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Powering up the grid

A partial welfare analysis of redispatch in the Swedish electricity grid

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Att utvidga kraften av det befintliga elnätet

En partiell samhällsekonomisk analys gällande avhjälpande åtgärder i det svenska elnätet

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Abstract

Congestion rates in the electricity grids of Sweden and other European nations are rising, caused by a number of coinciding trends combined with lagging grid expansion. The costs for remedial actions (mainly redispatch) required to resolve these congestions have grown and are expected to continue growing. Redispatch costs are indirectly financed by consumers, who are less sensitive to price than generators. While redispatch is a necessary action to maintain grid stability, its quantitative welfare impact has not been evaluated in the Swedish grid context. Earlier studies on welfare impact from redispatch in the European grid result in a negative net welfare impact from redispatch, but these results may not be applicable to Sweden given its high share of hydro power and more granular pricing mechanism with bidding zones. The theoretical framework suggests that the welfare impact from redispatch depends much on the context. To investigate whether redispatch is motivated from a welfare standpoint, this study analyses how redispatch affects the Electricity Market Utility (which is a welfare measure with four components: consumer surplus, producer surplus, congestion rent, and redispatch costs). The EMU is compared between day-ahead and at delivery hour, isolating the effect of redispatch on the four components. The data is obtained from a simulation by ENTSO-E, where the simulation is designed to resemble the grid of 2025. This model is highly detailed with a few limitations that could also be be contributional. For example, applying only one weather year provided event-specific insights about the welfare impact from redispatch. The temporal analysis indicates that redispatch has a significantly positive impact on the Swedish welfare during a cold spell, and high wind speeds correlates with negative welfare change in areas with much wind power. The fundamental result is that additional redispatch might have a slight positive welfare effect, primarily via a similar mechanism as market integration. The results are based on a quantitative analysis of the simulation data. Although some actors or bidding zones were negatively affected, redispatch provides a viable short-term tool for alleviating grid congestions. While redispatch may have positive welfare impact in the short-term, structural congestions are better alleviated by alternative methods such as bidding zone reconfiguration or other emerging congestion abatement methods. For long-term decisions, redispatch should continue being a second-hand alternative to grid expansion, considering the variable costs and the distortion of locational incentives.

Keywords: *Electricity grid efficiency, Welfare analysis, Remedial actions, Redispatch, Cost-benefit analysis, CBA, Congestion management, Electricity market utility*

Sammanfattning

Flaskhalsar inom och mellan elområden i Sverige och övriga Europa ökar i omfattning och kostnader, framdrivet av bland annat en ökande andel förnybart, ökande integration med angränsande elområden, samt en ökande efterfrågan. Flaskhalsar som uppstår i Sverige löses av systemoperatören Svenska Kraftnät, vars utgifter för flaskhalshantering har ökat kraftigt på senare år. Eftersom nätinvesteringar tar tid förväntas dessa utgifter, som finansieras av flaskhalsintäkter som uppstår mellan elområden, fortsätta vara höga på kort sikt. Det konventionella sättet att lösa upp flaskhalsar är genom att betala producenter i bristområdet att producera mer, oftast över marknadspriset, och samtidigt nedreglera producenter i överskottsområdet som är villiga att minska sin produktion. Trots att mothandel utgör en nödvändig åtgärd för att säkerställa en säker drift har dess välfärdseffekt inte kvantifierats i en svensk kontext. Tidigare studier har påvisat negativ välfärdseffekt av mothandel i Centraleuropa, men dessa resultat kan inte antas gälla för Sverige och Norden. Detta på grund av att Norden har helt andra förutsättningar, bland annat högre andel vattenkraft och regional elområdesindelning. Enligt teorin bör välfärdseffekten av mothandel variera beroende på en rad marknadsförhållanden. Den här uppsatsen undersöker mothandelns välfärdseffekt på den svenska marknaden genom att jämföra EMU från dagen-före marknaden (*dispatch*) med utfallet vid drifttimmen (*redispatch*). På så sätt isoleras effekten av mothandel. EMU är ett etablerat mått på välfärd som används för att uppskatta producenters och konsumenters sammanvägda nytta. Måttet beräknas som summan av konsumentöverskott, producentöverskott, samt flaskhalsintäkter, minus mothandelskostnader. Uppsatsens data baseras på en detaljerad simulering som ENTSO-E gjort över det Europeiska elnätet. Simuleringen antog indata för 2025 års elnät och inkluderade en officiellt godkänd modell. Trots detaljrikedomen antar simuleringen vissa förenklingar av verkligheten, som att mothandeln simulerades på dagen-före resurser, medan det i verkligheten sker på reglerkraftmarknaden och intradagmarknaden. Bedömningen är att metodologins brister kan resultera i en överskattad välfärdsnytta av mothandel. Resultaten baseras på en kvalitativ analys av datat som kommer från simuleringen av ENTSO-E. Det huvudsakliga resultatet visar förvisso att mothandel har en positiv välfärdseffekt i Sverige på +1,3 miljarder kronor för året 2025, men ökningen är endast 0,2% jämfört med status quo. Vidare indikerar resultaten att väderrelaterade faktorer påverkar välfärdseffekten, då extrem kyla korrelerar med positiv välfärdseffekt och blåsväder i södra Sverige korrelerar med negativ välfärdseffekt. Bortsett från att mothandel är ett nödvändigt verktyg indikerar studien att det också kan ge en svagt positiv välfärdseffekt i Sverige i genomsnitt. Det finns däremot goda skäl att behålla mothandel som enbart kortsiktig lösning, på grund av de snedvridna incitament och variabla, osäkra, kostnader som ett högt beroende av mothandel medför. På lång sikt rekommenderas Svenska Kraftnät fortsätta prioritera nätinvesteringar där det är samhällsekonomiskt lönsamt, och förhålla sig till mothandel som ett andrahandsalternativ. Alternativa metoder så som efterfrågansflexibilitet bör även utvecklas för att minska behovet av mothandel.

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Jag tar ansvar för eventuella felaktigheter i uppsatsens innehåll. I take full responsibility for the content of this study.

Edvard Appelberg

Edvard Appelberg

Linköping, 1 July 2025

Det är potentialen att förbättras
som ger spänning i tillvaron

Fritt efter Paulo Coelho, *Alkemisten*

Terminology

Price: If not otherwise stated, price will always refer to daily average electricity spot price (elspot) in this study.

Copper plate model: An assumption that there is infinite capacity on all elements in the electricity grid

Capacity: The transmission capacity refers to the available capacity for electricity transmission after applying a safety margin on the maximum technical capacity to ensure grid security, also called F_{RAM}.

Congestion: Congestion in a transmission line occurs when the dispatched market flows exceed the RAM capacity (Remaining Available Margin) which is the transmission capacity safely available for market use. A congestion may lead to overload and require remedial actions (EP and Council, 2019d, p.12).

Overload: A condition where power flow exceeds the capacity of a grid component (e.g. a transmission line), risking overheating, damage, or automatic disconnection to protect the system. Remedial actions may prevent overloads.

System price: The system price refers to the hypothetical price that would prevail under unlimited transmission capacity (copper plate) in the grid system.

Bidding zone: A geographical area where prices are set based on supply, demand, and net cross-zonal transmission. Some nations have a uniform national bidding zone, others are divided into several bidding zones. Sweden has four bidding zones: SE1, SE2, SE3, and SE4.

Welfare: Defined in this study as the long-term maximisation of utility, considering economic efficiency, environmental impact, and social outcomes (e.g. security of supply).

Actor: The generators and consumers of electricity who buys, sells or generates electricity in the electricity market; a market participant.

EU: The European Union with 27 member states: EU27.

TSO: Transmission System Operator. The company responsible for operating, maintaining, and developing the transmission system for a bidding zone. Svenska Kraftnät is the Swedish TSO. There are 170 regional system operators in Sweden, called DSOs.

Interconnector: A transmission line which crosses a border between bidding zones of two different nations (EP and Council, 2019d, p.12).

Net Supply: Defined in this study as the general level of supply compared to demand. A higher net supply leads to generally lower spot price.

Clearing Price: The day-ahead spot price in a bidding zone.

Excess area: A region where spot price is relatively lower than another area due to comparatively strong internal supply or weak demand (high net supply). If the excess electricity cannot be stored or exported, generation may need to be down-regulated.

Down-regulation: A regulatory measure where the TSO pays a generators in an excess area to curtail, reduce, their generation in order to decrease overload. Although less common, it could also include down-regulating demand, which has the opposite effect.

Deficit area: A region where price is relatively higher than another area due to comparatively weak supply or strong demand (low net supply). Deficit areas rely on imports or flexible generation to maintain a stable frequency. When electricity cannot be imported from excess area, electricity generation may need to be up-regulated.

Up-regulation: A regulatory measure where the TSO pays a generators in a deficit area to increase their generation by paying a (usually) higher price than the market price. Although less common, up-regulating demand may be possible.

Redispatch: A remedial action, initiated by a TSO or DSO to change physical flows in the system and thereby relieve congestion of a particular transmission line, ensuring system stability (EP and Council, 2019c, p.13). Usually realised by up-regulating supply in the deficit area and down-regulating supply in the excess area. This study defines redispatch by including countertrading and curtailment.

Remedial actions: Remedial actions aim to resolve congestions and network security issues (European Commission, 2015, p.29), including methods such as countertrading and redispatching, which are coordinated among TSOs to address both internal and cross-zonal congestion. This coordination aims to enhance capacity allocation efficiency and minimize unnecessary curtailments of cross-border capacities (EP and Council, 2019d, p.13).

Balancing actions: All actions and processes through which the TSO continually ensures a stable system frequency (50 Hz in Europe), and compliance to reserve capacities (EP and Council, 2019d, p.12). Balancing actions aim to address supply-demand imbalance, ensuring constant frequency in the system.

CO2-eq: Carbon-dioxide equivalent units. A standardised measure of the global warming impact of greenhouse gases.

Contents

1 Introduction

The accelerating demand for electricity strains the power grids in Europe, as grid capacity expansions are costly and expected to lag behind a rising demand in the short term. This inertia in the expansion of the grid capacity means that more power is transmitted through the same grid system, leading to congestion when flow exceeds technical capacity. This outlook calls for short-term solutions, like redispatch, that can resolve grid congestions and keep the grid technically stable. Redispatch normally revolves around the Transmission System Operator (TSO) paying suppliers on both ends of the congestion to modify their generation in such a way that the flow returns within technical capacity. Although redispatch is a reliable tool for grid operation, its cost varies with market dynamics and may be expensive for Transmission System Operators.

The Swedish grid system is undergoing a profound transformation, driven by advancing European cross-border market integration and the transitioning away from fossil fuels. Regarding market integration, the European Union's mandatory 70%-rule (EP and Council, 2019c) promotes cross-border transmission between bidding zones, by always reserving 70% of grid capacity for cross-zonal flows. The minRAM spurs market integration, which raises welfare. However, the 70%-rule increases the probability of congestion. These congestions necessitates costly redispatch, potentially undermining the welfare benefits of market integration (Henneaux et al., 2021, p.6). Meanwhile, the Energy transition towards fossil free energy use has also contributed to increasing congestion rates. While non-fossil electricity generation is necessary to accomplish climate objectives, the increasing share of intermittent (volatile) supply requires higher grid capacities, all else equal. This development may continue to cause grid congestion in the short term, as grid expansion takes time.

The Swedish power market has an integral role in the European electricity market. Sweden had the highest electricity generation per capita in the EU in 2023, with 3,317 kWh (Jones et al., 2024, p.78). To increase market integration, the transmission capacity between the Scandinavian peninsula and mainland Europe has expanded in the recent decades. With a growing annual export (33 TWh in 2022), Sweden has a diversified and clean generation mix, consisting of nuclear, hydro, wind, and bio power plants (IEA, 2024a). However, the Swedish grid may face an increasing congestion rate. The rising electricity volume coupled with increasing market integration and intermittent, geographically dispersed, renewables underscores the urgent need for significant grid expansion, and in the interim more redispatch for congestion management. Despite the positive effects of market integration and renewables, the challenge of balancing supply and demand efficiently within the network constraints is imperative, as the electricity infrastructure may be underdeveloped for future needs. The electricity crisis of 2022-2023 raised Swedish redispatch volumes from 26 GWh in 2021 to 363 GWh in 2022 ACER et al. (2024, p.39) or €38 million. The IEA reports that EU congestion management amounted to €4 billion in 2023 (IEA, 2024b, p.259), and it will likely continue rising due to the factors laid out above. While these congestions may be solved by extending grid capacities in the long-term, redispatch provides the conventional interim solution for the short to medium term.

Market integration typically gives a net positive welfare change, associated with efficient resource use. The welfare impact by redispatch, however, includes the highly variable costs of regulating actors to achieve a similar outcome as market integration. Most TSOs finance their congestion management like redispatch and grid expansion via the congestion rent, indirectly paid by consumers (IEA, 2025, p.102), who are less sensitive (less elastic) to price changes than suppliers are (KI, 2024, p.27). Regarding the benefits, redispatch enables more electricity where it is needed, which supports economic activity in the areas that would have had power shortage otherwise. In the EU's effort to promote market integration, the emphasis on reserving 70% of capacity for enabling cross-border capacities may risk outpacing the domestic grid capacities, raising congestion rates. Bucksteeg et al. (2024) finds that redispatch had a net negative welfare change in the Central European grid. If this increased market integration gets too reliant on redispatch, the welfare benefits of market integration may be counterweighed by the welfare effect from redispatching. Moreover, redispatch pays a premium to suppliers where there is a deficit, but also compensates producers in areas with excess power, distorting locational price incentives of the invisible hand of the market. The issue lies in how much redispatch is motivated from a welfare standpoint. While Bucksteeg et al. (2024) find negative net welfare effect from redispatch in Central Europe, the Swedish zonal pricing and net exports reduces the need for excessive redispatch costs, potentially making redispatch net positive for Sweden. However, no detailed welfare analysis of redispatch exists for the Swedish grid. A key question is whether redispatch itself could actually generate positive welfare effects in Sweden, or if it should continue to be used exclusively as a remedial action. The question would be best answered by isolating the effect of redispatch on consumers and producers.

This study quantifies and evaluates the welfare impact of redispatch implemented to alleviate congestions in the Swedish electricity grid.

To evaluate the welfare impact from redispatch, a welfare analysis is applied using data from two simulations on the Nordic electricity market. The reference scenario, *Dispatch*, reflects the day-ahead market outcome, based on ex-ante limits for transmission capacity. The treatment scenario, *Redispatch*, is a re-solve of the day-ahead market with the 70%-minRAM regulation incorporated. In this way, *Redispatch* proxies the actual dispatch at delivery hour, including redispatch actions required to alleviate congestions due to deviations between forecasted and realised transmission capacities. Welfare is measured as Electricity Market Utility (EMU), defined as the net change in consumer surplus, producer surplus, and congestion rents, minus redispatch costs.

The study contributes to the sparse literature on redispatch in the Nordics by analysing welfare impacts using detailed simulation data from the 2025 Bidding Zone Review by ENTSO-E (2025a). While ENTSO-E compare welfare of different Swedish bidding zone reconfigurations, this study isolates the welfare effects of redispatch with a proxy. The entire Nordic grid is modeled in high detail, but the analysis is limited to Sweden's welfare outcomes. It is also limited by the methodolody which assumes redispatch with day-ahead resources, which may overstate the welfare effect from redispatch.

This thesis is conducted on behalf of the Swedish TSO *Svenska Kraftnät*. Although the study is based on the Swedish context, its content may be applicable to electricity markets in similar contexts.

2 Background

The background is quite extensive to give the reader a grasp of how the electricity market operates, and to introduce various relevant factors that may affect welfare impact from redispatch. Relevant insights from previous research are distributed in the background and theory chapter, since the collection of previous studies evaluating welfare impact from redispatch is relatively thin.

