2022; Heilmann et al. 2022).

methods are introduced. First, the modeling of FBMC, including capacity calculation and redispatch optimization, is described. Second, the procedures and design options for integrating redispatch are proposed. The results of the proposed methodology are discussed in section 4. Finally, we draw the main conclusions and discuss the implications for policymakers.

2 Flow-based market coupling and redispatch potential

In zonal electricity markets, sufficient cross-zonal trading capacity is essential for creating welfare and synergies regarding system security. FBMC involves several actors and processes that will be briefly introduced in the following. Based on this introduction, the integration of redispatch potentials into the market-clearing algorithm and the underlying intentions are described. The setup of this study is based on the sequence of the day-ahead capacity calculation process for the Core region, the subsequent market coupling process, and the operational procedures for securing the grid (ACER 2019).

TSOs are responsible for the capacity calculation starting two days ahead of delivery. As shown in Figure 1, the capacity calculation is based on a grid model and forecasts regarding generation and load. The outputs of the capacity calculation are the trading capacities. In the case of FBMC, these commercial transaction constraints are represented by the remaining available margins (RAMs) of selected critical network elements (CNEs). The set of CNEs should contain the grid elements most affected by cross-zonal trade, helping to monitor the flows and sending more accurate congestion signals (Kristiansen 2020). Moreover, generation shift keys and zonal sensitivities (i.e. power transfer distribution factors, PTDFs) are determined that translate changes in the net position (i.e., net import or export) of a market zone into a shift in the power flow on a CNE. In other words, the physical constraints of the transmission grid limiting power flows between market zones are translated into commercial transaction constraints given to the market operators responsible for the subsequent market coupling (ACER 2019).

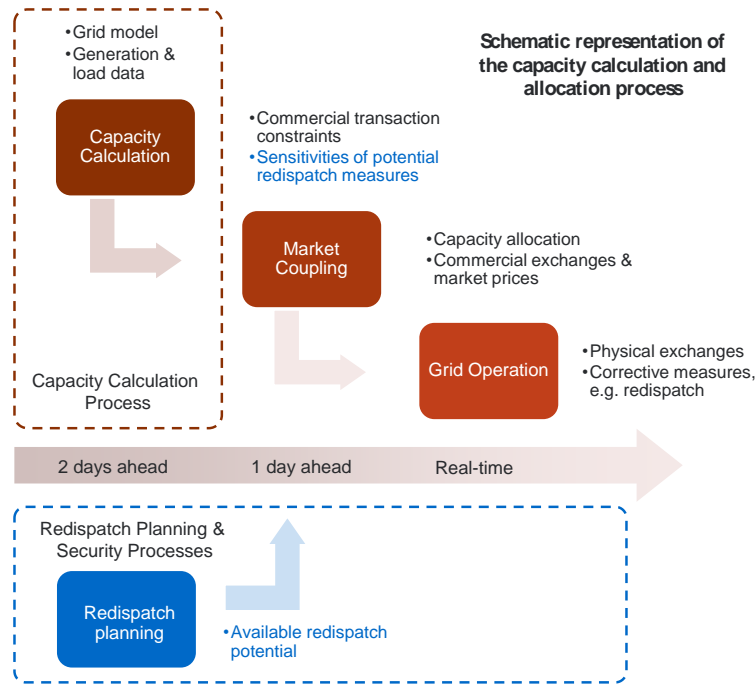


Figure 1: Schematic representation of the flow-based capacity calculation and allocation process

The market-clearing algorithm is executed by the market operators using the constraints submitted by the TSOs and based on the market participants' bids one day before delivery. With the objective of maximizing welfare, the scarce transmission capacity (of the considered CNEs) is allocated to the most efficient trades between all relevant market zones. The market-clearing algorithm delivers commercial exchanges (i.e., net positions) and market-clearing prices for each market zone. For the subsequent grid operation, TSOs must translate the commercial exchanges back into physical ones. Due to the zonal approximation of the FBMC, the market results may violate physical constraints requiring corrective measures, such as redispatch, to maintain stable grid operation. This involves (cross-border) redispatch planning and security processes to guarantee the real-time availability of redispatch units, which are carried out in parallel with the capacity calculation and allocation process (see also Figure 1) (ACER 2019).

Figure 2 depicts a schematic representation of a flow-based domain for a two-zone example and reveals the main motivation for integrating the redispatch potential into the market-clearing algorithm. In the initial situation, the import to market zone B is limited by a CNE (see Net Import B1 and the dashed red line in situation 1). A limitation of CNEs results from technical parameters and the system state and is expressed via the RAM (and zonal PTDFs). For instance, a system state associated with a high wind infeed within a market zone may induce a power flow on the CNE, reducing its RAM and cross-zonal exchange capabilities remaining for the day-ahead market coupling. Accordingly, relaxing the power flow on the CNE increases its RAM and cross-zonal exchange capabilities. In Figure 2, this is indicated by the shift of the limiting CNE, allowing a higher import to zone B (see Net Import B2 and the solid red line in situation 2).

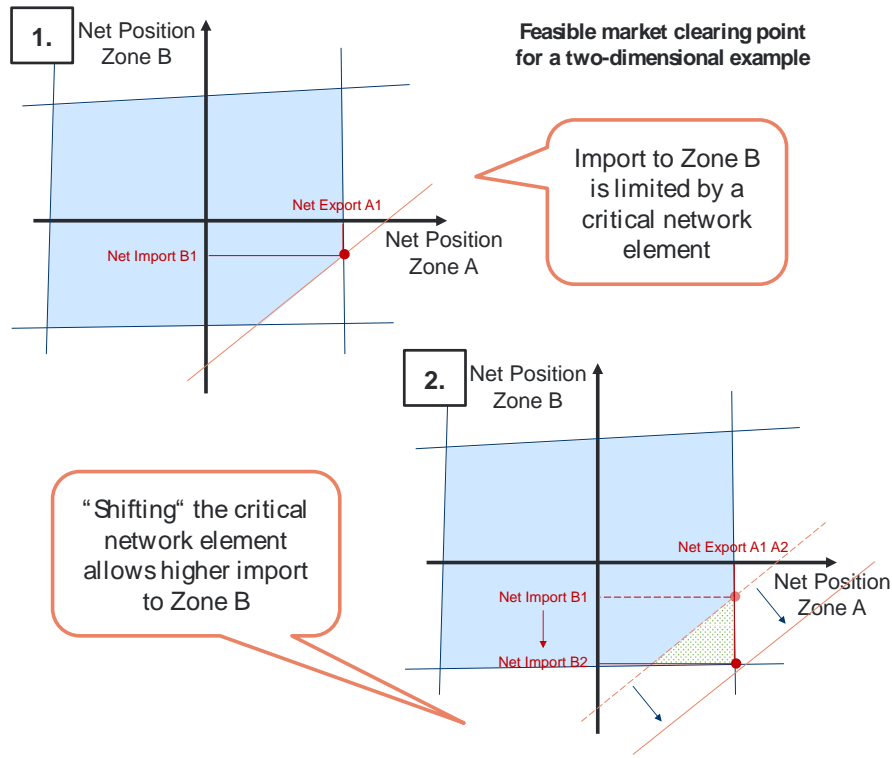


Figure 2: Schematic representation of a flow-based domain for a two-zone example

Suppose that the CNE is an internal grid element almost fully utilized during the capacity calculation. In this case, the internal CNE would limit cross-zonal trade, which should not occur according to the targets of Regulation (EU) 2019/943 (European Parliament 2019). In the long- and mid-term, grid expansion or a reconfiguration of bidding zones would be suitable measures to address this issue (Bertsch et al. 2017; Felling and Weber 2018; Felling et al. 2023). In the short term, a TSO may use remedial actions to reduce the utilization of the CNE during the capacity calculation. However, two problems arise related to costly remedial actions (i.e., redispatch). First, considering redispatch during the capacity calculation involves the instruction and activation of the affected redispatch units representing a market intervention by the TSO. Second, the TSO needs to know the market-clearing point, which is subject to uncertainty (e.g., forecast errors) one day before the market clearing, giving rise to inefficiencies.

Integrating the redispatch potential into the market-clearing algorithm helps overcome both issues. The EUPHEMIA algorithm was developed to solve the day-ahead market coupling problem (N-SIDE 2023). It delivers the market-clearing prices and net positions at the bidding zonal level. To include the redispatch potential, TSOs determine the available redispatch units (called the “redispatch potential”) during the capacity calculation process and provide the market operators with the required information. These include the location, available capacity, and activation costs of redispatch units and their sensitivity regarding the power flow on CNEs. If a CNE limits the cross-zonal exchange, the adjusted market-clearing algorithm may utilize the redispatch potential to make available additional capacity

for this purpose. Due to the simultaneous optimization of market bids, cross-zonal trading capacities, and the redispatch potential, redispatch will only be used when efficient. This applies if the additional costs for utilizing the redispatch potential are smaller than (or equal to) the welfare gain due to additional cross-zonal exchange.

Integrating redispatch into the market-clearing algorithm requires amendments to the existing processes, as marked in blue in Figure 1. However, the focus of this contribution is to extend the market-coupling problem and to determine the redispatch potential, as described in the following section.