2.1 Electricity market structure

Electricity is a unique good, requiring a unique market. First, electricity is a homogenous and non-durable good[1]. As a consequence, supply and demand must be equal at all times to maintain a stable frequency (50 Hz in Europe). Frequency deviations are mitigated by the Transmission System Operator (TSO) by activating balancing actions. Secondly, electricity is a necessary good that many parts of society depend on, making consumers relatively inelastic to price changes (Avramidis, 2024; KI, 2024). This means that taxes and other additives like congestion rent and grid tariffs are mostly born by the consumers, from an economics perspective. Moreover, electricity requires transmission lines to be transported from generators to consumer, which requires that transmission capacity in the grid is sufficient to facilitate the flows. When flows exceed capacity, the TSO needs to activate remedial actions to avoid grid failure. In Sweden, the Transmission System Operator (TSO) Svenska Kraftnät manages the grid to obtain the dual objective to maintain constant frequency and resolve congestions (Svenska Kraftnät, 2025b).

A conventional electricity market design consists of four stages; a forward market, a day-ahead market, an intra-day market, and a balancing market (Energimarknadsinspektionen, 2021). These four markets differ in time frame, function and purpose, but when well integrated and coordinated they enable an efficient electricity market layout. In the European electricity markets, prices are typically set by marginal pricing in each bidding zone, for each hour. This subsection provides an overview for better understanding the context of this study. For a more comprehensive account over the electricity market, see (Le Coq et al., 2025, pp.31-39).

In the day-ahead market, electricity retailers and electricity-intensive industries (consumers) trade electricity directly with electricity generators (Holmberg and Tangerås, 2024, p.19). Each generator (or consumer) enters how much power they expect to generate (or consume) at each hour the following day, and at which price they are willing to sell (or buy). Although bids may be configured in numerous ways in the day-ahead market (Avramidis, 2024, pp.14-15), they all are configurations based on simple bids with a specific price P and quantity Q. Figure A1 in the appendix presents a stylised visualisation of how bids are arranged when calculating market clearing price, assuming there is enough transmission capacity to dispatch all bids that clear in the market. This gives the *system price*, which is the referral price in the forward market (see Nordreg (2016) for details on the Nordic forward markets). The process is illustrated in fig. A3

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[1] The *bathtub model* could illustrate how electrons are indistinguishable in the grid. Just like individual water molecules in a bathtub, individual electrons or kilowatt-hours cannot be traced or distinguished once injected into the system. Therefore, electricity is effectively pooled and priced uniformly in each bidding zone.

in the appendix.

To calculate the spot price, the TSOs first calculate and provide *transmission capacities* that are matched with the market data through the Flow-Based Market Coupling[2] (Energimarknadsinspektionen, 2021). In other words, there is an algorithm which matches bids considering the transmission constraints that the TSO has allocated ex-ante. The TSO would ideally account for potential congestions when allocating capacities. However, the TSO cannot always foresee congestions one day ahead of delivery hour, and too high capacity restraints would dwindle the benefits of market integration (Schönheit, Dierstein, and Möst, 2021, p.1). Given the capacity and bid data, the algorithm returns the optimal physically feasible market clearing prices for all bidding zones simultaneously, rendering the *spot price* for each bidding zone at the day-ahead market closure. Day-ahead is a marginal pricing market, meaning all electricity is traded at clearing price regardless of the bid. All bids below or equal to the market clearing price are dispatched in the day-ahead market. An actor that is not dispatched at day-ahead may bid in the intra-day or balancing market, given that they fulfil the restrictions specified by the TSO.

The intra-day market lasts from the closure of the day-ahead until one hour before delivery (Energimarknadsinspektionen, 2021). In the intra-day market, actors readjust their day-ahead bid quantities either up or down as the delivery hour approaches and various uncertainties clear up (e.g. weather updates or unanticipated failures of grid components). Intra-day is a pay-as-bid market, meaning that supply and demand prices that match are realised at the bid price, which may differ from the day-ahead where price is set by the spot price. In March 2025, European TSOs implemented a 15-minute framework to further facilitate intra-day readjustments, which may resolve some volatility issues from intermittent power, as weather prognoses become more accurate closer to delivery. Note that the annual intra-day volume is a fraction of the annual day-ahead volume: in 2019, traded volume at intraday amounted to 15 TWh, compared to 380 TWh in the day-ahead market Le Coq et al. (2025, p.36).

The balancing markets are managed by the TSO, which may activate balancing resources[3] or remedial actions to fulfil its dual operational responsibility: to maintain a stable system frequency at 50 Hz and to ensure technical grid stability, which includes resolving transmission congestions. Since actual generation and consumption often deviate from the quantities dispatched in the day-ahead market (e.g. due to intermittent renewables, forecast errors, or unexpected outages) TSOs activate balancing resources to correct these imbalances[4]. Depending on urgency and duration, there are several different types of balancing markets Svenska Kraftnät (2025a), each with unique qualification criteria that actors must fulfil to participate. Bids in the balancing market are pay-as-bid, which means that the TSO activates the most cost-efficient balancing resource for its operation.

This study revolves around redispatch, which is a remedial action. This study refers to re-

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[2] In the EU, flow-based market coupling is implemented by European Commission (2015, Article 20). The FBMC is examined and explained by both Schönheit, Kenis, et al. (2021) and Van den Bergh, Boury, and Delarue (2016).

[3] Balancing resources refer to actors participating with bids in the balancing market

[4] When there is excess power, frequency rises. When there is power deficit, frequency drops.

dispatch as an umbrella term for redispatching, curtailment[5] and countertrading, since they all have the same economic effect of reallocating generation to relieve transmission constraints without altering total system demand or supply, see Appendix A.1 for further motivation. As such, redispatch involves up- and down regulating the supply on either end of the congested element without altering grid frequency (unless there is a simultaneous need for both remedial and balancing actions). Although most redispatch occurs at delivery hour using balancing resources, some redispatch is activated at the intraday market by the TSO in anticipation of congestion. Whichever timeframe or market resources are activated for redispatch, in theory the resulting effects are similar to an artificial grid expansion in exchange for a cost, which depends on the redispatch cost. The volume of electricity transmitted is effectively raised for a one-time cost, as if the TSO pays for temporary capacity when there is a congestion.

Considering the dual system responsibility of the TSO, up- and down regulations are activated either for maintaining frequency (balancing actions) or for resolving congestions (remedial actions). Although both balancing and remedial actions can involve the same balancing resources, their purpose differs. Balancing actions address imbalances between total supply and demand, while remedial actions address and resolve transmission constraints, preventing overload and grid damages. At operation hour, the TSOs activate resources based on operational needs and discrepancies between remedial actions and balancing actions are generally not regarded. Redispatch within the delivery hour time frame is referred to as *reactive redispatch*. An alternative method is proactive redispatch, where the TSO allocates lower capacities to the market to avoid overloads at delivery hour.

When looking at the long-term perspective, there are alternatives to remedial actions. Grid capacity is limited by the physical properties of the lines, transformers, and other infrastructure. All else equal, the welfare loss impact from a specific congestion depends much on its magnitude and regularity. Regular or large congestions imply, in general, more consequential welfare loss than infrequent or smaller congestions[6]. Congestions that are predictable, frequently reoccurring and geographically stable over time are referred to as bottlenecks, or structural congestions (Makrygiorgou et al., 2020, p.2). Structural congestions may for example be caused by large supply-demand asymmetry, or a geographical feature that limits infrastructure (dense towns, lakes or mountains for example). Due to economic and regulatory reasons, redispatch is not considered a long-term solution for structural congestions. The most cost-efficient long-term solution to structural congestions is normally to expand the grid because the up-front costs of grid investments are recovered in the long term, compared to relying fully on remedial actions. Conventionally, grid investments would effectively alleviate regular congestions given that the investment bumps up the transmission capacity enough. To read more about grid expansion, see Appendix A.2.

Another alternative is to acknowledge the structural bottlenecks within the nation by reconfiguring the national bidding zones. Having multiple bidding zones in a country provides locational incentives for the market actors. European Commission (2015, Article 32) and EP and Council (2019d, Article 74) emphasise the importance of grid expansion or bidding zone reconfiguration

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[5] Down-regulating renewable supply

[6] However, small and rare congestions may still be costly from a security of supply perspective, for example if transmission to a region with important societal functions or heavy industry is constrained.

to reduce dependence on remedial actions, like redispatch, in the long run. The European TSOs are obliged to evaluate reconfigurations regularly, as "[...] bidding zone borders shall be based on long-term structural congestions in the transmission network [...]" (EP and Council, 2019b, Article 14). Bidding zones also give rise to price differences between the zoned areas, which gives congestion rent to the TSOs. By merit of facilitating the cross-zonal transmission, the owner of the transmission line or interconnector is compensated by the arbitrage, CR, between the two bidding zones, called *Congestion rent*, $CR = F \times (P^N - P^S)$, where $P^N > P^S$ and F is the transmitted quantity. Congestion rent comes from that zones with higher spot price import electricity from lower spot price, creating an arbitrage.

The congestion rent works like a societal welfare benefit, as this money is earmarked for reducing congestions or actions that otherwise benefit the market actors (EP and Council, 2019c), such as grid expansion, bidding zone reconfiguration, or remedial actions (Svenska Kraftnät, 2024a, p.35). This layout intends to contribute to a long-term elimination of structural congestions. However, annual congestion rent is rising rapidly, indicating a delay in the grid expansion. Svenska Kraftnät report a rise from historically being around 2 billion SEK to 21 billion SEK in 2021 and 69 billion SEK from the extraordinary cross-zonal price divergence during the Energy Crisis of 2022 (Diczfalusy and Hellner, 2023, p.64). In the wake of the Energy Crisis 2022, the Swedish TSO distributed subsidies to consumers, in accordance with a temporary EU regulation (Le Coq et al., 2025). As grid expansion may lag behind projected rise in demand and supply volatility, Svenska Kraftnät (2025c, p.40) forecasts congestion rents of over 80 billion SEK 2025-2030. The congestion rent is mostly spent on grid investments in Sweden: the TSO estimates that for every 3 SEK of congestion rent spent on grid investments, 1 SEK is spent on redispatch (Svenska Kraftnät, 2025c, p.41).

Typically, a bidding zone reconfiguration may be necessary when the congestion simply is too heavy and long-lasting to be resolved by grid expansions in a cost-efficient manner. This rationale made Sweden split their uniform pricing into zonal pricing in 2011. An advantage of establishing several bidding zones is that each bidding zone settle prices independently, reducing congestions its associated redispatch costs compared to uniform pricing. The Joint Research Commission (JRC) find that even when the European grid expands 35%, European redispatch would more than triple from 2022 level of 55 TWh. JRC concile more granular pricing to improve price signals JRC et al. (2024, p.32). ENTSO-E (2025a) calculate that splitting Germany-Luxembourg into multiple zones would raise welfare by over €200 million per year. While zonal pricing likely has long-term incentivisation benefits, splitting up a country into several bidding zones involves transaction costs[7] such as time and red tape, and often entails political resistance, see for example the Financial Times article by Virdee (2024) or the article by Müller-Arnold (2025) in Der Spiegel.

Redispatch efficiency depends on partly on how close the regulated generators are to the congestion, topological proximity, as regulating generators closer to the congested element is more effective. When the TSO up-regulates generation in the deficit area, the overload which would have arisen is mitigated. Conversely, down-regulating generation in the excess area reduces the scheduled flows, reducing congestion. Note that, in contrast to balancing actions, the topo-

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[7] In Germany's case, bidding zone reconfiguration may cost 1.2-2.4 billion Euro

logical[8] location within the zone is crucial when redispatching, since redispatching efficiency correlates in general with the topological vicinity to the congested transmission line[9]. When the cheaper and closer generators are unable to match the redispatch need, TSOs may need to activate decreasingly cost-effective regulation. During high needs of redispatch, the costs may increase to an unsustainable level. When the TSO lacks redispatchable resources near the congestion, redispatch becomes less cost-effective, and as a consequence, higher volumes may need to be redispatched resulting in higher costs.

There are alternative short-term remedial actions to redispatch. While some of these solutions may become substantial in the future, they are not opportune with full reliance yet, and therefore not included in the scope of this study. To read about them, see Appendix A7.

2.2 The European electricity sector

Over the past three decades, electricity markets have undergone significant liberalization across Europe, enhancing efficiency and attracting investment in generation and grid infrastructure (Joskow, 2008; Wilson, 2002). In parallel, international electricity market integration has advanced, particularly within the EU (European Union), in effort to harmonize rules and improve cross-zonal trade. Price convergence is a widely recognised indicator of market integration (Corona et al., 2022). Redispatch indirectly facilitates such as convergence by enabling more cross-zonal trade between bidding zones. See European bidding zones in the map in fig. 1. The granularity of these bidding zones varies, but the setup can be categorized into three pricing models: uniform, zonal, and nodal pricing.

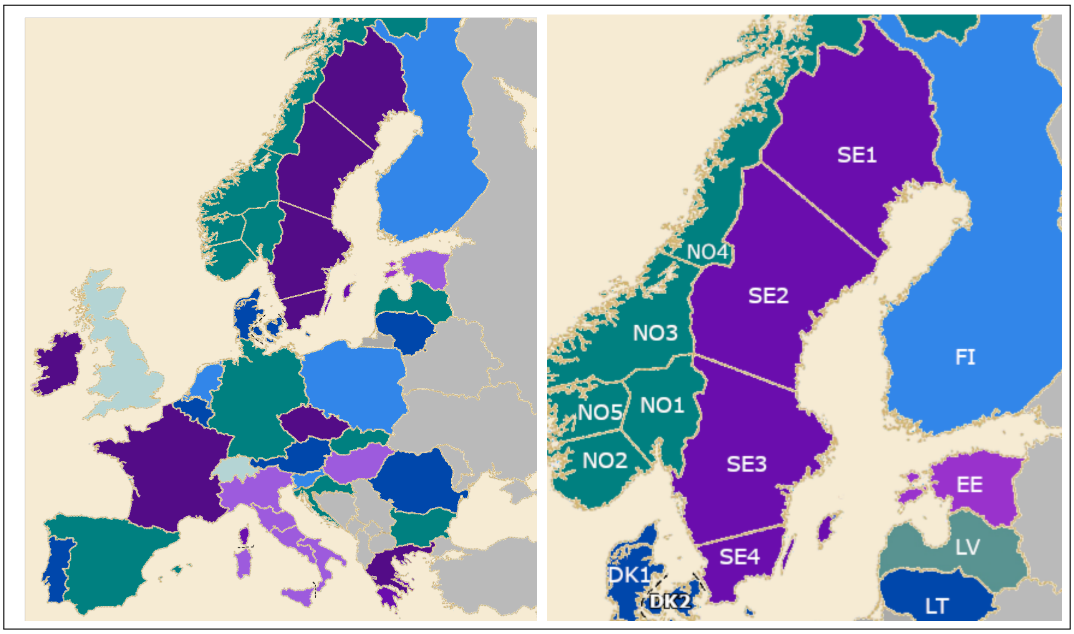

Figure 1: Bidding zones in EU27 & Norway are coloured. Norway implements most EU energy legislation through the European Economic Area (EEA) agreement, and is a member of the internal energy market. The UK and Switzerland are partially involved in the EU electricity market. Edited by the author, based on JRC et al. (2024).

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[8] Topological location is based on the network structure. Two geographically close locations may still be far apart topologically.

[9] With the introduction of Flow-Based Market Coupling, there are exceptions to this.

In *uniform pricing*, all market actors within a country face the same price regardless of location, assuming no congestions in the grid. *Zonal pricing* introduces more granularity by dividing the country into multiple bidding zones, each with its own market-clearing price. This allows prices to reflect broader regional supply-demand imbalances (Dobos et al., 2025, p.1). At the highest level of granularity, *nodal pricing* assigns individual prices at each transmission node, incorporating local supply, demand, and grid constraints.

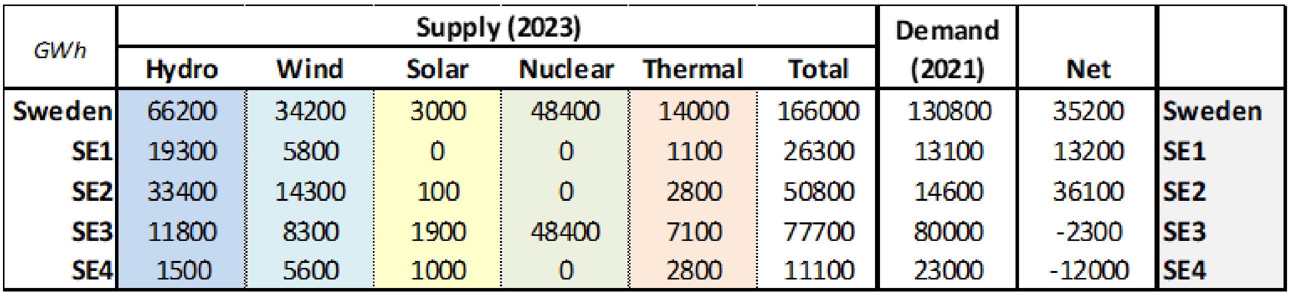
In general, more granular pricing provides more accurate locational price signals to generators and consumers. In a study comparing redispatch to nodal pricing, Dijk and Willems (2011) argue that redispatch under uniform pricing has long-term drawbacks. While it may offer a short-term entry effect, it requires higher grid tariffs and creates adverse entry signals in the long run. The price convergence generated by redispatch implies an implicit subsidy for generators in deficit areas and an implicit tax in surplus areas Dijk and Willems (2011, p.17), distorting investment incentives. More granular pricing aligns regional market signals with regional grid constraints and reduces the need for remedial actions (Dijk and Willems, 2011, p.2).

Despite these advantages, most EU countries retain uniform pricing. As summarised by Eicke and Schittekatte (2022, p.1), there are six main arguments against zonal pricing: susceptibility to market power abuse, reduced flexibility incentives, decreased liquidity (Ehrenmann and Smeers, 2005, p.140), operational complexity, and political resistance to regional price divergence (Holmberg and Tangerås, 2024, p.3). These concerns, along with technical transition costs, such as Germany's estimated €1.2–2.5 billion cost of a bidding zone split (ENTSO-E, 2025a, Annex V), contribute to most European nations remaining with uniform pricing. Despite facing structural north–south congestion, Germany maintains uniform pricing through heavy reliance on redispatch ACER et al. (2024). In 2023, German redispatch costs reached €2.5 billion (Bundesnetzagentur and Bundeskartellamt, 2024, p.24), accounting for approximately 60% of total redispatch costs across Europe (ACER et al., 2024, p.4). Similarly, wind power growth in Scotland has outpaced transmission capacity to the south, raising UK congestion management costs (Bernard and Millard, 2025).

Sweden is one of few EU countries using zonal pricing. Its current four-zone setup (fig. 1) reflects recurring, structural, congestions from north-to-south flows of hydro and wind power in SE1–SE2 to demand centres in SE3–SE4. Internal grid constraints in Sweden, particularly around Stockholm and Uppsala (Sweco, 2020, p.29), have prompted renewed discussions on bidding zone design, notable in various news outlets in Sweden the past years. Sweco (2020, p.29) and Svenska Kraftnät (2021, p.101) identify growing east-west congestion (misaligned with Sweden's predominantly north-south grid) which may explain why SE3 accounted for two-thirds of redispatch costs in 2022 (Energimarknadsinspektionen, 2022, p.13). Svenska Kraftnät (2021, p.101) allocate lower capacities for cross-zonal flows when these flows are projected to ensure operational security. These dynamics indicate there might be need for a new bidding zone reconfiguration. The capacity between SE2-SE3 is one of Europe's largest cross-zonal capacities with 8 GW, although it remains a bottleneck. Table 1 shows that Northern bidding zones are on average net exporting, meaning their internal supply exceeds demand. Meanwhile, internal supply in SE3, the most populous bidding zone, is largely supported by nuclear power. There is also a large amount of thermal power, some of them important for up-regulation.

SE4 only produces half of what it consumes according to 2021 demand. Prices are typically lower in the Northern half, and the price in SE4 often rise with interconnected bidding zones in Europe. As a result, the large surplus of power from SE1 and SE2 is typically transmitted South, to accommodate shortages in SE4 and neighbouring countries. Price divergence has increased despite locational incentives from Sweden's zonal division, highlighting the difficulty of aligning market design with the physical grid.

Table 1: Supply and Demand per bidding zone and generator type. Northern Sweden has a large renewables share and net exporters while southern Sweden has larger share of thermal and nuclear power but are net importers based on 2021 consumption levels. Data from SCB 2025.



GWh	**Supply (2023)**						**Demand**		
	Hydro	**Wind**	**Solar**	**Nuclear**	**Thermal**	**Total**	**(2021)**	**Net**	
Sweden	66200	34200	3000	48400	14000	166000	130800	35200	**Sweden**
SE1	19300	5800	0	0	1100	26300	13100	13200	**SE1**
SE2	33400	14300	100	0	2800	50800	14600	36100	**SE2**
SE3	11800	8300	1900	48400	7100	77700	80000	-2300	**SE3**
SE4	1500	5600	1000	0	2800	11100	23000	-12000	**SE4**

The Bidding Zone Review was published in April by ENTSO-E (2025a), evaluating configurations in Sweden, Germany, Italy, France, and the Netherlands. Although ENTSO-E projected significant welfare gains from implementing zonal pricing in Germany and the Netherlands (ENTSO-E, 2025a, p.8), they found no welfare improvements from any of the four reconfigurations studied for Sweden. Svenska Kraftnät notes other Swedish configurations may still yield benefits. Followingly, in May 2025 the Swedish government comissioned Svenska Kraftnät to assess alternative bidding zone configurations, including evaluating the conditions and implications of implementing a Swedish uniform bidding zone (Regeringskansliet, 2025, p.3), results are due May 2026.

Corona et al. (2022, p.1783) notes that national policies of larger nations like Germany may spill over into neighbours. ENTSO-E (2025a, p.36) project that a German bidding zone split would alter European electricity prices substantially, leading to higher prices in Eastern Europe and lower prices in Northern Europe, including southern Sweden. A study by (Felling et al., 2023, p.98) finds that a bidding zone reconfiguration in Central Western Europe could reduce redispatch amounts by up to 90%, and raise welfare by 1 billion Euro (1.8% of system costs). Dobos et al. (2025, p.10) find similar but distinct configurations as ENTSO-E on Germany, by using k-means methods on publicly available data, but also highlight that optimal zoning changes with time, in line with what the Swedish TSO acknowledged. When comparing the redispatch costs to the welfare effects of a bidding zone split, net welfare outcome is positive from all German and Dutch configurations, just like concluded by (ENTSO-E, 2025a). THEMA (2023, p.2) find that splitting Germany into two parts would reduce redispatch costs by over 60%, but also create price divergence with higher prices in the populous and industrially heavy parts of Germany. They warn that bottlenecks may shift with time, eroding the potential benefits of zonal pricing. This concern is frequently mentioned among scholars and official bodies promoting redispatch.

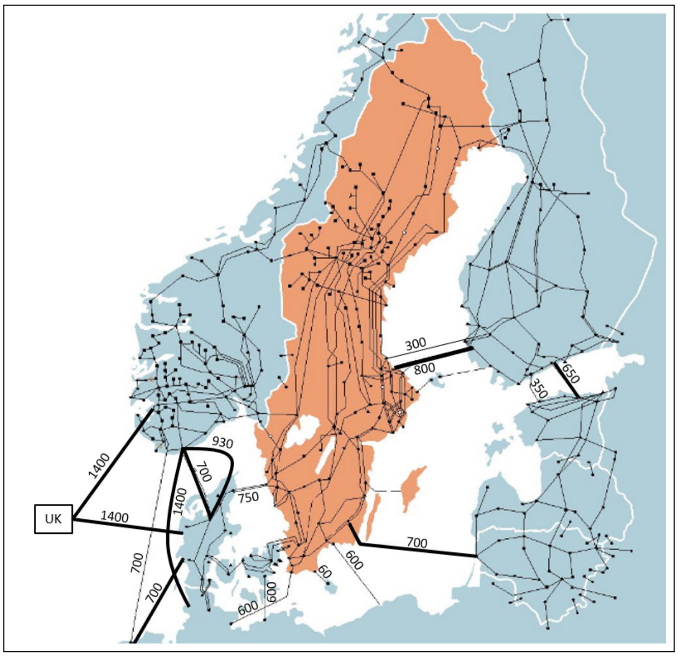


Figure 2: Interconnectors in the Nordic countries and their respective max capacities (MW). The thick dark lines mark all the interconnectors commissioned after 2010. The large expansion of transmission capacity between continental Europe and the Nordics enables higher degree of market integration. Note that there are also AC transmission between nations connected by land. Edited by the author.

Launched in 2014, the European *Single Day-Ahead Coupling* consists of the bidding zones of EU plus Norway, coupling 1 530 TWh per year; over 98% of annual EU electricity turnover ENTSO-E (2024). The common market consists of bidding zones in the EU. Cross border flow of electricity is realised both by land lines and via subsea *interconnectors*, see fig. 2. The map in fig. 1 shows that most countries consist of a uniform bidding zone confined by national borders, though there are a few exceptions. Germany and Luxembourg share a common bidding zone. Norway, Sweden, and Italy are all split into several bidding zones to relieve structural bottlenecks that made it infeasible to maintain a uniform nationwide electricity price without restricting cross-zonal trade (Holmberg, 2023, pp.15-16), which is prohibited unless redispatch is infeasible EP and Council (2019d). The integration of the EU's bidding zones to a single day-ahead market contributes to a more efficient market with better competition, liquidity, and resource use, thereby maximising welfare (ENTSO-E, 2024).

Earlier studies, such as Newbery et al. (2016, p.261) and Uribe et al. (2020), document substantial socio-economic benefits of European electricity market integration; including price convergence and risk sharing. Corona et al. (2022) and Diczfalusy and Hellner (2023) confirm that increased market integration, particularly via reduced cross-zonal constraints, leads to mutual welfare gains. Diczfalusy emphasizes that restrictions to cross-zonal trade would force each country to overinvest in their systems for self-sufficiency, leading to higher total costs. In contrast, integration allows cost-sharing and economies of scale, enhancing both security of supply and affordability across the larger market. Market integration also smoothens price volaitlity. Appelberg and Björklund (2024, p.56) find that the Nordbalt interconnector facilitated price convergence between Baltic and Swedish bidding zones. A news article by Financial Times Thomas (2025) indicate large welfare gains from continued market integration between the UK and the EU SDAC as idiosynchronic net supply shocks can be smoothened out by imports via the interconnectors, like the two lines connecting the UK to Norway and Denmark in fig. 2. However, some countries are voicing concerns that the benefits of market integration are distributed unequally across the EU, as consumers in net importing countries seem to gain more than those in net-exporting regions, like Sweden and Norway. To read more about the European market integration, and its political obstacles, see Appendix A3.

The EU *Electricity Market Regulation* (2019/943) establishes EU-wide rules for the common electricity market, designed to realise market integration and contribute to a more efficient and clean European electricity generation (EP and Council, 2019d). Article 16 (11) prevents TSOs from refusing transmisions that relieve cross-border congestions. Article 18.3 clarifies that TSOs should apply locational price signals to reduce redispatch costs EP and Council (2019d). Article 16 (8) puts a *minimum threshold for Remaining Available Margin* (minRAM) of 70% for cross-border transmission. The minRAM requirement essentially requires all TSOs in the EU to dedicate at least 70% of their cross-zonal transmission capacity for facilitating cross-zonal trade at all times, while accounting for operational security limits and eventual contingencies (i.e. unexpected failures of grid components)(EP and Council, 2019d). The 70%-rule was implemented in intention to promote European market integration, thereby discouraging TSO's from undue discrimination between intrazonal and cross-zonal power exchange[10]. This puts higher pressure on capacity for internal flows.

2.3 Capacity allocation and the minRAM 70%-rule

In this study, 70% minRAM has a central role for the welfare analysis, where the 70%-rule is the treatment between the baseline scenario *Dispatch* and the alternative scenario, *Redispatch*.

Each transmission line has a technical transmission capacity, F_{max}. To ensure grid security, a portion of F_{max} is withheld to comply with the N-1 criterion[11], and a Transmission Reliability Margin (TRM) may be applied to account for forecast uncertainty. These margins ensure robustness to unexpected outcomes. The remaining available margin, F_{RAM}, is the capacity left for market-based flows, both internal and cross-zonal. If market flows exceed F_{RAM} the TSO activates remedial actions to avoid overload.

The minRAM regulation holds that 70% of F_{RAM} is due to be allocated for enabling cross-zonal flows in the day-ahead market, $F_{70\%} = 0.7 \times F_{RAM}$, see fig. 3. This rule applies to grid elements appointed by the ENTSO-E as a *Critical Network Element*, CNE, defined by either of the two following conditions (ENTSO-E, 2025a, p.118):

- Grid elements that connect two bidding zones.
- Grid elements that are important for enabling cross-zonal transmission.

The market is cleared at day-ahead ignoring the 70% minRAM criteria, resulting in F_x which constitutes of some portion of cross-zonal flows ($F_{70\%}$) and another portion of flows that are

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[10] For example, the Swedish TSO restricted cross-border power exchange capacities to Denmark in 2006 to protect domestic consumers European Commission (2010). Actions like these are now only allowed in exemptionary cases, and ENTSO-E will no longer grant exemptionary permissions after 2026 (ACER, 2023).

[11] The N-1 criterion requires that the grid withstand the failure of any single component without compromising system stability.

not induced by cross-zonal trade, denoted F_0. These flows must be accommodated regardless of the capacity allocated to cross-zonal trade. If $F_0 > 30\% \times F_{RAM}$, there is a risk that the total physical flow, $F_0 + F_{70\%}$ exceeds the available capacity F_{RAM}, potentially leading to a congestion, visualised as an overshoot in the figure. Such congestions are typically managed by redispatch. However, as long as the realised cross-zonal flow is lower than 70%, internal flows, F_0, may temporarily exceed 30% of maximum flow F_{RAM} without causing overload. Similarly, non-CNEs are not subject to the 70%-rule, so a larger share of F_{RAM} may be used for internal flows F_0 without risking overload (ENTSO-E, 2025a).