3 Methods

3.1 Modeling flow-based market coupling

Comprehensive modeling of the European electricity market is essential to understanding the effects of integrating the redispatch potential into the market mechanism. The central pillar of European integrated electricity markets is FBMC, as outlined in section 1. The following sections describe the calculation of the flow-based parameters and the zonal market outcome (section 3.1.1), the extension of the market coupling problem by integrating the redispatch potential (section 3.1.2), and the redispatch problem that guarantees secure grid operation (section 3.1.3).

3.1.1 Basic model

We extend the model developed by Voswinkel et al. (2019) and include the determination of the flow-based parameters, zonal market clearing, and the optimization of redispatch. The upper part of *Figure 3* details the steps taken in the model.

The calculations are based on a grid model that covers most of the Core capacity calculation region (Core CCR)² and Switzerland. The model comprises around 2500 nodes and over 4000 extra-high-voltage (transmission) grid lines. Generation and demand assets may be located at each node.

The determination of flow-based parameters is based on the expected market outcome. This approximation is also called the base case. As the market result depends on flow-based parameters, we first performed an initial nodal optimal power flow and calculated provisional flow-based parameters using the market results of this nodal optimal power flow. These provisional flow-based parameters were then used to perform a zonal market clearing, which approximates the zonal market results mentioned above. The flow-based parameters were determined based on this approximation. Next, they were used to simulate the day-ahead market, another zonal calculation in which the capacity is allocated and the market is cleared. This resulted in the scheduled generation, commercial exchanges, and mar-

² Austria, Belgium, Czech Republic, France, Germany, Luxembourg, Netherlands, Poland, Slovakia, Slovenia,.

ket-clearing prices. The last step involved translating the commercial exchanges into physical exchanges via the known nodal positions of the scheduled generators and optimizing the redispatch to ensure a stable grid state without overloaded network elements.

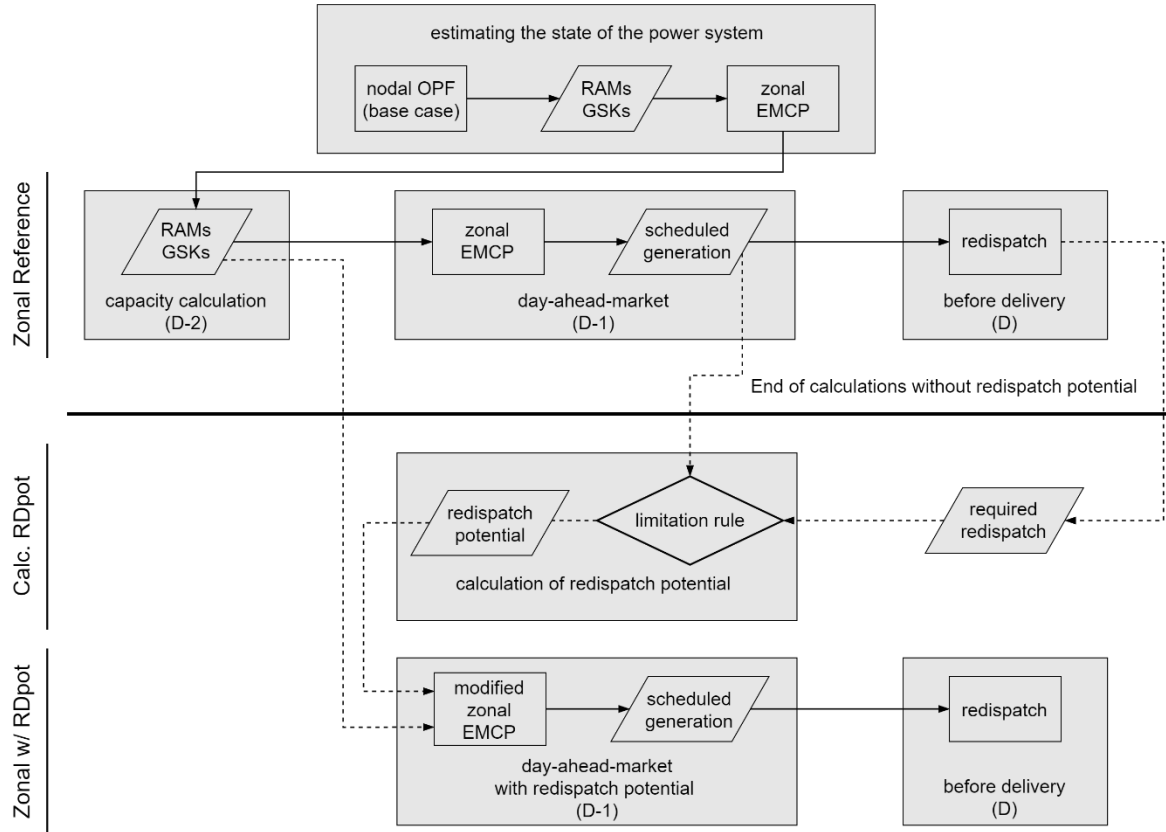


Figure 3: Model flow with a redispatch potential (based on Voswinkel et al. 2019)

The CNEs, the network elements for which the RAMs were calculated and which constrain the flow-based domain, were chosen based on the grid topology. All interconnectors—that is, network elements that cross zonal borders—were automatically considered CNEs. Additionally, internal network elements may qualify as critical if their sensitivity to zonal exchanges exceeds 5% (ACER 2019).

3.1.2 The market coupling problem with a redispatch potential

Integrating the redispatch potential requires further development and partial integration of the capacity calculation and redispatch planning processes. However, the determination of the capacity calculation inputs and the base case simulation remain unchanged in the proposed modeling framework. This also applies to the redispatch model, which uses the state variables of the market coupling model.

Consequently, the main difference is incorporating the redispatch potential and the corresponding decision variables into the day-ahead market-clearing problem, as presented in the following paragraphs.³ Newly added variables and equations are bolded, and decision variables are in capital letters:

$$\min \sum_{u \in U} c_u \cdot G_u + \mathbf{f^+ c_u \cdot RDpot_u^+} + \mathbf{f^- c_u \cdot RDpot_u^-} \quad (1)$$

$$\text{s.t.} \quad NEX_z = \sum_{u \in U_z} G_u - \sum_{i \in I_z} d_i \quad \forall z \in Z \quad (2)$$

$$\sum_{z \in Z} NEX_z = 0 \quad (3)$$

$$\sum_{u \in U} \mathbf{RDpot_u^+} + \mathbf{RDpot_u^-} = \mathbf{0} \quad (4)$$

$$g_u^{\min} \leq G_u + \mathbf{RDpot_u^+} + \mathbf{RDpot_u^-} \leq g_u^{\max} \quad \forall u \in U \quad (5)$$

$$\mathbf{0 \leq RDpot_u^+ \leq rdpot_u^{\max,+}} \quad \forall u \in U \quad (6)$$

$$\mathbf{rdpot_u^{\min,-} \leq RDpot_u^- \leq 0} \quad \forall u \in U \quad (7)$$

$$\begin{aligned} ram_f^{nsfd} &\leq \sum_{z \in Z} ptdf_{f,z} \cdot NEX_z + \sum_{i \in I} \sum_{u \in U^{RD-}} ptdf_{f,i} \cdot \mathbf{RDpot_u^-} \\ &+ \sum_{i \in I} \sum_{u \in U^{RD+}} ptdf_{f,i} \cdot \mathbf{RDpot_u^+} \leq ram_f^{sfd} \quad \forall f \in F^{CNE} \end{aligned} \quad (8)$$

In equation (1), the cost minimization problem is extended by adding the expected costs associated with the inclusion of the positive and negative redispatch potentials $RDpot_u^+$ and $RDpot_u^-$, respectively. Both potentials are multiplied by the associated costs c_u and redispatch penalty factors f^+ / f^- (see section 3.1.3). This ensures that the redispatch potential is utilized only when the additional costs related to the (expected later activation of the) redispatch potential are smaller than the cost savings from the additional cross-zonal exchange. The use of the redispatch potential is limited by equation (8). Equation (2) represents the demand balance and ensures that the net position is positive (negative) when generation exceeds (falls below) the electricity demand of the respective market zone.

Equation (4) balances the redispatch potential included in each time step. In equation (5), the redispatch potential is added to the generator constraints, ensuring that the generation plus the redispatch potential stays within the generator's technical limits. Equations (6) and (7) specify that the utilized redispatch potential $RDpot_u^+$ and $RDpot_u^-$ for each generation unit u must stay within the external

³ Please note that this contribution assumes the inclusion of the redispatch *potential only in the market clearing*, not the *activation* of redispatch units during the market-clearing stage, as considered in Poplavskaia et al. (2020).

bounds $rdpot_u^{max,+}$ and $rdpot_u^{max,-}$ set via the limitation rules (see section 3.2). Finally, the impact of the redispatch potential on line flows on critical network elements and the corresponding enlargement of the flow-based domain, as described in section 2, is modeled in equation (8). Here, the total redispatch potential in each direction per node i is multiplied by the nodal sensitivity $ptdf_{f,i}$ of the redispatch unit and may increase the cross-zonal exchange expressed via the zonal net position NEX_z , which is limited by the RAMs ram_f^{sfd} and ram_f^{nsfd} in the standard flow direction (sfd) and non-standard flow direction ($nsfd$) on each CNE f . If the minimum margins to increase cross-border trade are considered, ram_f^{sfd} and ram_f^{nsfd} are redefined as

$$ram_{f,minRAM}^{nsfd} = \min(ram_f^{nsfd}, R_{amr} \cdot F_{max}^{nsfd}) \quad \forall f \in F^{CNE} \quad (9)$$

$$ram_{f,minRAM}^{sfd} = \max(ram_f^{sfd}, R_{amr} \cdot F_{max}^{sfd}) \quad \forall f \in F^{CNE} \quad (10)$$

where R_{amr} is the minRAM factor (e.g., 70%) and $F_{max}^{sfd/nsfd}$ is the thermal capacity of the CNE in the standard and non-standard flow direction. Accordingly, the available margins were ensured to correspond to the minimum threshold of the thermal line capacity.