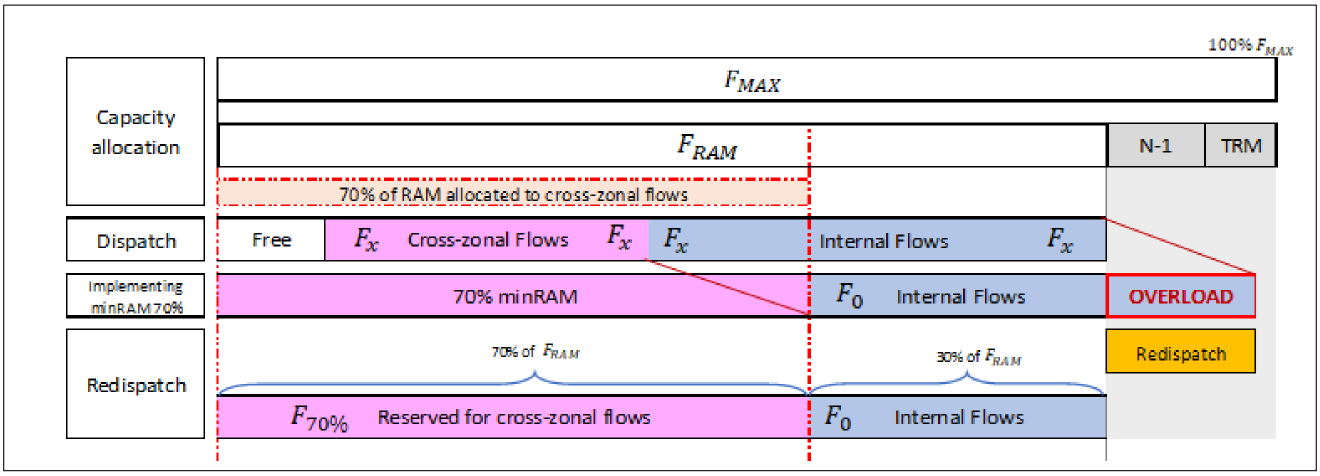

Figure 3: The figure visualises the components of a CNE's loading. In this example, the internal F_0 plus cross-zonal $F_{70\%}$ flows end up exceeding F_{RAM}. The risk for overload necessitates redispatch. Although 70% of RAM is reserved for cross-zonal flows, it can still end up being used to facilitate internal flows. Figure design inspired by Matthes et al. (2019, p.3).

The 70% minRAM requirement was introduced to bolster market integration and unlock its associated welfare gains. Nevertheless, there is typically a redispatch cost associated with these gains when flows exceed the safety margin F_{RAM}. By looking at fig. 3, it is evident that a higher minRAM would result in more frequent congestion in general as the probability of an overshoot increases with the size of the minRAM. Note that this is a stylised explanation and the ex-ante flows, F_0, varies from case to case. In some cases, studies suggest that the 70%-rule may introduce substantial welfare costs, because TSOs rely on redispatch to alleviate potential congestion caused by the minRAM regulation. Simulations on the Central Western European market show that increased market coupling from a higher minRAM can be offset by rising congestion management costs. For instance, Schönheit, Dierstein, and Möst (2021) find that increasing minRAM from 20% to 70% raised total system costs by over 6%, mainly due to redispatch. In contrast, this study would compare a status quo of 0% minRAM to a treatment scenario of 70% minRAM. However, minRAM itself is not the central focus in this study, rather, it serves as a methodological proxy for evaluating the welfare impact of increased redispatch.

The 70% minRAM enforces a constant allocation of capacity regardless of grid conditions. This inflexibility can necessitate costly remedial actions, particularly when redispatch units are far from congested areas (Bucksteeg et al., 2024; Ehrhart et al., 2022). Holmberg (2024) warns that an overly-strict application the 70%-rule could delay investments in cross-border infrastructure. An alternative method based on dynamic regional and seasonal adjustments has been proposed to improve efficiency and reduce redispatch costs (Weber et al., 2023). Similarly, Kenis et al. (2024) argues for replacing the fixed threshold with market-based incentives, that are more adaptive and better aligned with grid realities.

The study by Bucksteeg et al. (2024) resembles this study the most in methodology and purpose. The authors compare the welfare impact from the 70% to the welfare impact of replacing the 70%-rule with *redispatch potentials* in the day-ahead market. To estimate *redispatch potentials* they implemented a multistage model which accounts for capacity allocation, market coupling, and redispatch phase. Comparing redispatch potentials to the 70%-rule, *redispatch potentials* rendered a higher welfare benefit of over +€100 million, but it decreased market integration by -20TWh. Whereas minRAM promotes market integration welfare gains, it also imposes redispatch costs that may erode these gains. The trade-off between market integration and redispatch costs is repeated in several studies, including Matthes et al., 2019 and Henneaux et al. (2021). In a discursive study on redispatch and market coupling, Oggioni and Smeers (2013, p.86) express that their simulations show that an accurate trading capacity allocation can make market integration more efficient than nodal pricing. However, "a too high or too low [F_{RAM}] degrades welfare". They conclude that the issue is to select the right F_{RAM}, "a question that remains, and probably will remain, unsolved". This study does not explicitly explore the effects of 70% minRAM, but it does explore the welfare impact of redispatch, which is mostly induced by the 70%-rule. According to ENTSO-E (2025a), about 90% of congestions in Sweden arise due to the 70%-rule in the data of this study. The impact from the minRAM 70%-rule may be indicative of how additional redispatch affects welfare, in general. From this perspective, the 70% rule may proxy additional redispatch.

2.4 The Energy Transition may exacerbate congestions

The electricity sector stands for over a fourth of global CO2-eq emissions (IEA, 2024b, p.121). With such a large impact, global climate change mitigation relies much on the progress of the Energy Transition in the global electricity sector. To mitigate the future risks and costs associated with climate change, EU and its member states have established numerous regulations and commitments in the area. More information about climate change related commitments that affect the European electricity markets is presented in Appendix A4. Overall, this development leads to increasing share of renewable generators. The share of fossil-based electricity in the EU shrank from 48.8% in 2010 to 39.2% in 2022, replaced by a growing share of intermittent power sources like wind and solar. While the rising share of renewables may mitigate climate change, it also correlates with increasing grid congestion according to previous studies.

There are two major drivers for increased grid congestion from the ongoing Energy Transition, documented in statistics as well as previous studies:

1. Increasing supply intermittency. As European countries have strived for renewables, the overall share of intermittent, weather-dependent, electricity has increased. Meanwhile, in many European countries including Sweden, the UK, and Germany, baseload generation from nuclear and coal have been decommissioned and shut down. The resulting overall trend is a major shift from baseload to intermittent power generation. The replacement of stable baseload generation with intermittent renewables has contributed to more frequent

congestion (Van den Bergh, Couckuyt, et al., 2015, p.22) and imbalances. These congestions need to be resolved, resulting in increasing costs for redispatch and curtailment (down-regulating renewable supply) raising costs in many European power systems. To avoid overloads, down-regulation is typically done by curtailing renewables at the excess area, as they provide cheaper bids for curtailment than fossil-based generators. In 2023, about 4% of German renewable electricity generation was curtailed (ACER et al., 2024, p.4). At the deficit area, up-regulation is typically realiosed with high merit order generation from fossil-fuelled power plants. In 2023, 62% of up- and down-regulation in the EU was met by fossil-based generation, underscoring the environmental costs of increasing congestion and balancing needs (ACER et al., 2024, p.51).

2. Geographical mismatch between generaion and consumption. The deployment of wind and solar generation clusters where their potential is maximised increases the risk that the transmission infrastructure has insufficient capacity to transmit electricity to demand centres (JRC et al., 2024, p.5) (Elia, 2019, p.9) (Felling et al., 2023). Many wind and solar power generators locate where land prices are low (Ehrhart et al., 2022, p.1), which tends to be farther away from population centres (Elia, 2019, p.9). For example, in Sweden the intermittent generation has grown mostly in northern bidding zones SE1 and SE2, far away from critical demand centres in the southern SE3 and SE4 (Svenska Kraftnät, 2024c). All else equal, longer distances between generaion and consumption requires more infrastructure for the same power, making the grid prone for congestions. Large north-south assymmetry in net supply is also prevalent in the UK (UK Energy Security, 2024, p.16) and Germany (THEMA, 2023). Corona et al. (2022) attribute rising cross-zonal congestion in the Central Western European region partly to the growing share of renewables in Germany's generation mix. IEA (2024b) points out the municipal veto right against wind mills as an impediment to wind generation in Southern Sweden, causing geographically uncoordinated deployment of supply to demand centres (IEA, 2024b, pp.54-55). Geographical mismatch also gives rise to loop flows and unplanned power movements, complicating cross-zonal congestion management (Elia, 2019; Kunz and Zerrahn, 2016). Another significant impediment is that building power infrastructure is particularly expensive in urban areas (Holmberg, 2022, p.19). Implementing locational incentives is promoted by Article 23 in 2019/943 (EP and Council, 2019d), and also endorsed by IEA (2024a, p.55) as one of 10 policy recommendations for improving the Swedish grid system. Energimarknadsinspektionen are currently looking for ways to incentivise generators to locate their plants closer to consumers Energimarknadsinspektionen (2024, p.15).

The combined effect of geographical supply-demand mismatch and increasing supply intermittency puts significant stress on the European grid systems, since it tends to require higher capacities and more balancing service for the same amount of power for the same amount of electricity. The JRC et al. (2024, p.3) find that "this uncoordinated deployment will massively increase the need for redispatch". Redispatch volumes in the EU may increase almost sixfold, costing between € 11-26 billion in 2030 compared to €5.2 billion in 2022 (JRC et al., 2024, p.5), given that bidding zones remain as today. ACER et al. (2024, p.52) estimate that curtailment of renewables amounted to 12 TWh in 2023, causing an additional 4.2 million tonnes of CO2-eq emissions. Putting its benefits aside, the Energy Transition has caused increasing costs for balancing and redispatch, and may continue to do so. This trend is exacerbated by delays in planned grid expansion projects, which further constrain transmission capacity and amplify the need for redispatch (Frysztacki and Brown, 2020).

2.5 Economic significance of redispatch

Virtually all economic activity involves some level of energy or electricity usage, either directly or indirectly. Therefore, rising costs in the electricity system may cause real economic harm, as energy prices are fundamental drivers of inflation (IEA, 2024b, p.73). Figure 4 breaks down inflation by cause, showcasing a clear example of energy prices driving inflation during the Energy Crisis of 2022. The crisis was initiated by the gas and oil price surge following the Russian invasion into Ukraine in 2022, and exacerbated by low precipitation and nuclear maintenance works across Europe (Le Coq et al., 2025, pp.54-60). Since there is a certain degree of substitutability among energy commodities, the high gas & oil prices had wide impacts on electricity prices (IEA, 2022, p.277). A study by Sgaravatti et al. (2025) reveals that around €800 billion was spent to shield households and firms from the Energy Crisis, every nation experienced energy price surge, but the protective policies differed much from nation to nation (Le Coq et al., 2025, p.58). Prices surged the most in countries with high gas dependence and high supply reduction. Sweden, however, with a low dependence on fossil fuels, had the lowest electricity prices in Europe in 2022 and emerged as the largest net exporter in Europe (Le Coq et al., 2025, p.56)(Nord Pool, 2025).

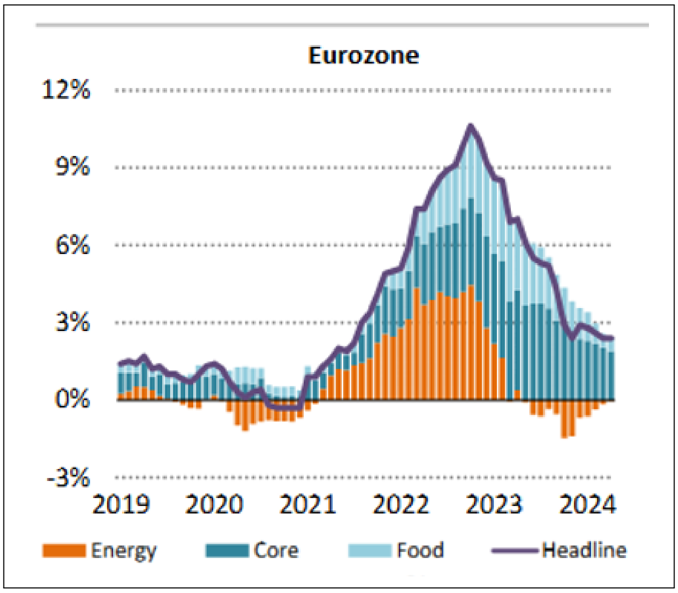

Figure 4: Inflation drivers in the Eurozone. This graph shows the significant impact of energy prices on the wider economy.

After decades of stagnant electricity consumption, projections by Svenska Kraftnät indicate a doubling of Swedish demand from 135 TWh in 2024 to between 280-365 TWh by 2030 (Svenska Kraftnät, 2024b), in line with the global trend of a doubling of demand by 2040 compared to 2010 (IEA, 2024b, p.123)[12]. In Sweden, industry decarbonisation underpins the majority of

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[12] The expected surge in global demand is based on a range of macro-trends (IEA, 2024b, p.39-44), including the proliferation of datacenters, electricity substitutes to replace transport fossil fuels, and rising air conditioner

projected additional demand (IEA, 2024a, p.40). In anticipation of this, the International Energy Agency (IEA) identifies grid and system expansion as Sweden's key challenge. In spite of investing heavily in grid reinforcement, the European TSOs may face difficulties ramping up their grids to match the fast growing electricity demand, which means that the impending demand growth may contribute to grid congestion. The cost and volume of remedial actions in Sweden are already rising, mirroring wider European trends. In 2022, the reported volume of remedial actions in Sweden rose to 363 GWh, up from just 26 GWh in 2021 a fourteen-fold increase, largely driven by increased redispatch between Swedish bidding zones to manage congestion (ACER et al., 2024). On a broader scope, the total cost of remedial actions in the EU reached €5.2 billion in 2022 (a 45% increase from 2021) with Germany accounting for over half of total redispatch volumes. Official bodies expect Swedish net exports to remain or increase given the large net supply of about 30 TWh per yearSvenska Kraftnät (2024c) and the comparative advantage of low-cost renewables in the Swedish electricity mix (Diczfalusy and Hellner, 2023).

In their regional insights about Europe, IEA (2024b) emphasize heavily on the urgency of expanding grid capacity, while also acknowledging the importance of European market integration. The following citation may describe the current European, and Swedish, challenges comprehensively:

> "The expansion of renewables will not do much to lower overall electricity costs if [renewables] cannot be successfully integrated into electricity systems. Grid congestion and redispatch costs, which hit EUR 4 billion in 2023, are expected to rise, underlining the crucial need to invest in grid infrastructure and to expand interconnections (ACER, 2024). The investment required is necessary to unlock the benefits of renewables and would be offset by the savings gained from reduced fossil fuel imports. Delays in investing in the necessary grid infrastructure and the provision of flexibility are all too likely to result in increased congestion and [volatile prices]. Over time, this could undermine generators' revenues and overall security of supply. Further European Union electricity market integration would also help to foster integration of renewables, ensure reliable supply and mitigate price differences between bidding zones" (IEA, 2024b, p.259).

As explained, the welfare benefits of the Energy Transition and market integration depend much on the grid capacity. Thus, in long term the TSOs grid investments, and in the interim the TSOs congestion management, play a decisive role for the overall efficiency of the European electricity sector[13], where Sweden plays a key role. As European grids are in large part under-dimensioned for the near future, a solid strategy for congestion management is crucial. Redispatch, when used in moderate magnitudes, ensures reliable supply by decreasing congestions in the short run. This study contributes to understanding how congestion management by redispatch affects welfare outcomes.

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use (IEA, 2025, p.22). The electrification of heavy industries, particularly through hydrogen production, may also become a driving factor (IEA, 2024b)

[13] Additionally, supplementary solutions such as demand-side flexibility and power electronics solutions should play an increasingly important role to improve overall performance of electricity grid systems.

3 Theory

This section introduces the theoretical foundations relevant to electricity market dynamics, welfare analysis, and cost-benefit assessment, with a focus on redispatch.

3.1 Welfare in the electricity market

In economic theory, electricity is a consumption good that generates utility. As long as the utility of additional electricity is valued higher than the electricity costs, additional electricity adds net positive utility (welfare) to the individual. Welfare includes social, economic, and environmental aspects. See Appendix A5 for established context. However, this study concerns a welfare analysis that only captures the welfare effects incorporated into the market. Below, fig. 5 illustrates a stylised graph of supply and demand in the electricity market. According to welfare theory, welfare for producers and consumers is defined by *Producer surplus* (PS) and *Consumer surplus* (CS), respectively.

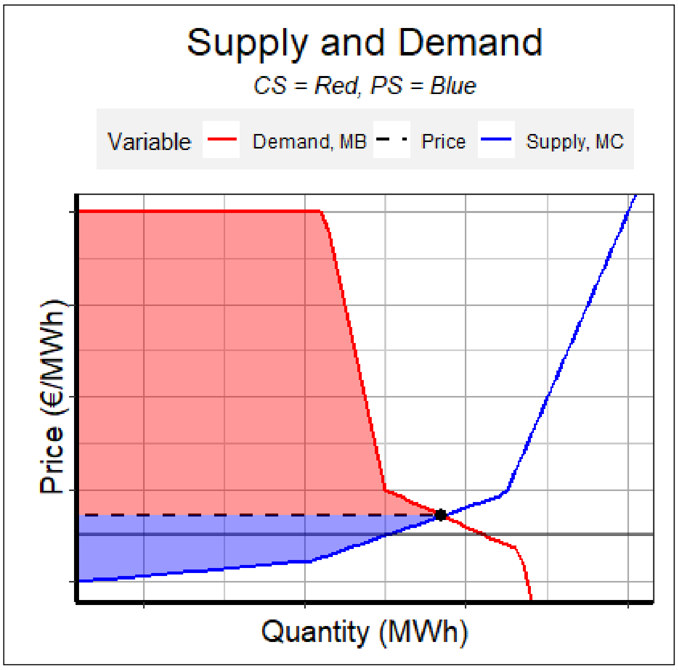

Figure 5: Stylised supply and demand curves. The blue area corresponds to the producer surplus, while the red area corresponds to consumer surplus. The curves are inverted, with price on the y-axis.

The producer surplus is graphically confined by the area between price P_E and the supply curve $S = MC$ (Hultkrantz and Vimefall, 2020, p.51). The aggregate producer surplus is the revenue minus costs, $P_E * Q_E - TC$, see fig. 5. In a marginal price-setting market like the electricity market, producers (generators) place their selling bids at their true marginal cost[14] MC. For example, hydropower plants always have the opportunity to withhold their water in their hydro reserves for generating more power when prices are higher. Due to this opportunity cost, hydropower generators may regulate their generation to maximise profit over time. Another example is that renewable generators supported by subsidies afford to bid below

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[14] In reality, it is the marginal opportunity cost, i.e. their marginal generation cost plus any other indirect or intangible costs.

their marginal generation cost since the subsidies may cover the losses. In summation, the bids do not only rely on MC but also include the marginal opportunity cost of generating electricity.

The consumer surplus is graphically confined by the area between the price P_E and the demand curve $D = MB$ (Hultkrantz and Vimefall, 2020). The total consumer surplus is the perceived marginal benefit minus the costs $MB - P_E * Q_E$. In a marginal price setting market, consumers put their buying bids at their perceived marginal utility of electricity (MB). Marginal benefit incorporates how much the additional electricity is worth in monetary terms, also including the opportunity costs such as the cost of substitutes to the electricity if they are not dispatched. Since consumers reflect their benefit when submitting their bids, it follows by revealed preference theory that the consumers' bids reflects their estimated (marginal) benefit of electricity.

To clarify, both consumers' MB and producers' MC account for monetary and non-monetary (opportunity) costs. Consumers whose bids deviate from their MB are either paying more than they value the electricity, or run the risk of not benefitting from a price they would have accepted. Likewise, producers who bid above their MC risk not being dispatched at a clearing price they would have profited from, and bidding below MC has no comparative advantage over bidding at marginal opportunity cost, as it would risk incurring losses. In a perfectly competitive electricity market, bidding at MC and MB constitutes a Nash equilibrium. While actors may sometimes deviate for strategical motives, the Nash equilibrium provides a principal outset. Given that the supply curve reflect MC and that demand curve reflects MB, the equilibrium marks the clearing price, where no dispatched actor has negative surplus. In these circumstances, the clearing price it is Pareto-efficient[15] Hultkrantz and Vimefall (2020, p.32).

Demand is relatively inelastic to price changes. In most countries, the price elasticity of demand ranges between -1 to 0 for both households and firms (KI, 2024, p.27), meaning that a 1% unit change in electricity prices leads to a less-than one percentage unit opposite change in quantity demanded. In Sweden, short term price elasticity of demand is around -0.5%. However, note that the elasticity tends to be more elastic in the long run as consumers may be able to switch to other energy sources for some purposes (heating, transport, cooking, etc.). While efforts are underway to increase flexibility among consumers, see (Energimarknadsinspektionen, 2024), much demand remains relatively inflexible. One reason is that a large share of households lack incentives to change consumption as hourly spot price change because their electricity price is fixed at monthly or yearly averages (Le Coq et al., 2025, p.33). Another reason is that the cost of not having electricity (the opportunity cost) is very high. However Avramidis (2024, p.63) find that high-bidding consumers might overstate their true marginal utility of electricity when bidding since they expect the (much lower) clearing price. The results indicated consumers revise their value of electricity during crisis, leading to lower bids (Avramidis, 2024, pp. 8, 44).

Extreme price events often occur when the steep sections of the supply and demand curves intersect. As illustrated in fig. A1, small shifts in supply or demand near these points can cause disproportionate price movements. When supply tightens, demand may hit the steep section of the supply curve, causing extreme prices in both day-ahead and for redispatch. The term *Dunkelflaute* refers to periods when low wind and solar power generation coincide with high demand (typically cold winter days) creating vulnerability to price spikes (Millard, 2024). In

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[15] No actor can be made better off without making another actor worse off

principle, electricity storage technologies (batteries, pumped hydro, hydrogen) could mitigate this, but technical and economic constraints remain. In such circumstances, Sweden's dispatch decisions become more consequential, especially for redispatch and congestion management.

3.2 Congestion Management

Grid congestions may be intuitively understood through an analogy to fluid mechanics. According to Kirchhoff's law, in general, electricity flows in the path of least resistance. Just as water flows through a network of pipes from high pressure to low pressure, electricity flows through a network of lines from high voltage to low voltage. In both cases, when the flow becomes too large, the system faces constraints as water pipes may burst when water flow exceeds pipe capacity, just as power grids may become overloaded when electricity flow exceeds the Remaining Available Margin (F_{RAM}) for transmission capacity[16]. Left unmanaged, grid congestions would cause disruption and prevent electricity from being transmitted causing large economic damage. Therefore, remedial actions like redispatch is necessary.

To illustrate the welfare effects of redispatching, it may be useful to start with the effects of increased transmission capacity (i.e. electricity market integration). After that, the effects of redispatch can be presented in a pedagogical manner. Given that redispatch involves up- and downregulation of supply, the theories presented here assumes redispatch exclusively on the supply-side (generators). Transmission losses are ignored for simplicity.

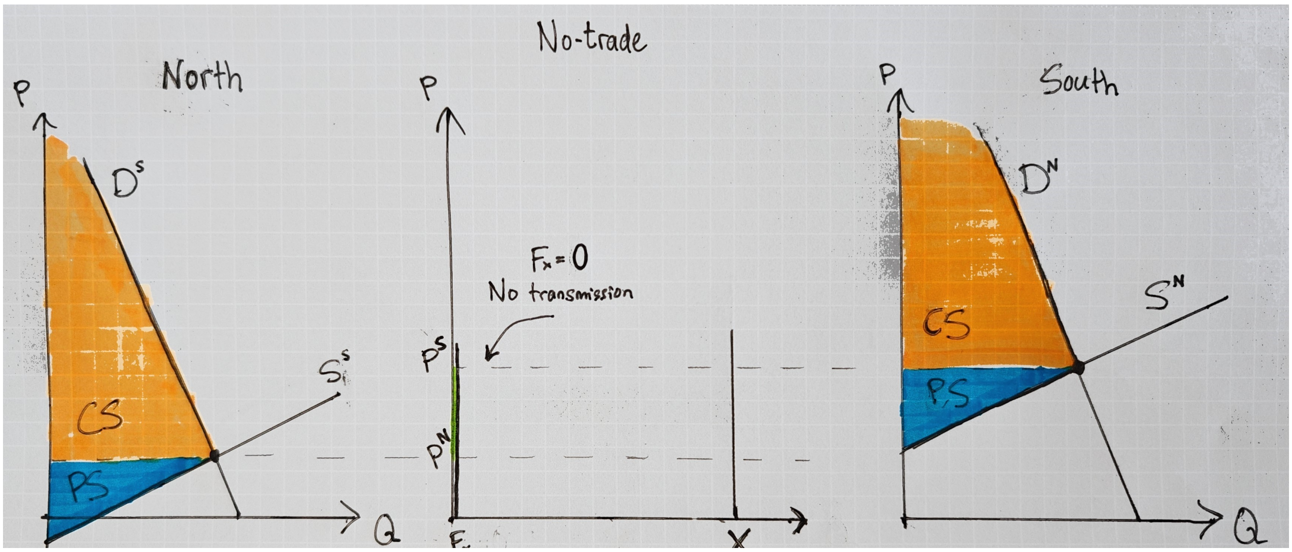

Figure 6: No-trade model. This model illustrates the total welfare assuming zero transmission capacity. Consumer Surplus in orange, Producer Surplus in blue.

Assume there are two areas, either bidding zones or nodes within a bidding zone. When comparing their relative supply, one is comparatively deficient in electricity (South) leading to high prices, while the other one has comparative excess of electricity leading to lower prices (North). Figure 6 shows a no-trade scenario, when there is no transmission between North (left graph) and South (right graph). Without transmission, the day-ahead clearing prices would settle at P^N in North and P^S in South. Consumer and producer surplus are marked as CS and

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[16] It is in fact the thermal distresses of overload that determines transmission capacity.

PS in orange and blue respectively. The middle graph visualises transmitted quantity and the resulting Congestion Rent (CR). Given the day-ahead bids, an amount X MW would need to be exported from North to South for full price convergence. The actual flow in denoted by F_x. By analogy with trade economics, transmission flows are referred to as imports and exports for clarity and pedagogical convenience.

At the day-ahead dispatch, TSOs calculate and allocate ex-ante capacities to each transmission element. Just like explained in Figure 3, these capacities ensure a market efficient flow at dispatch, but do not necessarily reflect the feasible outcome at delivery hour, F_{RAM} because it does not account for $F_{70\%}$, or any unforeseen grid failures and forecast errors. In a utopian grid system, every grid component would have infinite capacity, thereby eliminating all congestions and needs for remedial actions, making $X < F_{RAM} \equiv \infty$. The concept of unlimited transmission capacity is called the copper plate model, framed in fig. 7. If North and South are nodes within the same bidding zone, the exports F_x from North to South has to be equal to X MW. This is because all nodes within a bidding zones are assumed to be in full price convergence, as illustrated in fig. 7. The bidding zone's clearing price P^E is settled in both South and North, leading to X MW being transmitted. Surplus transfers are marked blue and orange. The resulting net welfare change from market integration is positive, marked by the stripes.

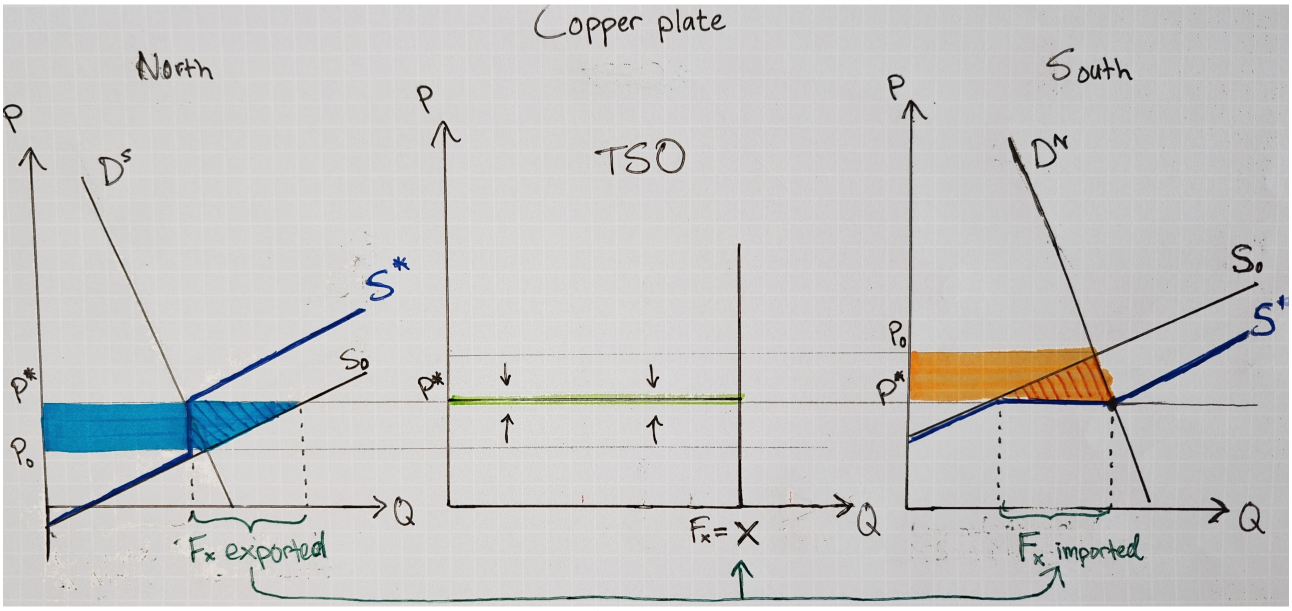

Figure 7: The copper plate model assumes infinite transmission capacity F_{RAM}. This results in full price convergence: $P_0^N < P^* = P^* < P_0^S$, and therefore zero congestion rent. Generators in North gain producer surplus partly from higher prices and partly from the exports, marked in stripes. In South, consumers gain surplus partly from lower prices and partly from the imported electricity.

On the other hand, if North and South are in two separate bidding zones, the prices are allowed to differ. If F_x is enough for full price convergence ($F_{70\%} \geq X$) the day-ahead outcome is equivalent to fig. 7. However, in all cases where $F_{70\%} < X$, the outcome is illustrated by fig. 8. The figure shows a partial price convergence, with market integration welfare effects partially realised. An important detail is that this partial convergence results in congestion rent, equal to price difference multiplied with exports. The congestion rent has a concave (inverted U-shape) relation with F_x, as it first grows from higher exports and then shrinks as the price difference dwindles. This can be seen by increasing and decreasing F_x in fig. 8.

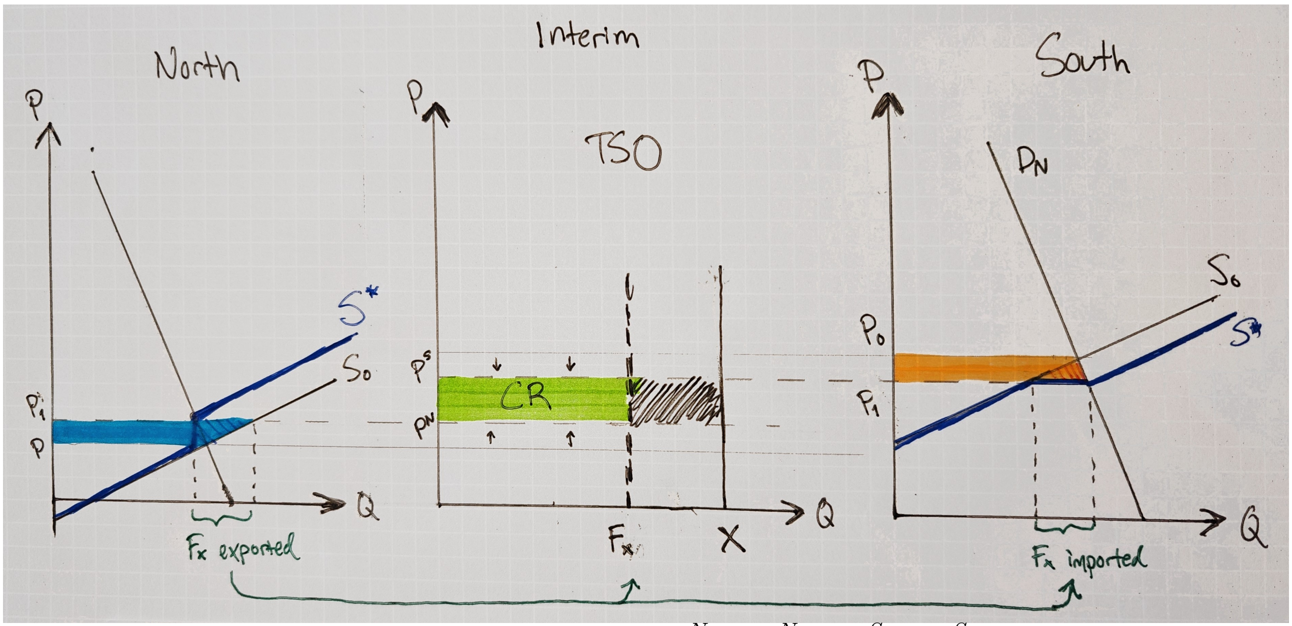

Figure 8: If F_x leads to partial price convergence; $P_0^N < P^N < P^S < P_0^S$, a congestion rent arise, marked in green. The effects on CS and PS are similar to the copper plate outcome but lesser in magnitude.