3.1.3 Redispatch problem

As explained in section 2, imperfections in FBMC necessitate corrective measures by the TSOs after the market clearing to maintain stable grid operations. Redispatch is carried out to avoid the violation of physical grid constraints by adjusting the output of generators.⁴

In modeling terms, this translates to an optimization problem in which the costs for generation adjustments are minimized, subject to the nodal transmission constraints, in accordance with a nodal DC load flow model. Due to regulations regarding cost compensation, which acknowledge the increased costs of generators when included in the redispatch process, penalty factors are introduced, adjusting the marginal costs of the generators (Higher Regional Court Dusseldorf, Decision of 4/28/2015). A general penalty is added, multiplied by the absolute amount of re-dispatched energy. This minimizes re-dispatched quantities and accounts for current practice, minimizing the number of interventions of TSOs in the market results.

The nodal balance q_i of the redispatch problem is given by the scheduled generation output g_u^* resulting from the market coupling optimization plus the activated positive and negative redispatch volumes $RD_u^+ + RD_u^-$ of all generation units u minus the vertical load d_i connected to the node i :

⁴ The redispatch problem is only briefly described in this section. For more details, including related equations, see Voswinkel et al. (2019).

$$q_i = \sum_{u \in U_I} (g_u^* + RD_u^+ + RD_u^-) - d_i \quad \forall z \in ZZ \quad (11)$$

The redispatch amounts for each generator are constrained by their minimum and maximum power outputs. Additionally, the generation capacity already dispatched in the market-clearing problem is subtracted from the generation constraints—a generator fully utilized in the market-clearing problem is not available for positive redispatch. Still, the generator can reduce its output through negative redispatch.

$$g_u^{min} - g_u^* \leq RD_u^+ + RD_u^- \leq g_u^{max} - g_u^* \quad (12)$$

3.2 Determination of the redispatch potential

In this contribution, we differentiate between the redispatch potential given to the market-clearing algorithm—that is, the generation units available for redispatch measures (see section 3.1.2)—and the activated redispatch measures optimized during the redispatch stage (see section 3.1.3). Determining the redispatch potential within the capacity calculation and redispatch planning process requires an estimation of the expected dispatch of generation units. Based on this estimation, the generation units available for redispatch can be identified.

From a market perspective, giving all the identified redispatch potential to the market-clearing algorithm would be preferable. However, as outlined in section 2, the generation units available for redispatch are estimated by TSOs two days before delivery. In addition to the uncertainty of the estimates, the effectiveness of a redispatch measure on congestion depends on the generator's location. Consequently, it would not be expedient to make all redispatch potential available to the market-clearing algorithm, as the uncertainty might lead to deviations between the market and redispatch stages and infeasible physical outcomes requiring further redispatch measures. In the following section, we propose three different limitation rules for determining and limiting the redispatch potential.

3.2.1 Available redispatch units

Available redispatch units are determined according to the expected dispatch of the standard zonal FBMC described in section 3.1.2 without considering the redispatch potential. This assumes perfect foresight of TSOs regarding generation and load forecasts and the system state. Based on their many years of experience with grid operation and redispatch, TSOs have a clear picture of the available redispatch units depending on the system state. Nevertheless, forecast deviations may lead to overloads of transmission lines during grid operation and deviations in the availability of redispatch units, which ultimately cause additional costs (Kloubert et al. 2015). However, forecast errors similarly affect the analyzed design options, but their detailed modeling is beyond the scope of this contribution.

The capacity of the generation units available for redispatch is determined as follows:

- Generation capacity available for **negative redispatch potential**: a reduction of the generation output $g_u^{zonal,ref}$ to provide negative redispatch requires an operation of the respective generation unit in the zonal reference. Otherwise, the negative redispatch potential $RDpot_u^-$ of generation unit u has to be zero. This is expressed by the assignment:

$$rdpot_u^{min,-} = -g_u^{zonal,ref} | u \notin U^{curtailment} \quad (13)$$

The market-based curtailment of renewable energy is correspondingly excluded from the negative redispatch potential.

- Generation capacity available for **positive redispatch potential**: an increase in generation to provide positive redispatch requires an operation of the respective generation unit in the zonal reference case below the maximum power output g_u^{max} . Otherwise, the available positive redispatch potential $RDpot_u^+$ of generation unit u has to be zero. This implies the assignment:

$$rdpot_u^{max,+} = g_u^{max} - g_u^{zonal,ref} \quad (14)$$

The two parameters $rdpot_u^{min,-}$ and $rdpot_u^{max,+}$ serve as input for the extended market coupling problem and constrain the utilized redispatch potential during the market-clearing stage (see equations (6) and (7)).

3.2.2 Redispatch potential limitation rules

The limitation of the redispatch potential is motivated by the trade-off between increasing cross-zonal trade during the market-clearing stage and maintaining system security during the redispatch (and grid operation) stage. Integrating all available redispatch potential units into the market based on nodal sensitivities would come close to computing a nodal dispatch. This might give rise to the question why the zonal dispatch is maintained at all. More importantly, the limitation of the redispatch potential avoids a too extensive re-optimization of the zonal market-clearing solution and thus facilitates the TSO task of maintaining system security. Also, redispatch potential might otherwise reduce the objective function value (see equation [1]) without increasing cross-border trade.

The first limitation rule addresses the effectiveness of redispatch measures. Accordingly, interventions on market outcomes of generation units with low sensitivities on CNEs are avoided. In other words, ineffective redispatch units are excluded. Using the subsets for negative and positive redispatch potential based on equations (13) and (14), pairwise sensitivities between generation units available for $rdpot_u^{min,-}$ and $rdpot_u^{max,+}$ are determined. According to equations (17) and (18), the generators u

forming the top three highest pairwise sensitivities on a CNE for both directions are selected for the redispatch potential given to the market-clearing algorithm. One generator can be part of several pairs.

- I. **RDpot_sens**: a limitation to generation units available for negative or positive redispatch potential and having sufficiently large pairwise sensitivities on the considered CNEs. The rule is best expressed mathematically by first constructing the set of sensitivities S_f for a given CNE f for all pairs of generators $(u, u') \in U^+ \times U^-$. Thereby U^+ and U^- indicate the set of generators with available redispatch potentials strictly different from zero, i.e.:

$$\begin{aligned} U^+ &= \{u \in U \mid rdpot_u^{max,+} \neq 0\} \\ U^- &= \{u \in U \mid rdpot_u^{min,-} \neq 0\} \end{aligned} \quad (15)$$

The set of sensitivities S_f can then be written as:

$$S_f = \{(ptdf_{f,u} - ptdf_{f,u'}), u \in U^+, u' \in U^-\} \quad (16)$$

Introducing the notation $S_f^{(k+)}$ and $S_f^{(k-)}$ to indicate the subset of the top k positive (largest) and negative (lowest) values of set S_f , the available redispatch potentials under this rule can then be written as:

$$\begin{aligned} rdpot_{u'}^{min,-,sens} &= \begin{cases} rdpot_{u'}^{min,-} & \text{iff } \exists f \exists u, (ptdf_{f,u} - ptdf_{f,u'}) \in S_f^{(3+)} \cup S_f^{(3-)} \\ 0 & \text{otherwise} \end{cases} \end{aligned} \quad (17)$$

$$\begin{aligned} rdpot_u^{max,+,sens} &= \begin{cases} rdpot_u^{max,+} & \text{iff } \exists f \exists u', (ptdf_{f,u} - ptdf_{f,u'}) \in S_f^{(3+)} \cup S_f^{(3-)} \\ 0 & \text{otherwise} \end{cases} \end{aligned} \quad (18)$$

The second limitation rule emphasizes the maintenance of system security. Suppose that a CNE is congested in the zonal reference case. In this case, the utilization of the redispatch potential aims to increase the flow capability of this CNE (which increases the flow-based domain). Consequently, the zonal dispatch changes and cross-zonal trade increases. However, using the redispatch potential combined with the zonal approximation based on generation shift keys tends to increase the (physical) congestion on the CNE and the redispatch needed during grid operation. Finally, suppose there is a considerable need for redispatch already in the zonal reference case. In that case, considering the same generation units as the redispatch potential may lead to a conflict of use. Accordingly, the generation units activated for redispatch in the zonal reference case are excluded from the set of redispatch potentials determined according to the first limitation rule.