The theory suggests net welfare gains from market integration, just like earlier studies and official bodies suggest. On aggregate, in North surplus transfers from consumers to producers. In South, surplus transfers from producers to consumers. Imagining North is SE2 and south is SE3, higher transmission capacity would lead surplus to be transferred from consumers to producers in SE2 and vice versa in SE3. However, mind that no area or bidding zone is always the excess area, as the excess and deficit area roles switch each time the relative prices switch. The net welfare gains are demonstrated by the additional electricity made available via market integration in striped colours. Some marginal producers in North that were excluded from dispatch in no-trade gain surplus from exported quantity. Likewise, marginal consumers in South gains surplus from the imported quantity. In this study, the outcome is referred to as day-ahead *dispatch*. After this point, the (spot) prices and quantities are fixed.

So far, theory suggests that market operators should strive for extending capacities to maximise welfare, approaching the copper-plate model. However, while structural and long-term congestions are best alleviated by grid expansion or bidding zone reconfiguration, irregular and minor deficiencies of transmission capacity may be better managed ad hoc by redispatch; building out capacities to prevent inconsequential congestions is superfluous and therefore welfare inefficient[17](Newbery, 2023, p.34).

The following theory illustrates the welfare impact from redispatch actions, central to this study. Given the day-ahead dispatch flows F_x, a congestion may arise due to the total flow $F_0 + F_{70\%}$ exceeding the F_{RAM}. The resulting congestion is illustrated in fig. 9 and fig. 10, where planned flows exceed the F_{RAM} by C MW and the red zig-zag line marks the imminent overload. Regardless of whether congestion arises within or between bidding zones, the TSO is responsible for ensuring that dispatched quantities are physically feasible, so any congestion

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[17] Keep in mind, though, that capacity surplus and redundancy can in certain cases serve a security of supply purpose. Future scenarios may also justify grid expansion where the TSO expects congestion to increase.

that emerges requires remedial actions such as redispatch.

3.2.1 Within a bidding zone

When physical congestion of an amount C MW arises within a bidding zone after market clearing, the congestion rent changes to reflect the feasible quantity exported and imported (fig. 9). To resolve the congestion and accommodate the dispatched bids, the TSO activates generators on the balancing or intraday market. The cheapest available bids from the balancing and intraday market can be visualised in the right and left graphs, where the TSO activates C MW for both up- and down regulation to keep frequency intact. The redispatch cost of up-regulating C MW in the deficit area depends on the merit order of available bids, but could be roughly represented as $P_n^{UR} = MC_n + \mu_n^+$, where μ_n^+ reflects the specific markup for each generator n to offer the balancing resource and the price for up-regulation is usually higher than the spot price ($P^{UR} \geq P^*$). On the other end, the cost of down-regulation in the excess area may be lower, particularly if zero or low marginal cost generators such as hydro, wind, or solar are available which is often the case in Sweden. Redispatch costs for down-regulation is $P_n^{DR} = MC_n + \mu_n^-$, where μ_n^- again represent mark-up, but upregulation is generally more expensive $\mu_n^- > \mu_n^+$. A list of the markups is provided in table A1. The consumer surplus gain consists of the selling price P_n^{UR} or P_n^{DR} minus marginal generation costs MC_n.

The results is that the TSO pays $\sum_n^N UR_n * P_n^{UR} + \sum_n^N DR_n * P_n^{DR}$ for redispatch, and the producer surplus increases by $\sum_n^N UR_n * \mu_n^+ + \sum_n^N DR_n * \mu_n^-$, where the total up- and down-regulation adds up to C; $\sum_n^N UR_n = \sum_n^N DR_n = C$. Note that prices are unchanged and congestion rent remain at zero.

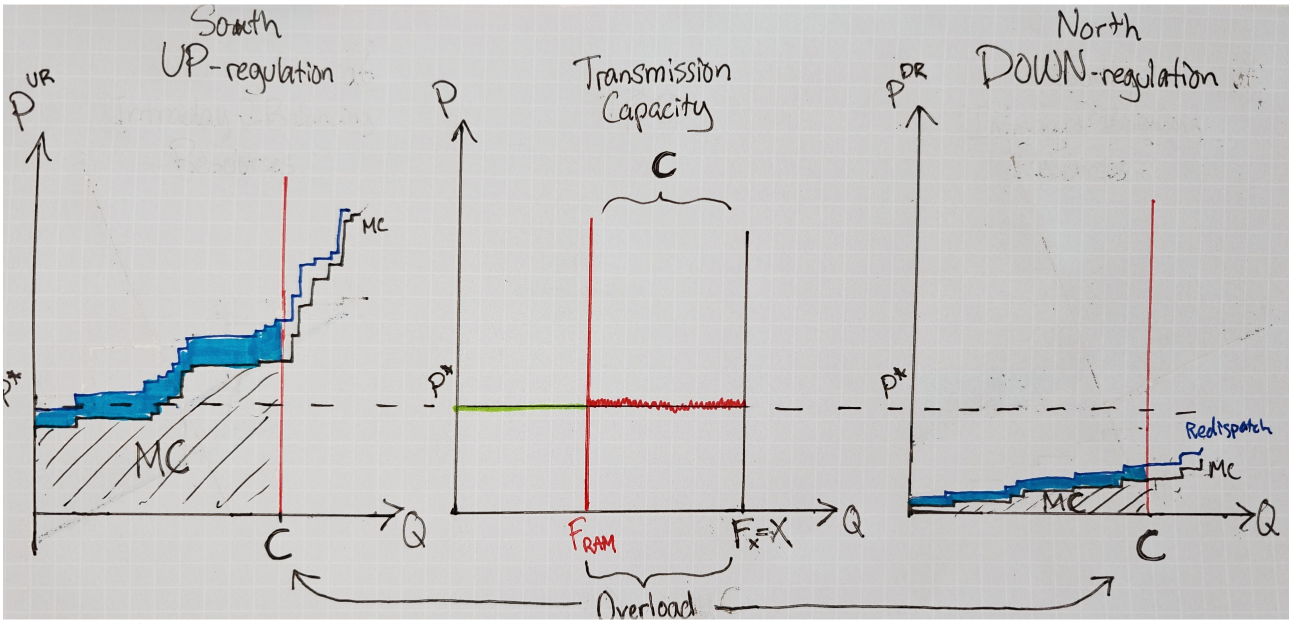

Figure 9: A congestion of C MW would lead to redispatch costs represented by the blue area plus MC area. Producers would gain some surplus based on the markup marked in blue.

3.2.2 Between bidding zones

If there was a price difference at dispatch, as in fig. 8, the outcome is in large parts identical to fig. 9, the only difference being that there is also a change in congestion rent, seen in fig. 10.

As noted, these graphs are stylised and represent the general theory.

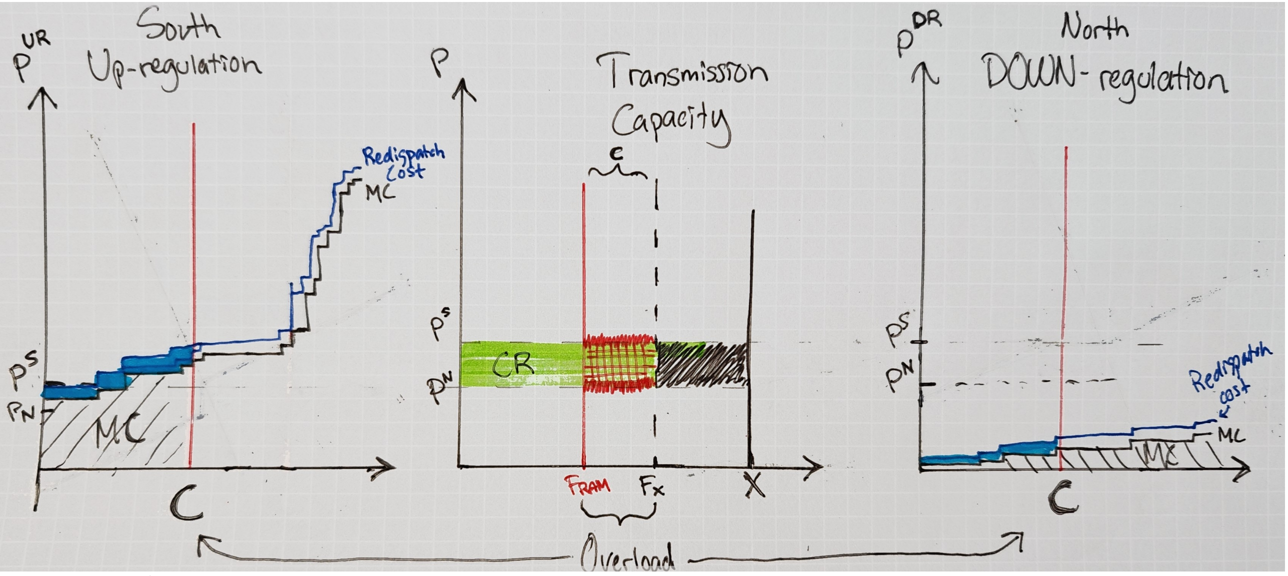

Figure 10: A congestion of C MW leads to similar effects as in the previous figure, but congestion rent typically fall. In reality, optimisation by market based coupling could sometimes lead to increased congestion rent after redispatch, due to counter-intuitive flows.

Mathematically, the four welfare components are defined by the following equations, based on ENTSO-E (2025a).

$$PS = (P * Q - \sum_{n=1}^{N} MC_n * Q_n) + (\sum_{n}^{N} UR_n * \mu_n^+ + \sum_{n}^{N} DR_n * \mu_n^-) \tag{1}$$

Producer surplus consists of a core term, marked by A in fig. 10, plus the surplus that comes from the markup costs for the redispatched generators, represented by UR and DR. The core term is the traditional consumer surplus, subtracting each generator's cost for generating their dispatched quantity, $MC_n * Q_n$, from their revenues $P * Q$. The redispatch term captures the total surplus from down-generation, where D_n MW is down-regulated at each generator n and U_n MW is up-regulated. Based on the formula, a congestion causes a drop in core term surplus in the excess area that is partly compensated by the markup the down-regulated generators receive. Meanwhile, deficit areas would gain producer surplus from up-regulation. These effects are scaled with the amount C MW needed to redispatch.

Consumer surplus consists of a core term, obtained by summing up the marginal benefit MB of each consumer n times their supplied quantity, before subtracting total costs $P \times Q$. A redispatch term is omitted since the methodology of this study assumes consumers do not participate in redispatch.

$$CS = \sum_{m=1}^{M} MB_m \times Q_m - (P * Q) \tag{2}$$

Congestion Rent is calculated by taking each pair of connected bidding zones e and d, and multiplicating the price difference $P_d - P_e$ with the quantity transmitted $F_{e->d}$. The expected outcome from redispatch is that congestion rents fall; not due to redispatch, but due to the preceding congestion making it infeasible to transfer the amount that was projected at dispatch.

$$CR_d = \sum_{e,d}^{BZ}(P_d - P_e) \times F_{e->d} \tag{3}$$

Redispatch costs are intuitively the sum of up- and down regulation costs:

$$RC_{tot} = RC_{up} + RC_{down} \tag{4}$$

where U_n denotes up-regulated supply and D_n the down-regulated supply at each generator n. The formulas are based on ENTSO-E (2025a, Annex 3 p.27).

$$RC_{up} = \sum_{n=1}^{N}(UR_n * (MC_n - \mu_n^+)) \qquad RC_{down} = \sum_{n=1}^{N}(-DR_n * (MC_n - \mu_n^-)) \tag{5}$$

Given these four components, total welfare W in one year (8760 hours) within a specific bidding zone d is equal to:

$$W_d = \sum_{h=1}^{8760} CS_{h,d} + PS_{h,d} + CR_{h,d} - RC_{h,d} \tag{6}$$

, where h denotes each hour during the whole year. The welfare impact of a policy, for example redispatch can thus be compared by subtracting the total welfare at *dispatch* scenario from the total welfare after *redispatch*:

$$\Delta W = W_{redispatch} - W_{dispatch} \tag{7}$$

Finally, the welfare (change) can be aggregated at country level. The equation below grants the total change in welfare for Swedish market actors in all four bidding zones:

$$W_{tot} = W_{SE1} + W_{SE2} + W_{SE3} + W_{SE4} \tag{8}$$

While this measure represents the ultimate measure of the welfare change for Sweden as a whole, it would not provide a holistic measure of welfare impact. This study breaks down the welfare analysis on different bidding zones, actors, and seasons to provide a more nuanced picture of the welfare impact of redispatch.

While redispatch and cross-zonal integration generally enhance welfare by enabling more efficient allocation of electricity, they are not without drawbacks. Achieving higher transmission capacity typically allows for greater welfare gains, but persistent reliance on redispatch may distort investment incentives. As Hirth et al. (2019, p.27) notes, redispatch can systematically increase profits for generators in excess areas, potentially encouraging investments that exacerbate congestions rather than alleviate them. This unfavourable incentivisation from redispatch challenges the uniform pricing approach that redispatch alone leads to long-term efficiency. Moreover, redispatch can give rise to inc-dec gaming, where producers strategically alter their bids to benefit from redispatch payments, which tends to be higher than day-ahead prices (Delgadillo and Reneses, 2013; Holmberg, 2024). Hirth et al. (2019) and Ehrhart et al. (2022) find that incdec gaming does not require market power, and (Ehrhart et al., 2022, p.18) find that incdec gaming occurs regardless of congestion levels and market size. Such behavior inflates redispatch costs and can undermine overall welfare. These inefficiencies highlight that while remedial actions are useful for handling short-term imbalances, structural grid limitations are better addressed through long-term investments and market design improvements.

The theory section suggests redispatch enables higher quantities of electricity to be traded, generally resulting in welfare gains for the actors (producers and consumers) in the electricity market. This study aims to evaluate whether the welfare gains outweigh the costs associated with redispatch. A cost-benefit analysis may help to analyse this issue.

3.3 Cost-Benefit Analysis

A Cost-Benefit Analysis (CBA) compares the aggregated benefit to the aggregated cost for the involved actors to calculate the net welfare. The net welfare change is obtained by comparing a treatment scenario to a status quo. The objective in a CBA is to evaluate whether a certain policy or action is motivated in terms of welfare effect on the actors[18], in this case the welfare impact from redispatching. The Swedish TSO Svenska Kraftnät is a state-run TSO with legally established objectives to maximise welfare. Considering this objective, a partial CBA[19] would be apt to evaluate the welfare impact from redispatch on the Swedish grid actors.