- II. **RDpot_sens_red**: a limitation to generation units or generation capacity considered under the first limitation rule and, in addition, not activated during (or “scheduled” for) the redispatch stage:

$$rdpot_{u'}^{min,-,sens_red} \quad (19)$$

$$= \begin{cases} rdpot_{u'}^{min,-,sens} & \text{iff } \exists u, RD_u^{+,ref} = 0 \wedge RD_u^{-,ref} = 0 \\ 0 & \text{otherwise} \end{cases}$$

$$rdpot_u^{max,+,sens_red} \quad (20)$$

$$= \begin{cases} rdpot_u^{max,+,sens} & \text{iff } \exists u, RD_u^{+,ref} = 0 \wedge RD_u^{-,ref} = 0 \\ 0 & \text{otherwise} \end{cases}$$

The variables $RD_u^{+,ref}$ and $RD_u^{-,ref}$ in equations (19) and (20) result from the nodal balance constraint of the redispatch problem of the zonal reference case (see equation [9]).

4 Case study

4.1 Data and scenario framework

For the case study, a scenario was built considering the state of grid development and renewables expansion in 2022. Input prices, such as fuel and CO₂ prices, are based on pre-crisis expectations (before 2022) to suppress temporary distortions in electricity markets in our analysis (see also below).

The spatial coverage of the transmission grid comprises the Core region (i.e., Central Western Europe⁵ plus Switzerland) and Central Eastern Europe.⁶ The grid model is based on publicly available data, such as the static grid models of the TSOs and information provided in the network development plans (50Hertz et al. 2019; Entso-E 2021b; JAO 2021; OpenStreetMap 2021). Approximately 2,700 nodes and more than 5,000 branches were modeled, including lines and transformers. Additionally, interconnectors to all other European countries were incorporated. Accordingly, the market simulations were carried out for Europe considering a hybrid approach in which the FBMC method is applied for the Core region and the NTC approach for the remaining countries.

Information for generation capacities was taken from the generator database of the Chair of Energy Economics and Management Science at the University of Duisburg-Essen. This database is mainly based on the Platts power plant database and enhanced by plant-specific research, primarily relying on plant owners' web presence and press releases and publicly available databases (Platts 2018; Bundesnetzagentur 2020). Aggregate installed capacities for conventional power plants and renewable-

⁵ Austria, Belgium, France, Germany, Luxembourg, the Netherlands, and Switzerland

⁶ Poland, Czech Republic, Hungary, Slovenia and Slovakia

based generators were adjusted to match the status quo of 2022 (Entso-E 2021a). The nodal distributions of the installed capacity of renewable and conventional power plants are shown in Figure 4 and Figure 5.

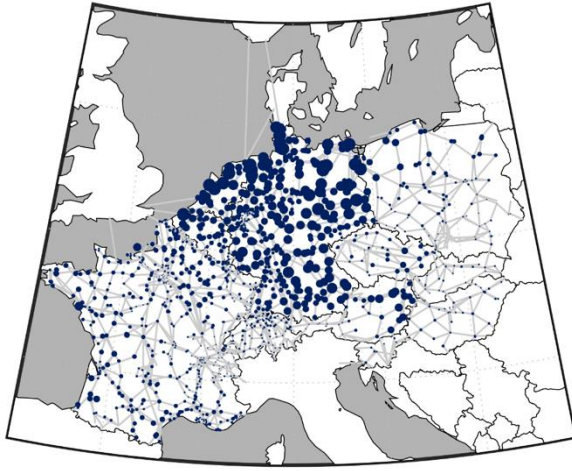


Figure 4: Distribution of renewable nodal capacity

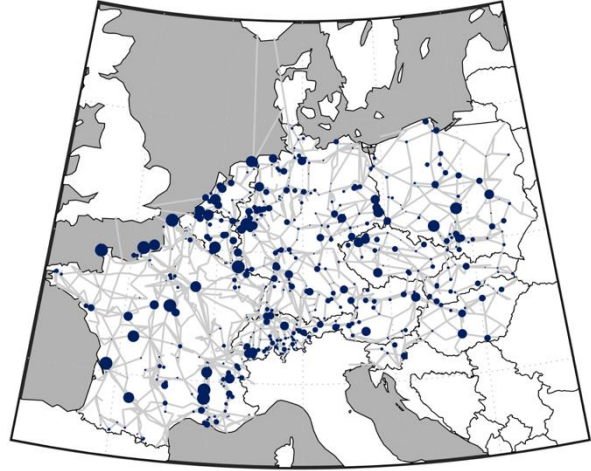


Figure 5: Distribution of conventional nodal capacity

Electricity demand data were generally taken from Entso-E (2021a). For Germany, load data from Baginski et al. (2018) were used to have more appropriate forecast data for the calculation year 2022. Renewables infeed values were modeled for each node based on a bottom-up approach, as described in Felten et al. (2019) and different input data sources (Baginski et al. 2018; Open Power System 2020). To derive a conservative estimation of the impact of the discussed methodological adaptations, we took the renewables infeed of the low value scenario for 2022 specified by Baginski et al. (2018) for Germany as one of the major redispatch demand-driving countries.

For the input prices, we used quotations for fuel and CO₂ futures from the European Electricity Exchange—that is, three-month averages of the 2025 futures price notations from the fourth quarter of 2021 (before the Ukraine crisis) for coal, natural gas, fuel oil, and light oil and CO₂ certificates (energate 2022). The price for CO₂ certificates amounts to 70.15 EUR/t CO₂. The prices for nuclear and lignite are based on values used in the German Grid Development Plan (50Hertz et al. 2019). The range of the marginal costs obtained for the corresponding generation technologies in the Core region is shown in Figure 6.

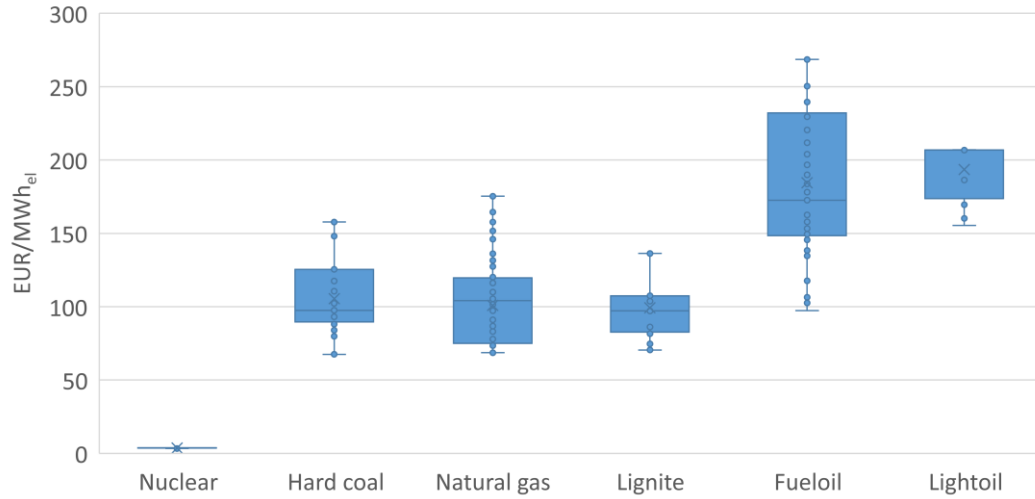


Figure 6: Marginal generation costs of conventional generation technologies

A threshold of 70% was considered for implementing minRAMs in the Core region. This assumption deviates from the current practices of Core TSOs, which partly foresee derogations from the 70% minRAM before 2025 (e.g., Germany, Poland, and the Netherlands) (ACER 2022). For modeling the integrated redispatch potential during the market-clearing stage and activating redispatch measures during the redispatch phase, penalty factors of 0.9 for downward and 1.2 for upward redispatch were assumed. As described in section 3.1.3, the penalty factors consider current compensation rules and support the efficient utilization of redispatch.

4.2 The obtained redispatch potential and its utilization

First, the results of determining the redispatch potential are presented. Subsequently, the use of the redispatch potential in the market-clearing model is illustrated before discussing the impacts of this potential in the next subsection. Theoretically, the model region's re-dispatchable maximum generation capacity amounts to 250.8 GW. The generation units available for positive and negative redispatch potentials vary depending on the respective generation and load situations (see section 3.2.1). Considering all available redispatch units in the set of redispatch potentials according to equations (13) and (14), the hourly positive full redispatch potential varies between 55.8 GW and 207.2 GW, averaging 135.3 GW. The range of negative redispatch potentials is similar, from -58.8 to -195.0 GW (-120.4 on average). For comparison, the redispatch potential without limitation is referred to as **RDpot_unlim** in the following paragraphs.

- **RDpot_sens** excludes ineffective redispatch units and considers only available redispatch units with a high positive impact (i.e., nodal sensitivity) on network elements at maximum capacity. Under this limitation rule, the hourly positive (negative) redispatch potential ranges from 36.0 to 102.4 GW (-48.6 to -126.8 GW). These are very high capacities that are fed into the market-clearing algorithm as redispatch potentials. This is because the figures include generation

units that are part of the top three highest pairwise sensitivities on any CNE for both directions. However, the results reveal that despite the large redispatch potential, only small fractions (around ± 0.9 GW on average) are utilized in the market-clearing algorithm (see also Figure 7).