Total welfare in any market is typically calculated by adding the aggregated producer surplus to the aggregated consumer surplus (Hultkrantz and Vimefall, 2020, p.51). In the electricity market context, a cost-benefit analysis often evaluates the monetised welfare effects which the treatment or policy (in this case redispatch) has on the actors. This is reflected by the electricity market utility (EMU), which Svenska Kraftnät (2021, p.68) presents as part of their template for an electricity market CBA. A positive electricity market utility is also the primary criteria in the Bidding Zone Review for which the treatment's net impact needs to be positive before reviewing all other 22 criteria ENTSO-E (2025a, p.22). The EMU consists of Consumer Surplus, Producer Surplus, Congestion Rent, and Redispatch Costs Svenska Kraftnät (2024c, p.43). Figure 11 illustrate an example of how the EMU components change from status quo to the treatment scenario. The congestion rent that TSOs collect from price differences between bidding zones is considered a welfare gain, as EU regulation mandates it be used for actions that relieve congestion (such as remedial measures, bidding zone reviews, or grid investments) that ultimately benefit market participants Svenska Kraftnät, 2024a. Followingly, redispatch costs are marked as costs, subject to optimisation. From the market actors perspective, congestion rent and redispatch costs can be likened to deposits and withdrawals in a kind of "congestion insurance scheme". The net welfare effect of market integration and zonal pricing is then the gross welfare gain minus the costs of redispatch, as fig. 11 illustrates.

The general changes from redispatch can again be illustrated by increasing F_x in fig. 10, where the four components change from increased redispatch. As redispatch costs rise with redispatched quantity, the congestion rent decreases due to increased price convergence. This in-

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[18] In this case, the Producers and the Consumers are the relevant actors, while the TSO, which accounts for the grid system, acts as a market facilitator

[19] A full CBA is beyond the scope of this thesis.

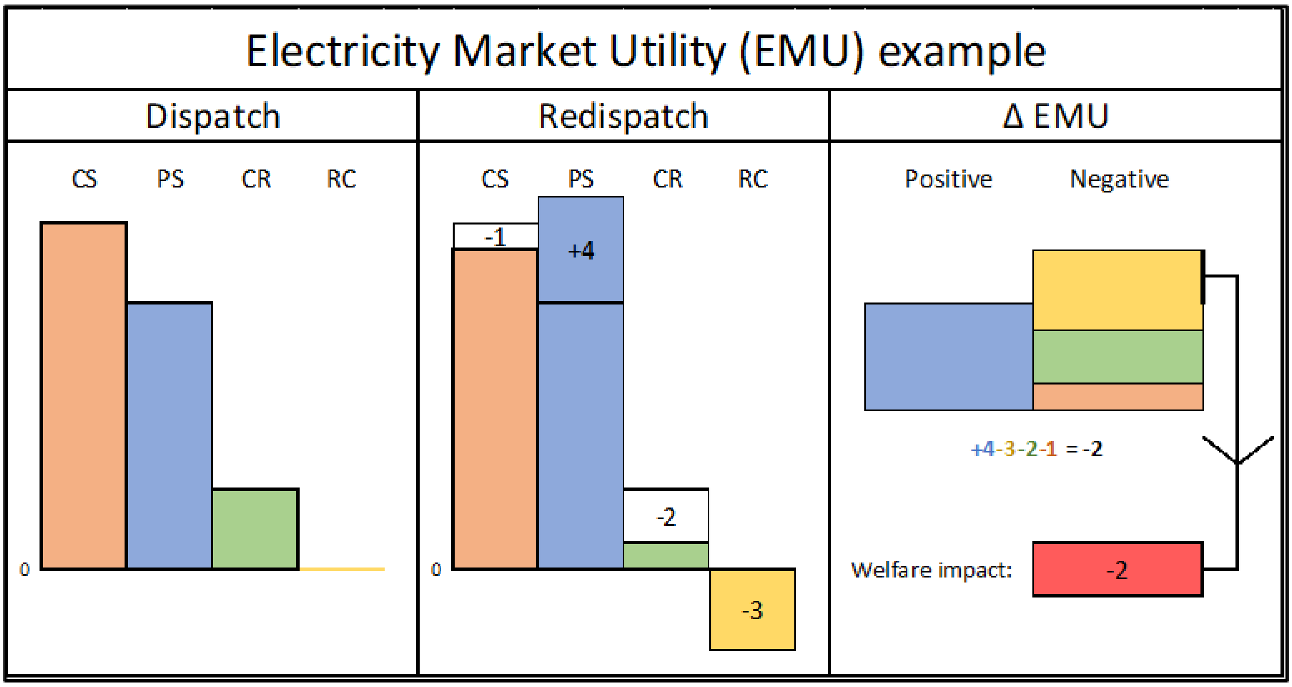


Figure 11: This is an example figure that visualises how the EMU is calculated from dispatch to redispatch. The four EMU components CS, PS, CR, RC are Consumer Surplus, Producer Surplus, Congestion Rent, and Redispatch Costs.

dicates strongly that redispatch both reduces the inflow and increases withdrawals from the ”congestion insurance scheme” that is the accumulated congestion rent. Among the alternative uses for this account is grid expansion, meaning that higher congestion rates (= more redispatch) today depraves resources from long-term investments that would have a similar welfare effect but with higher reliability and lower variable costs. On the other hand, the welfare benefits may be worth the costs, depending on the situation. The stylised graphs show ambiguous results for producers but net-zero impact on consumers. To investigate the welfare impact closer, the main results of welfare change in Sweden is complemented with a breakdown for each of the four components.

Based on earlier studies, theory, and the author’s own reasoning, the causal impact chain can be modelled as fig. 12. Fundamentally, as redispatch actions are emplyed to resolve congestions, it is expected that periods with higher probability of congestion require more redispatch, which leads to larger welfare impact. In short, the more congestion there is, the larger the redispatch impact on welfare would become. Also, since CS and PS depend on prices, higher prices amplify welfare effects, all else equal. Driving force behind congestion probability consists of an array of factors. Based on earlier studies, the most impactful factor is the minRAM, which may create overload if planned flows F_x approach the feasible capacity F_{RAM}. The probability of this happening gets higher when the overall turnover rise. Therefore, periods with higher demand (which largely correlates with the yearly temperature cycle, fig. A6) will often result in more congestion than periods with lower demand. This reasoning suggests that redispatch impact may be larger in populous bidding zones, and during the winter, all else equal. The intermittent supply is another major factor that occasionally create large fluctuations in the grid flows, causing congestion. The geographic dispersion also implicates higher flows in the grid, contributing to higher probability of congestion. It also follows from theory that redispatching

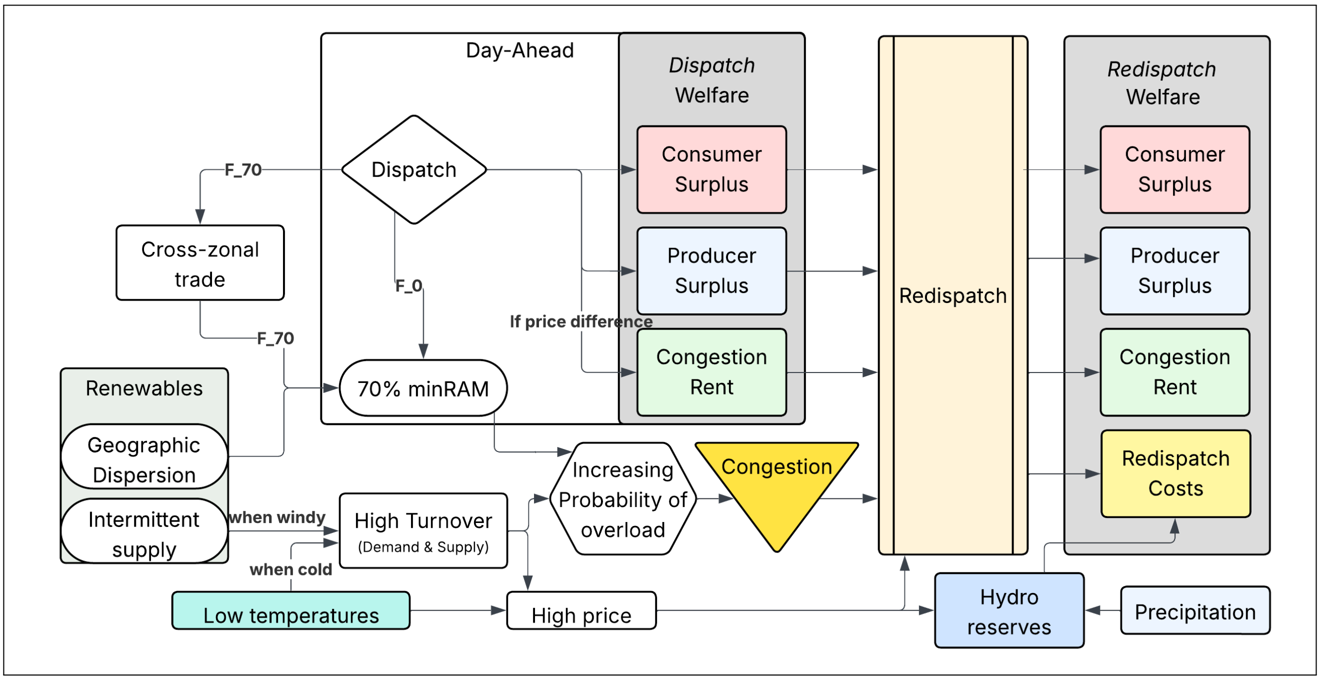


Figure 12: Flowchart of posible causal links to redispatch. Made by the author.

when there is a large price divergence between two zones will in general lead to larger changes in congestion rent. Finally, the redispatch costs tend to be low where flexible low-cost generation like hydro power is situated, and this effect is affected by precipitation.

4 Method

This study presents a quantitative welfare analysis based on simulation data from part of the Bidding Zone Review report by ENTSO-E (2025a). The analysis is based on a comparison of welfare between the status quo scenario, called *dispatch* and the treatment scenario, called *redispatch*. The difference between these cases reveal the welfare change (or welfare impact) from implementing the 70%-rule at day-ahead. This allows an indication of the welfare impact from redispatch that is implemented to alleviate the congestions associated to 70%-rule.

Dispatch is based on the outcome at the day-ahead market (left gray box in fig. 12) for which the market coupling algorithm finds the optimal market outcome based on ex-ante capacities, *without applying the minRAM 70%-rule.* Although overloads do occur from the *dispatch* scenario, the data contains no redispatch actions.

Redispatch is a two-step simulation process. First, the outcome of the day-ahead market is determined while *incoporating the minimum RAM 70%-rule.* In the second simulation step, any overloads identified in the first step are resolved by optimizing remedial actions within the Nordic power system.

This study uses simulations with the 70%-rule (*Redispatch*) and without the 70% rule (*Dispatch*) as a proxy to examine the effects of redispatch. Alternatively, the difference between *Dispatch* and *Redispatch* can be interpreted as the welfare impact of moving from current capacity allocation standards to a proactive redispatch approach, where the 70% minimum RAM requirement is applied already in the day-ahead market, as opposed to current redispatch practice drawing resources from the balancing market.

The modelling of redispatch actions in the simulation represents a potential limitation. In reality, redispatch actions are typically activated through the balancing or intraday market, as discussed in the background. However, in the Bidding Zone Review, ENTSO-E simplifies redispatch optimisation to reduce model complexity: "In the [redispatch optimisation], the DA market dispatch was resolved with an additional layer of constraints, namely the transmission constraints, together with a cost applied to up- and downregulate the production" ENTSO-E (2025a, p.120). This means redispatch is modelled as a re-optimisation of the day-ahead dispatch considering the grid constraints, using the bids submitted to the day-ahead market. This excludes the flexibility that might be available in balancing and intraday markets where redispatch occurs in practice, which is a limitation. It also disregards that there are relatively more actors in balancing and intraday which might cause redispatch costs in this simulation to be lower than in reality, especially in times where prices are high because feasible actors may be less effective and more expensive faster with fewer available actors. The re-solve includes mark-up costs for each generator (listed in table A1 in the appendix) to reflect redispatch costs of up- and down-regulating generators. The resulting outcome is reflected by the *redispatch* scenario. Although this approach lacks the real dynamics of redispatch, it approximates the cost implications reasonably well. Therefore, this scenario is referred to as redispatch actions throughout this study. The redispatch simulation was designed in such a way that makes it possible to simulate without being too data-intensive; an approximation of the rather intricate process of redispatching.

The difference between *dispatch* and *redispatch* is limited to the incorporation of the activated redispatch and its welfare effects. The congestions that arise between *dispatch* and *redispatch* is due to the application of the 70% minRAM regulation in redispatch where, for some network elements, more capacity is given to cross-border flow than is actually available when accounting for the internal flows.

4.1 BID-3

The main model in this study is AFRY's BID-3 market simulation model (Afry, 2025). BID-3 is used to analyse both short-run market outcomes and long-run investments in the power system. In this study, the EMU data is gathered from a BID-3 simulation which constituted part of the 2025 ENTSO-E (2025a) bidding zone review. The simulation covers the entire European grid, taking into account both generation and transmission constraints within and between the bidding zones (ENTSO-E, 2025a, Annex 3, p.18).

BID3 is a partial equilibrium simulation model that, based on assumptions regarding fuel and emissions costs, technology development, policy instruments, and demand trends, identifies an optimal cost-minimizing solution for system operation. The simulation for this study is based the grid of 2025. Electricity demand for households and industries is largely specified exogenously, while electricity consumption in energy-intensive sectors such as district heating and transport is determined as part of the optimization process. BID-3 also wields the capability to model balancing reserves, such as mFRR and aFRR, where both capacity procurement and activation are regarded, to analyse system balancing and remedial actions. Moreover, the model can implement the 70% rule in accordance with the EU Electricity Regulation (2019/943), requiring that at least 70 percent of cross-zonal transmission capacity be made available to the market. ENTSO-E (2025a, p.131) expresses that topological remedial actions were excluded from the model due to their complexity and data requirements (see Appendix A7 for a brief explanation of topological actions).

The relative strength of the BID-3 model is that it captures relatively many factors in the complex and multifaceted Nordic electricity grid and market. Apart from the four factors lined out, the model also captures transmission losses. Regarding the environmental externalities, these costs are included to some extent as supply bids incorporate the EU Emissions Trading System mechanism Energimarknadsinspektionen (2018, p.13). Table 2 shows the effects that are directly and indirectly incorporated in the BID-3 model, and therefore incorporated into the EMU welfare measure. Another strength with ENTSO-E's simulation is the detailedness, with nodal resolution and carefully designed simulation mechanics. To the author's knowledge there are no other studies analysing welfare impact by redispatch with a model applied on the real grid on such a large scale and high detail input data in the Nordics.

Table 2: List of the welfare effects inorporated in the BID-3 simulation model.

Effect	**Evaluation, Source**
Consumer Surplus	EMU
Producer Surplus	EMU
Congestion rents	EMU
Redispatch Costs	EMU
Transmission losses	Incorporated in BID-3
Environmental negative impact via greenhouse gas emissions	Partly incorporated in market prices via ETS in the EU

Software Programmes and Artificial Intelligence

The programming language R is used for the quantitative analysis and most figures presented in this study. Packages used include *dplyr, ggplot2, gridExtra, tidyr, zoo.*

The AI tool ChatGPT by OpenAI has been used for several supportive services in this study. The services include generating programming code, finding sources, and suggesting improvements to the content.

I take full responsibility for the entire content in this study.