- **RDpot_red** emphasizes the maintenance of system security and considers a limitation to generation units or generation capacity not activated during (or “scheduled” for) the redispatch stage of the zonal reference case. The resulting redispatch potential is very close to the full redispatch potential, as only activated (or scheduled) generation units are excluded. Accordingly, the hourly positive (negative) redispatch potential ranges from 33.8 to 99.6 GW (-47.3 to -126.4 GW). Again, these very high values may be counterintuitive in the context of system security. Yet, this limitation rule addresses the use conflict described in section 3.2.2 and leaves the selection of efficient redispatch potentials to the market-clearing algorithm (limiting the possibility of discretionary choices by TSOs).

Figure 7 shows the hourly net effect of the utilized redispatch potential on welfare resulting from market clearing and redispatch. In most hours, using a redispatch potential increases welfare. However, there are situations in which the utilization of the redispatch potential results in an overall welfare loss—that is, when redispatch costs exceed the welfare gain in the market-clearing stage. The occurrence of such situations can be reduced when applying the limitation rules. For instance, under RDpot_sens_red, the number of hours with welfare loss are reduced from 2,475 to 1,838 hours per year. This reduction corresponds to a decrease in inefficiency from 22 to 13 M€ per year. Further details on the market impacts are discussed in the next section.

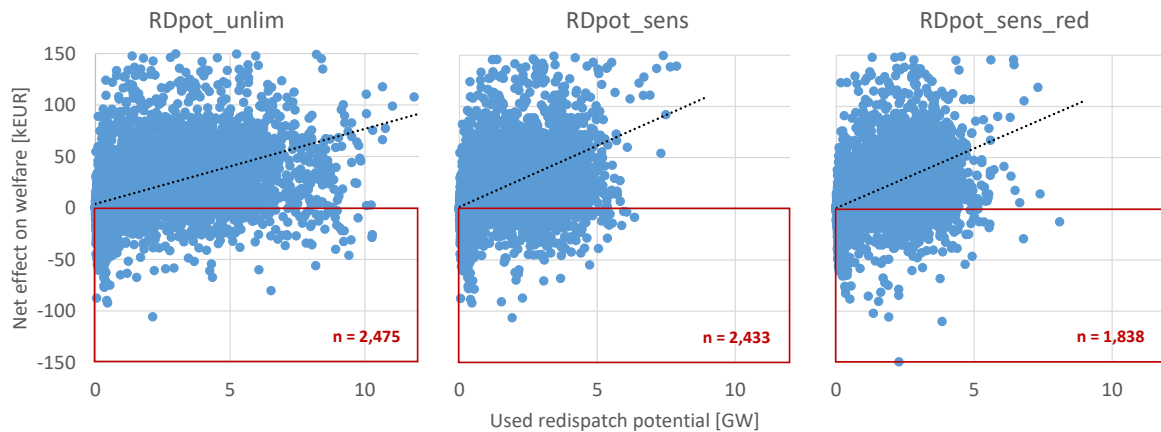


Figure 7: Utilized redispatch potential and its net effect on system costs for all 8,760 hours of one year

The following exemplary situation illustrates the utilization of redispatch potentials in the model. Figure 8 shows all modeled transmission lines in gray and CNEs always binding in the market coupling problem in black. The red lines indicate binding CNEs without the utilization of a redispatch potential, and the green lines show CNEs binding after the utilization of the redispatch potential. The utilized

redispatch potential is characterized by red (downward) and blue (upward) triangles. Moreover, the black open triangles show the changes in the zonal net position after utilizing the redispatch potential.

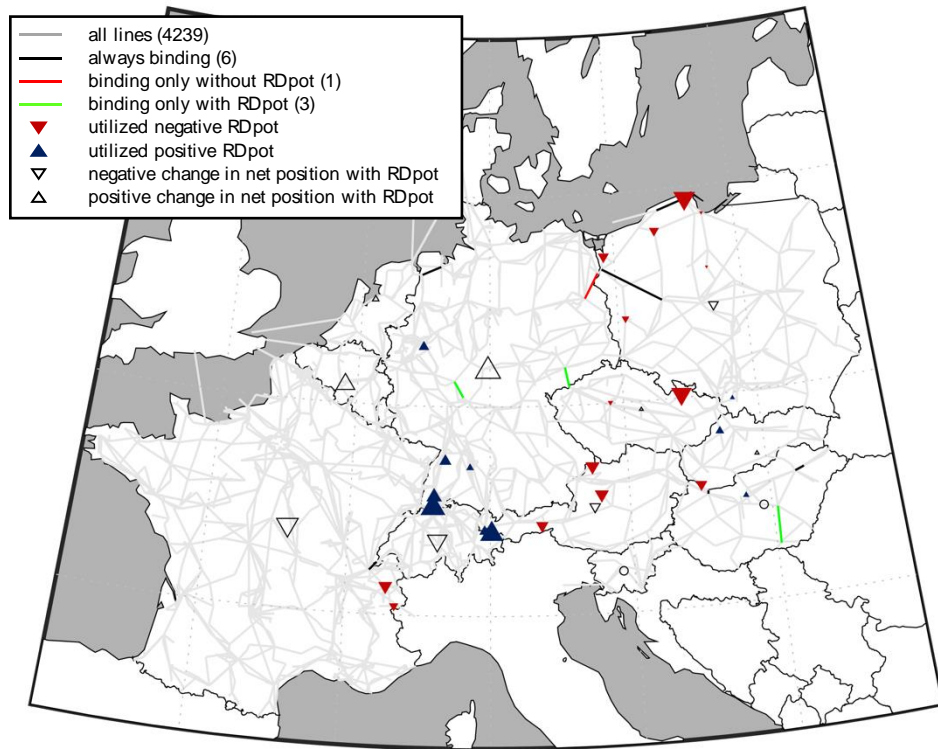


Figure 8: Utilization of the redispatch potential and binding CNEs for a situation with a high load and wind infeed

The exemplary situation with high electricity demand and a high infeed from wind energy (mainly at the northern periphery of the Core region) is associated with considerable north–south transit. Without a redispatch potential, Germany’s export is limited by a CNE at the border to Poland. France has to counter the flows from the north and export more than 8.5 GW. With a redispatch potential, binding CNEs and net positions change. The utilization of a redispatch potential in southern Germany and Switzerland relaxes the available margins on internal CNEs in Germany, moving the “center of gravity” for constrained lines further south.

Consequently, Germany’s net position increases by 6.7 GW during the market-clearing stage. At the same time, France and Switzerland reduce their net positions by 5 GW and 4 GW, respectively. Overall, cross-border trade can be increased by 1.4 GWh for the considered hour in the Core region. This case shows that including a redispatch potential allows for more efficient utilization of the existing infrastructure. The following section discusses the results at the aggregate level.

4.3 Impact of the redispatch potential

4.3.1 Market effects

Both concepts (i.e., minimum margins and redispatch potential) aim to improve cross-border trade and price convergence. Relaxing transmission constraints using minimum margins or redispatch potentials enlarges commercial capacities (i.e., flow-based domains) and increases cross-border trade.

Figure 9 shows the effects on **cross-border trade** for the *minRAM* and *RDpot* cases individually and combined. Among the individual measures, *minRAM* exhibits the largest increase in cross-border trade. The sweeping increase in commercial capacities enabled by *minRAM* allows for a considerable increase in cross-border trade of 19.3 TWh, corresponding to 14%. Including redispatch potentials induces higher cross-border trade by up to 9.5 TWh (8%). Depending on the limitation rule and the limitation of the redispatch potential, the benefits regarding cross-border trade are reduced to 6.1 TWh compared to the reference case. Combining *minRAM* and *RDpot* allows for a total increase in cross-border trade in the range of 20.7 to 22.0 TWh.

Regarding the effect of *minRAM* on individual countries, imports to Belgium are reduced (−38%), while imports to Poland (+142%) and Germany (+14%) are increased. Exports from Germany, France, the Netherlands, and Hungary increase substantially. At the same time, *RDpot* increases imports mainly to Central Eastern Europe and Switzerland, while exports from Germany and France increase. Overall, the effects are less extreme and somewhat balanced across the capacity calculation region under *RDpot*. Both approaches, *minRAM* and *RDpot*, result in reduced CO₂ emissions, mainly driven by increased exports of wind energy from Germany and nuclear energy from France, balancing decreased generation using coal and lignite in Germany and Poland (see Figure 16 in the Appendix).

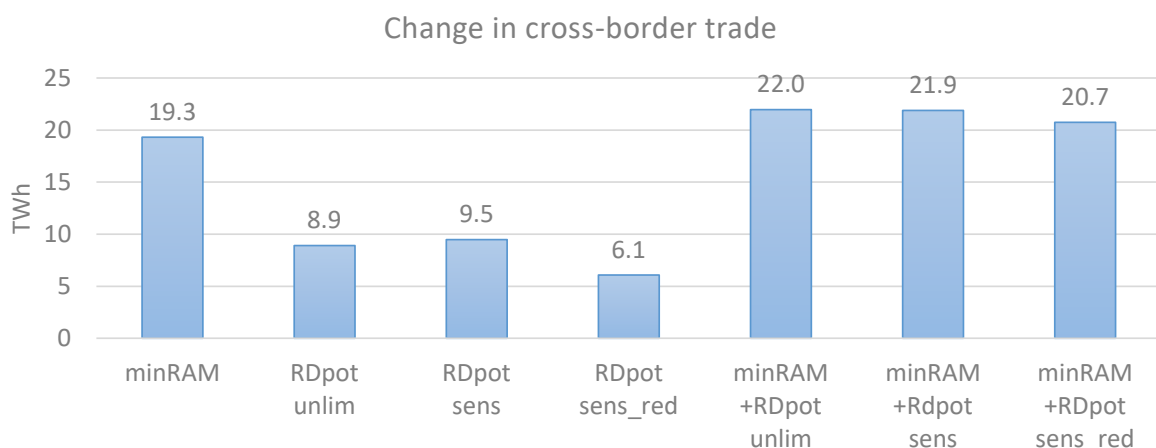


Figure 9: Change in cross-border trade (sum of exports) compared to the reference case

A decrease in price spreads is equivalent to an increase in the **convergence of electricity market prices** and a result of reduced (market) congestion between the bidding zones. The average price spread is

defined as the average difference between the hourly minimum and maximum price in the Core region over all hours of the year.

The changes in the average price spread compared to the reference case are shown in Figure 10. The results follow the same pattern as the change in cross-border trade discussed above. However, the gap between the *minRAM* and *RDpot* solutions is smaller than the change in cross-border trade. Without combining the design options, the application of minimum margins decreases the average price spread to a greater extent (-6.1 €/MWh) than the inclusion of redispatch potentials (up to -4.9 €/MWh), whereby the more restrictive limitation rules induce smaller changes (-3.1 €/MWh for the most restrictive rule). Combining *minRAM* with *RDpot* allows for a considerable further decrease in price spreads. In this case, limiting the redispatch potential has no substantial effect.

The decrease in price spreads can be attributed to two effects. On the one hand, both concepts lead to a reduction in (very) high electricity prices. Based on a maximum price of 182.68 €/MWh under the reference case, applying minimum margins leads to a decrease of 61.65 €/MWh. When including redispatch potentials, the reduction of peak prices ranges from 40.48 to 50.87 €/MWh. Combining both approaches achieves a decrease in the range of 57.80 to 70.72 €/MWh. Consequently, *minRAM* and *RDpot* contribute to stable electricity prices in high-demand and scarcity situations. On the other hand, *minRAM* reduces the occurrence of negative prices resulting from increased cross-border exchange capabilities and the reduced market-based curtailment of wind generation.

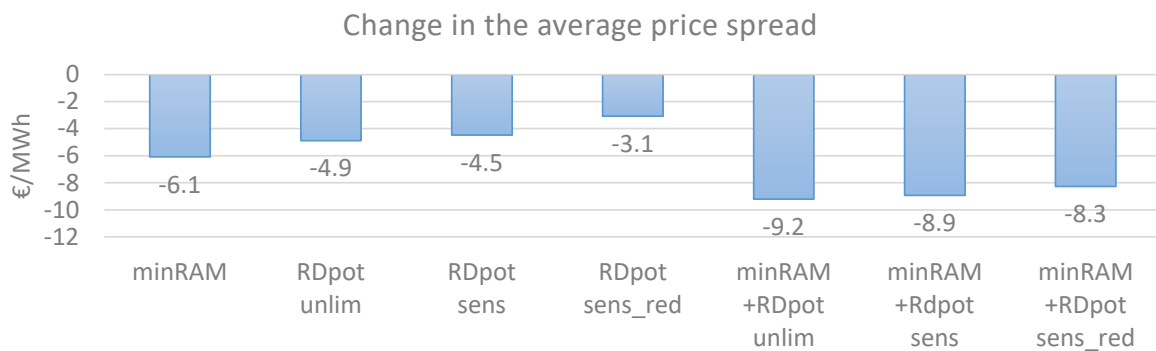


Figure 10: Change in the average price spread compared to the reference case

From a market perspective, increased cross-border trade and price convergence due to minimum margins and redispatch potential are expected to reduce market-clearing costs. However, the analysis needs to incorporate the redispatch stage to provide a complete picture of the overall (socio-economic) cost. Figure 11 shows the differences in the **market-clearing and redispatch costs** compared to the reference case. Moreover, the net welfare effect (i.e., the change in total costs) is depicted in the boxes.

For *minRAM*, the sweeping increase of commercial capacities to a minimum level reduces market-clearing costs while significantly increasing redispatch costs. The latter overcompensates the cost reduction, leading to an overall welfare loss of 107.3 M€ per year, confirming the results of Schönheit et al. (2021a). Nevertheless, this welfare loss must be regarded under the assumed *minRAM* of 70% and redispatch penalty factors, which may overestimate the actual redispatch costs. At the same time, the implicit assumption of a perfectly coordinated cross-border redispatch might underestimate redispatch costs.⁷

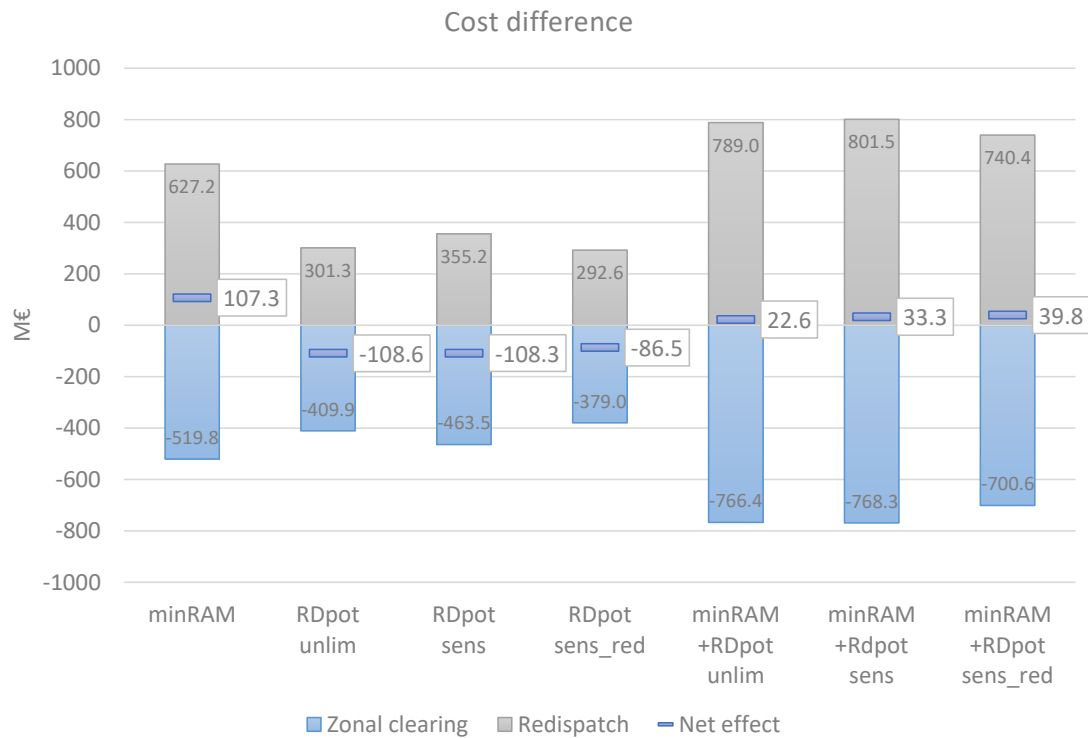


Figure 11: Change in the market-clearing and redispatch costs compared to the reference case

Using the redispatch potential approach allows for increasing commercial capacities whenever efficient—that is, when the costs of securing increased commercial capacities via (virtual) redispatch are lower than the achieved reduction of market-clearing costs. Compared with *minRAM*, considering redispatch potentials reduces the effects on market-clearing and redispatch costs, and an overall welfare gain of up to 108.6 M€ per year is obtained. Market-clearing costs in *RDpot_sens* are lower than in *RDpot_unlim*. Here, limiting the redispatch potential reduces the re-optimization of the zonal market clearing where it does not increase cross-border trade. Consequently, there is a shift from market

⁷ For perspective, a sensitivity with a low *minRAM* of 31% leads to an overall cost decrease of 39.3 M€ per year, which is still less than the cost reductions achieved with an integrated redispatch potential. Moreover, excluding the redispatch penalty factors reduces redispatch costs for all scenarios, whereby the comparison of *minRAM* and the redispatch potential is not impacted.

clearing to (calculatory) redispatch potential costs (see Figure 17 in the Appendix), and cross-border trade is slightly higher under *RDpot_sens*.⁸

Combining *minRAM* with *RDpot* helps to partly compensate for the adverse effects of *minRAM*. However, an overall welfare loss is still observable, albeit reduced to about 40 M€ per year.

Both approaches, minimum margins and redispatch potentials, lead to an increase in cross-border trade. In light of the cost effects discussed above, Figure 12 puts the change in total costs in relation to the additional cross-border trade.

For *minRAM*, the additional costs associated to the additional cross-border trade of 19.3 TWh leads to an average cost of 5.6 €/MWh_{addTrade}. In contrast, in all three cases with redispatch potential alone, the additional cross-border trade leads to an overall cost reduction that may reach up to 14.2 €/MWh_{addTrade}. *RDpot_sens_red* achieves the best benefit-to-effort ratio.

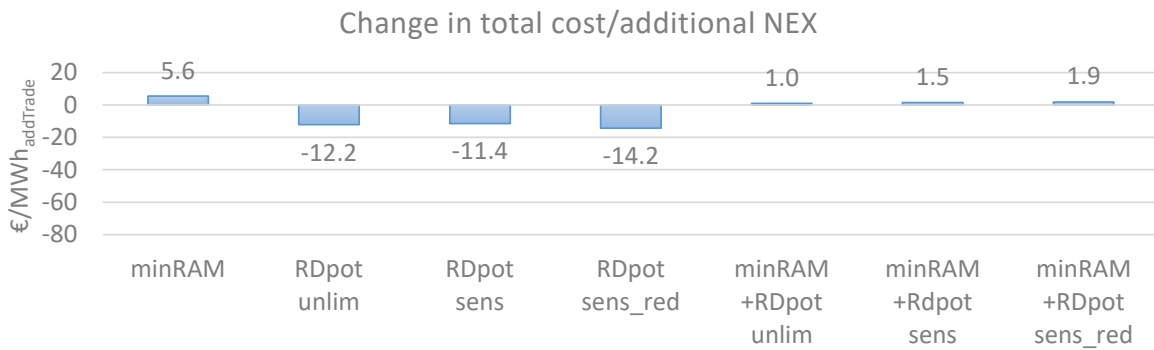


Figure 12: Change in total costs per unit of additional cross-border trade compared to the reference case

4.3.2 System operation effects

The analysis of the effects of introducing minimum margins or redispatch potentials revealed increased redispatch costs. This indicates an increase in grid congestion, which implies a trade-off between economic benefits and system security.

Corresponding to the increased redispatch costs, Figure 13 shows the change in the average number of **violated transmission constraints** implied by the market results before the utilization of congestion management measures (i.e., redispatch). The pattern corresponds to the results detailed above, with the redispatch potential leading to a third of the additional violated constraints in the *minRAM* case.

⁸ The re-optimization of the zonal market clearing using the redispatch potential could be avoided by implementing an additional constraint suppressing the overall negative costs for the redispatch potential (see also equation [1]). However, this constraint may also suppress situations where pairs of negative and positive redispatch potentials have negative costs and increase cross-border trade. Consequently, we refrained from implementing such a constraint.

Combining *minRAM* and *RDpot* leads to the most violated constraints. In this regard, limiting the re-dispatch potential according to the second limitation rule (*RDpot_sens_red*) has a noticeable impact on the number of violated constraints.

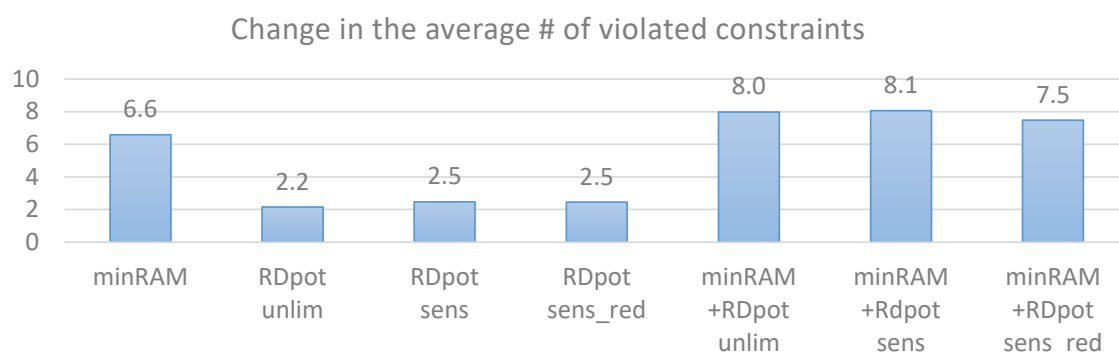


Figure 13: Change in the average number of violated constraints compared to the reference case

Figure 14, showing the change in the average number of **redispatch measures**, and Figure 15, depicting the overall change in **redispatch volume**, exhibit similar patterns. An increased number of violated constraints comes with an increase in redispatch measures and volumes. Under *minRAM*, the redispatch volume rises by 13.2 TWh, which is almost +20% compared to the 67 TWh in the reference case in the Core region.⁹ Including redispatch potentials increases volumes by only 5.8 TWh to 8.1 TWh, depending on the limitation rule. Again, the combination of *minRAM* and *RDpot* leads to the highest overall increase.

The higher increase in redispatch volumes under the *minRAM* approach links back to the economic impact. The sweeping definition of minimum margins leads to more violations of grid constraints and a higher number of required redispatch measures. To relieve grid congestion, TSOs must increasingly rely on less efficient redispatch units (i.e., located farther from grid congestion and with lower sensitivity to the congested grid element), leading to higher (specific) redispatch costs.

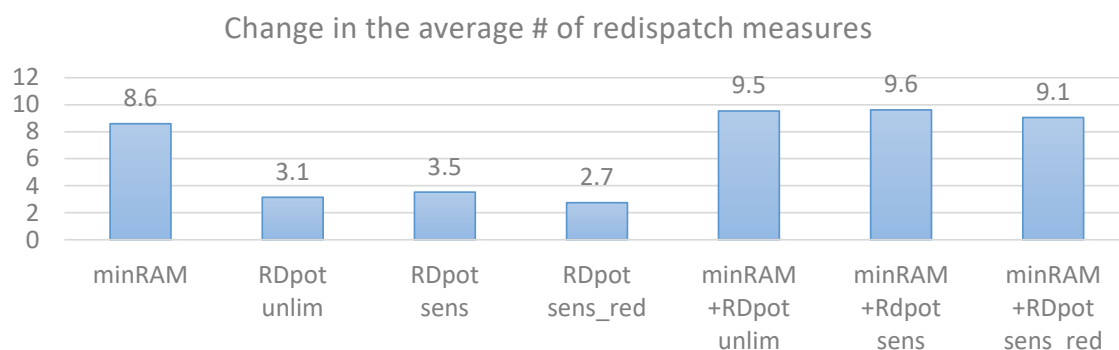


Figure 14: Change in the average number of redispatch measures compared to the reference case

⁹ For comparison, the total redispatch volume in the considered model region in 2020 was 47 TWh (ACER and CEER 2021).

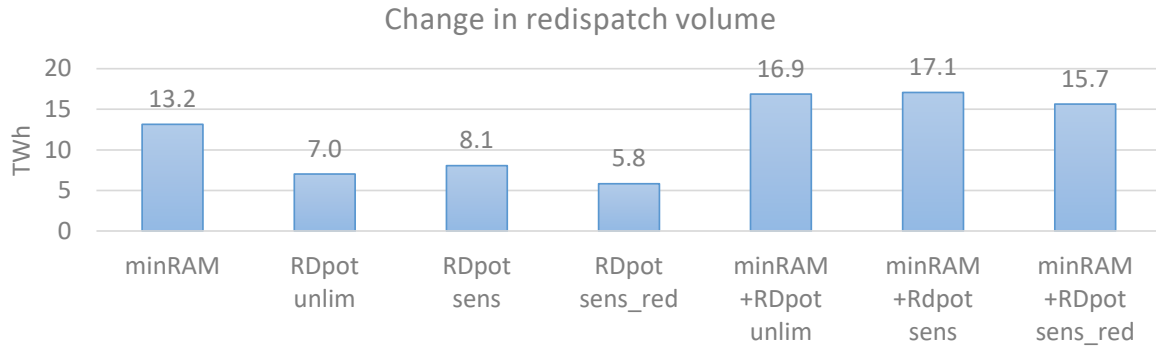


Figure 15: Change in redispatch volume (positive and negative) compared to the reference case

When assessing the outcomes of the analysis, some limitations of the approach must be kept in mind. Notably, the model includes cross-border redispatch, which is currently not perfectly coordinated in the Core region. Regarding integrating the redispatch potential, we may overestimate the resulting benefits in the market-clearing stage. Moreover, the model may underestimate redispatch amounts and costs, affecting all cases. Conversely, negating derogations from the 70% minRAM before 2025 and phase-shifting transformers may imply higher redispatch volumes and costs. Additionally, positive economic real-world implications for investors, which may emerge due to higher price convergence, were not taken into account in this paper. Nevertheless, as the analysis is based on comparing alternative cases relative to a reference case, we do not expect the conclusions to be affected by changes in these assumptions.

5 Conclusions and policy implications

This contribution is motivated by the ongoing debate about further developing the European electricity markets and congestion management. Several recent studies discussed market design options to increase cross-border trade through market-based redispatch mechanisms (Hirth and Schlecht 2020; Schlecht and Hirth 2021; Ehrhart et al. 2022). This paper focuses on an option in which the TSO is responsible for providing the market with the available redispatch potential. It sheds light on the market and system operation effects of minimum margins (i.e., minRAMs) vs determining and integrating redispatch potentials using a large-scale model covering (most of) the Core capacity calculation region.

The results show that the minRAM approach is most effective regarding additional cross-border trade and increasing price convergence. However, a sweeping increase in cross-border capacities can lead to inefficiencies. Moreover, implementing the minRAM approach leads to a higher frequency of violations during grid operation and an increased need for redispatch measures. Our analysis reveals an overall cost increase (i.e., welfare loss) due to the minRAM approach, mainly caused by higher redispatch costs outweighing the benefits of increased cross-border trade.

The inclusion of redispatch potentials is equally effective regarding improved price convergence in the Core region, whereas the increase in cross-border trade is lower than within the minRAM approach. However, using redispatch potentials leads to a more efficient increase in cross-border capacities and helps reduce system costs (or increase welfare) in the Core region. These results align with the findings yielded by a small test system studied by Poplavskaya et al. (2020). The approach mimics the physical reality of the underlying transmission system more closely and hence induces fewer additional redispatch measures compared to the minRAM method.

Based on our analysis, it can be concluded that including redispatch potentials is more efficient for increasing cross-border trade and maintaining system security and should replace the minRAM approach. However, removing the already implemented minRAM method may be politically difficult to push through. This may be even more true since a primary political objective at the European level has always been to facilitate cross-border trade.

If this political objective remains a dominant premise, the already implemented minRAM approach should be extended to include redispatch potentials. In the case of combining the two methods, our analysis indicates an improved net effect of roughly 80 M€ per year. Accordingly, potential efficiency losses due to the minRAM approach can be compensated for by efficiency gains through integrating redispatch potentials into the market clearing. The latter effect is mainly driven by the further increase in the RAM (beyond 70%) by utilizing redispatch potentials when efficient. However, politically accelerated renewables integration plans and sector coupling may significantly increase redispatch volumes and costs in the future if progress regarding network extension remains (too) slow. If this induces a shift in political targets toward system security, including redispatch potentials is a promising alternative for maintaining high cross-border exchanges while limiting redispatch volumes in the transmission grid.

When implementing redispatch potentials in the market-clearing stage, additional aspects are relevant:

- TSOs face a trade-off between defining and giving redispatch potentials to the market and securing grid operation. The selection of generation units for the redispatch potential affects its effectiveness and efficiency. Redispatch potential limitations and selection rules, as proposed in this contribution, may help to overcome or alleviate this issue. Moreover, the definition of the redispatch potential should be embedded in a monitoring process to avoid potentially arbitrary choices made by TSOs.
- Implementing redispatch potentials in the market clearing should align with the respective compensation rules for redispatch. This maintains consistent economic incentives between the market-clearing and redispatch stages.

- The integrated redispatch potential approach may be extended to other market time frames, such as intraday. When moving closer to real time, interactions between utilizing redispatch potentials to increase cross-border trade and the resulting redispatch requirements may yet create challenges for system operation and security. Moreover, day-ahead markets are more critical in terms of trading volumes and potential welfare impacts.
- To fully utilize the benefits of including redispatch potentials, the coordination of redispatch measures between TSOs and across bidding zones should be improved. This improvement would support the efficiency of integrating redispatch potentials and the overall efficiency of the FBMC process, including minRAMs.
- Poplavskaya et al. (2020) mention the issue of potential strategic bidding when generators are often activated for integrated redispatch. However, this contribution assumes only the consideration of redispatch *potentials* and not the *activation* of redispatch units during the market-clearing stage. Nevertheless, the issue of potential strategic bidding remains. In the case of cost-based redispatch, including redispatch potentials does not yet create additional strategic bidding potential. Consequently, changes in the zonal delimitation should rather be used to address structural congestions (that amplify potential strategic bidding).

From a broader perspective, integrating national power markets into a single European market forms a central pillar for a secure, sustainable, and efficient electricity supply. Increasing cross-border trade supports market integration. Grid expansion is the primary measure used to increase cross-border capacities in the long run. In the mid-term, the bidding zone review addresses congestions limiting cross-border trade. Before real-time system operation, the market coupling process and remedial actions—such as redispatch—allocate existing cross-border capacities. Consequently, integrating redispatch potentials in market clearing addresses the short-term optimization of existing capacities and supports cross-border trade and market integration in Europe. According to the results of this study, the design options considered contribute to limiting electricity prices in high-demand and scarcity situations.

The recent strengthening of climate and renewable energy targets is associated with an increased need for transport infrastructure to integrate climate-neutral generation and flexibility into energy systems. Against the background of already delayed grid expansion plans and indecisive past bidding zone reviews, short-term measures, such as implementing redispatch potentials in market clearing, are effective for increasing cross-border trade and support the integration of renewable energy sources.

CRediT authorship contribution statement

Michael Bucksteeg: conceptualization, methodology, software, validation, formal analysis, investigation, data curation, writing (original draft), writing (reviewing and editing), and visualization. **Simon Voswinkel**: methodology, software, validation, formal analysis, investigation, data curation, writing (original draft), writing (reviewing and editing), and visualization. **Gerald Blumberg**: data curation (grid model), validation, and writing (reviewing and editing).

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Appendix

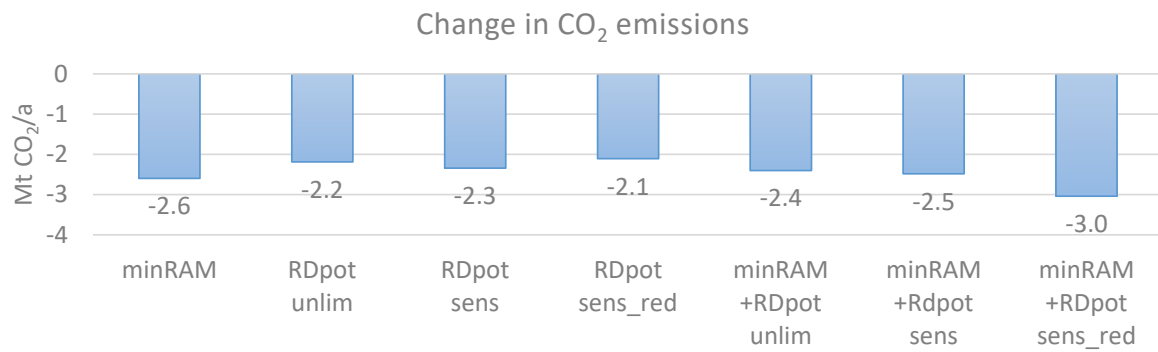


Figure 16: Change in CO₂ emissions compared to the reference case

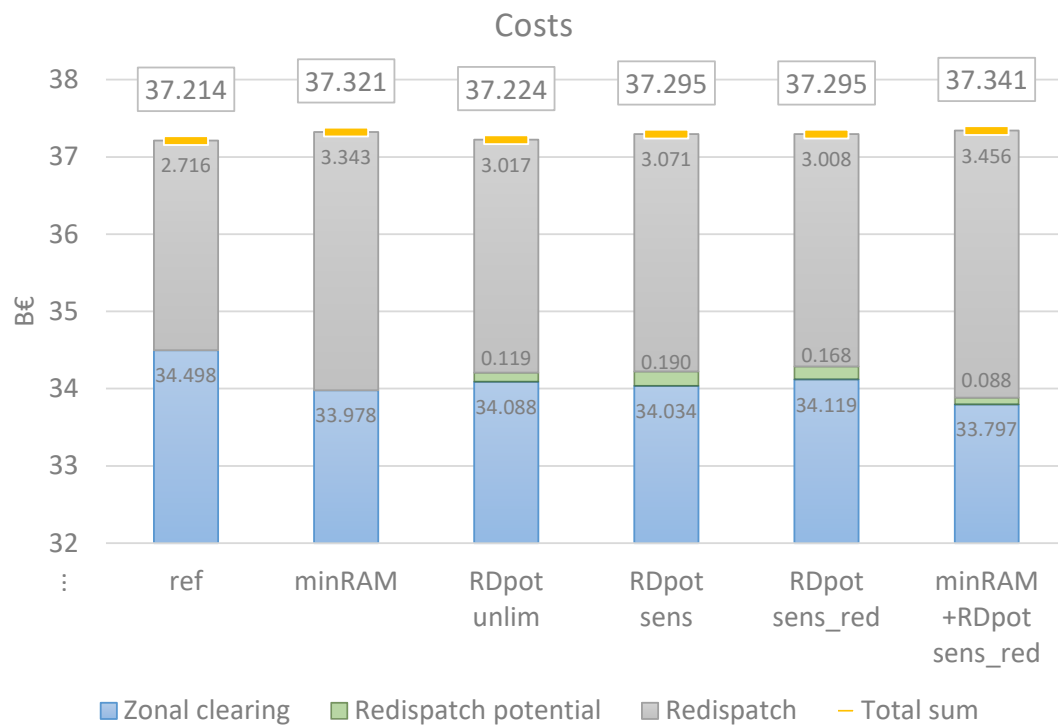


Figure 17: Absolute cost values, including (virtual) costs for redispatch potential