5 Data

The results in this study is based on output data from BID-3 simulations part of the bidding zone review by ENTSO-E (2025a). Due to the input data being extensive and complex, it is not reproduced here. Instead, this section provides the most relevant features. The simulation output data that is used for this study consists of the four EMU welfare components over the full year 2025, consisting of 8,760 hours. The data is limited to Swedish actors, meaning that any welfare effects in other countries are not reflected in the results.

5.1 Input data and Model

The BID-3 simulation model builds on a number of assumptions detailed in both ENTSO-E (2025a, Annex 3) and (ENTSO-E, 2025c, 16:00-21:00). Downloadable input data is publicly available at ENTSO-E (2025a). As noted by (ENTSO-E, 2025a, p.129), the input market data come from the Midterm Adequacy Forecast report, the Ten-Year Network Development Plan (ENTSO-E, 2025b), and the EU *Locational Marginal Pricing* study ENTSO-E (2022). The simulation assumes an intact grid model for 2025, meaning that it assumes the forecasted 2025 European grid system with no network elements out for maintenance throughout the whole year simulation (ENTSO-E, 2025c, 17:15). The N-1 restriction and transmission reliability margins were incorporated, ensuring that the grid can always handle failure of any single component at any time. The inclusion of these factors reflects current praxis for capacity allocation. Changing factors such as temperature variations, grid maintenance, and grid topology actions are not incorporated in the simulation (ENTSO-E, 2025c, 33:30). The capacity calculation and day-ahead dispatch was simulated by Flow-Based Market Coupling for the Nordic CCR, and the other European markets were approximated with NTC approach. In this way, the simulation considers the whole European system, making the data in this study more reliable. These simplifications were chosen in order to keep data manageable for the BID-3 model.

The weather year 1995
An important note is that this study draws climate indata from only one *weather year*, based on 1995 temperature, precipitation, and solar radiation data. The weather year is overall relatively neutral in terms of average precipitation and temperature. In the Nordics, CBAs often include up to 35 weather years to account for the decisive impact that hydro power has on the market dynamics. Due to time constraints, it was only possible to include one weather year. The lack of additional weather years is a limitation which could bias the results,. For example, it could imply certain results are skewed by a non-representative temperature shock or unusual precipitation patterns, affecting the Nordic hydro power redispatch. On the other hand, this specific weather year could provide valuable insights on how welfare effects of redispatch changes by special circumstances.

The report by SMHI (1995, p.244) about the weather year 1995 reveals a couple noteworthy events, applied on the current grid of 2025. A cold spring, combined with above-normal rainfall once temperatures climbed, caused large inflows to hydro reservoirs in May, dubbed by the institute as one of the largest spring floods of the century. Depressions in March and April brought periods of high wind speeds. The summer was relatively normal, as wind speeds picked up again in the autumn. However, the autumn was dry, leaving hydro reserves relatively low for the winter. For the rest of the year, hydro inflow was less than normal, leading to constrained hydro reservoirs by the end of the year. In November 17th, one of the worst snowstorms in Swedish history hit large parts of its Southern half, beating snow depth records in Göteborg, Jönköping and Linköping SMHI (1995, p.204). Outages occurred due to damaged infrastructure. While the simulation does not account for the risk for outages, the temperature drop and storm winds in November have potential to cause congestions. From November onwards, temperatures were colder than normal. Some locations had the coldest December of the 1900's, with below -20°C in Southern Sweden at Christmas Day. This cold spell lingered until New Year's Day. Large parts of interconnected countries were also colder than normal. This extraordinary cold spell should have an impact on the results, especially given that the hydro reserves run low after the dry autumn and high demand from cold onset of the winter. Despite a dry second half, in terms of total hydro inflow 1995 was comparatively average with 235 TWh hydropower. For reference, the median yearly hydro output in the Nordics is around 225 TWh.

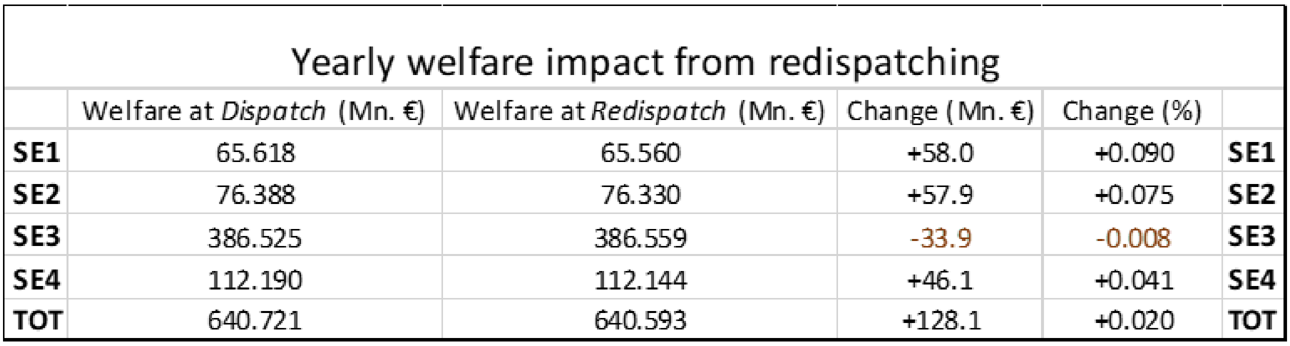
6 Results, Analysis & Discussion

This section provides results, accompanied with analysis and discussion on each piece of results. The results are generally presented in increasing detail, starting with the aggregate overall results and ending with specific insights. All results provided are calculated by the author, from the raw data of ENTSO-E (2025a). The results are also discussed qualitatively, based on the weather year and theory.

Redispatch is a necessary tool for the TSO to ensure grid stability and provides an interim solution before grid investments are realised. However, earlier studies have been inconclusive on the net welfare impact of redispatch. While the minRAM is backed up as an efficient factor to increase market integration, its rigid application causes the majority of congestions in the simulation of this study. A study that resembles the methodology of this study by Bucksteeg et al. (2024) finds a negative welfare impact from redispatching in Central Europe. Other studies find that the minRAM and entailing redispatch unlocks higher degree of market integration benefits. Meanwhile, official bodies report that increasing demand coupled with lagging grid expansion, and the Energy Transition with increased intermittency, are likely to contribute to more congestion, raising redispatch costs in the coming decade.

In this study, total net welfare benefit from redispatching to resolve congestions was approximately +€128 million, as table 3 shows. This amount reflects the aggregate welfare gains for all of Sweden, based on this study's simulation on the grid system of 2025. These welfare gains translate into €35.370 per day on average, which is a mere 0.02% increase from the average welfare at dispatch; the breakeven point. The Northern bidding zones had the highest net positive impact from redispatch while SE3 had a slim negative change in welfare.The likely cause for negative change is that congestion rents decrease by redispatch, which affects SE3 due to the high flows between SE2 and SE3.

Table 3: Yearly aggregate welfare change from redispatching.



Yearly welfare impact from redispatching

	Welfare at *Dispatch* (Mn. €)	Welfare at *Redispatch* (Mn. €)	Change (Mn. €)	Change (%)	
SE1	65.618	65.560	+58.0	+0.090	**SE1**
SE2	76.388	76.330	+57.9	+0.075	**SE2**
SE3	386.525	386.559	-33.9	-0.008	**SE3**
SE4	112.190	112.144	+46.1	+0.041	**SE4**
TOT	640.721	640.593	+128.1	+0.020	**TOT**

Although large in absolute monetary value, the welfare gain of 0.02% from redispatching is arguably within the margin of error, requiring further investigation. This inconclusive aggregate result aligns with the ongoing debate on the welfare effect of redispatch. While the raw and aggregate result show that the net welfare impact of redispatch is positive, the net impact is negative in SE3, the most populous bidding zone, and the Northern bidding zones gain most welfare from redispatch. Questions remain to as why the net impact is so small and how the welfare is distributed across its components, throughout Swedish bidding zones, and across time. The continuation of this section deals with fleshing out reasons that may explain the welfare impact in higher detail, and nuances the results from different perspectives.

6.1 Distributional analysis

The distributional analysis breaks down welfare change by its component: Consumer Surplus, Producer Surplus, Congestion Rent, and Redispatch Costs. The results are interpreted mainly from a theoretical standpoint.

When removing the welfare change for consumers, the total welfare impact turns negative at -€335 million. This implies that welfare impact from redispatch hinges on enhancing consumers surplus. As fig. 13 shows, the consumer surplus makes up for lost producer surplus, lost congestion rent, and the redispatch costs. Net impact on Consumer surplus amounts to +€460 million whereas Producer surplus drops with -€150 million.

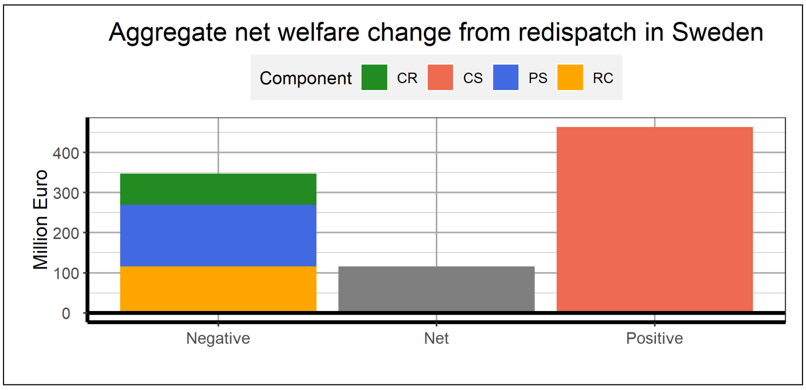
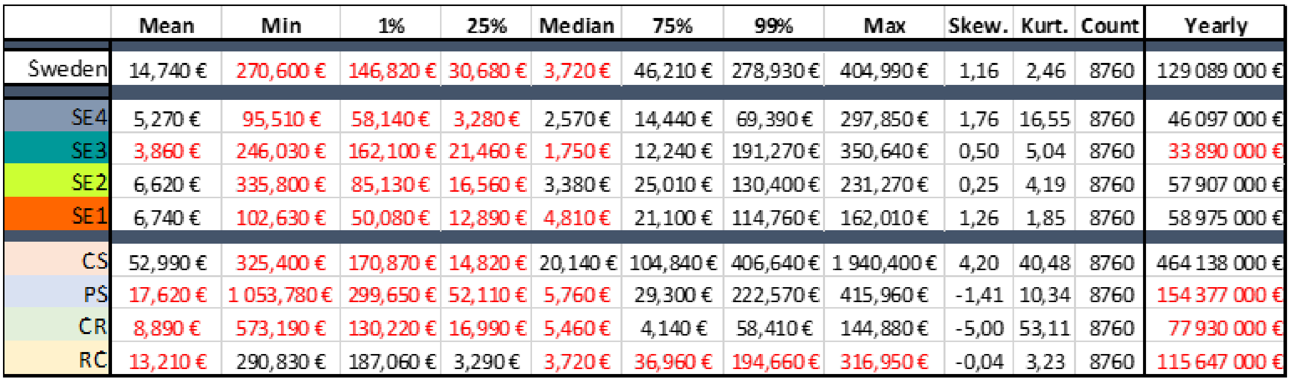


Figure 13: Welfare change by component. The large positive welfare change in Consumer Surplus makes up for the net negative welfare change from the other components.



	Mean	Min	1%	25%	Median	75%	99%	Max	Skew.	Kurt.	Count	Yearly
Sweden	14,740 €	270,600 €	146,820 €	30,680 €	3,720 €	46,210 €	278,930 €	404,990 €	1,16	2,46	8760	129 089 000 €
SE4	5,270 €	95,510 €	58,140 €	3,280 €	2,570 €	14,440 €	69,390 €	297,850 €	1,76	16,55	8760	46 097 000 €
SE3	3,860 €	246,030 €	162,100 €	21,460 €	1,750 €	12,240 €	191,270 €	350,640 €	0,50	5,04	8760	33 890 000 €
SE2	6,620 €	335,800 €	85,130 €	16,560 €	3,380 €	25,010 €	130,400 €	231,270 €	0,25	4,19	8760	57 907 000 €
SE1	6,740 €	102,630 €	50,080 €	12,890 €	4,810 €	21,100 €	114,760 €	162,010 €	1,26	1,85	8760	58 975 000 €
CS	52,990 €	325,400 €	170,870 €	14,820 €	20,140 €	104,840 €	406,640 €	1 940,400 €	4,20	40,48	8760	464 138 000 €
PS	17,620 €	1 053,780 €	299,650 €	52,110 €	5,760 €	29,300 €	222,570 €	415,960 €	-1,41	10,34	8760	154 377 000 €
CR	8,890 €	573,190 €	130,220 €	16,990 €	5,460 €	4,140 €	58,410 €	144,880 €	-5,00	53,11	8760	77 930 000 €
RC	13,210 €	290,830 €	187,060 €	3,290 €	3,720 €	36,960 €	194,660 €	316,950 €	-0,04	3,23	8760	115 647 000 €

Figure 14: Descriptive statistics of the change in welfare on each bidding zone and each component.

The descriptive statistics of welfare change between *dispatch* and *redispatch* is provided in fig. 14, and the violin plots in fig. 15 visualises the distribution of the welfare impact on each bidding zone. All four zones assume a distribution with heavy concentration around zero and with extreme values at both directions. Average welfare change is positive in SE1, SE2, and SE4 but negative in SE3. In SE3, the 25% quantile has a more negative value than the 75% quantile is positive, which is not the case in the other zones. This, and the distribution in fig. 15 indicate a slight tendency for redispatch to have negative impact on SE3. Another point of interest is that the median welfare impact on SE1 is negative but the mean impact is positive, indicating high welfare change when it is needed. Figures A6-A9 show the violin plots by each component. In fig. A10, SE3 has significantly higher redispatch costs, possibly due to often having higher prices than SE2, meaning congestions between SE2-SE3 are often solved by upregulating supply in SE3. It could also depend on the east-west flows that arise within SE3 in certain conditions. Another note is that the distributions for CS and PS (fig. A12-A13) have relatively inverse appearances, but changes in CS are relatively smaller in magnitude. This aligns with theory and equation 1, as generators are involved in redispatch.

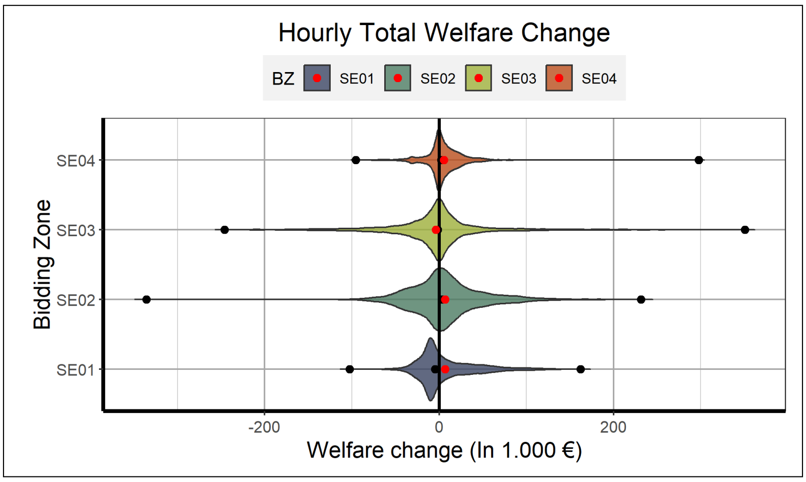


Figure 15: Violin plots of the welfare change from *Dispatch* to *Redispatch*. Minimum and maximum values are indicated by black points. The mean value is indicated as a red dot. Median values are indicated in black but it is only distinguishable from mean value in SE1.

6.2 Temporal Analysis

The temporal analysis breaks down the welfare impact hour by hour, and combines theory with the input weather year data of 1995 to interpret the plotted results. The yearbook of SMHI (1995) was instrumental for this purpose.

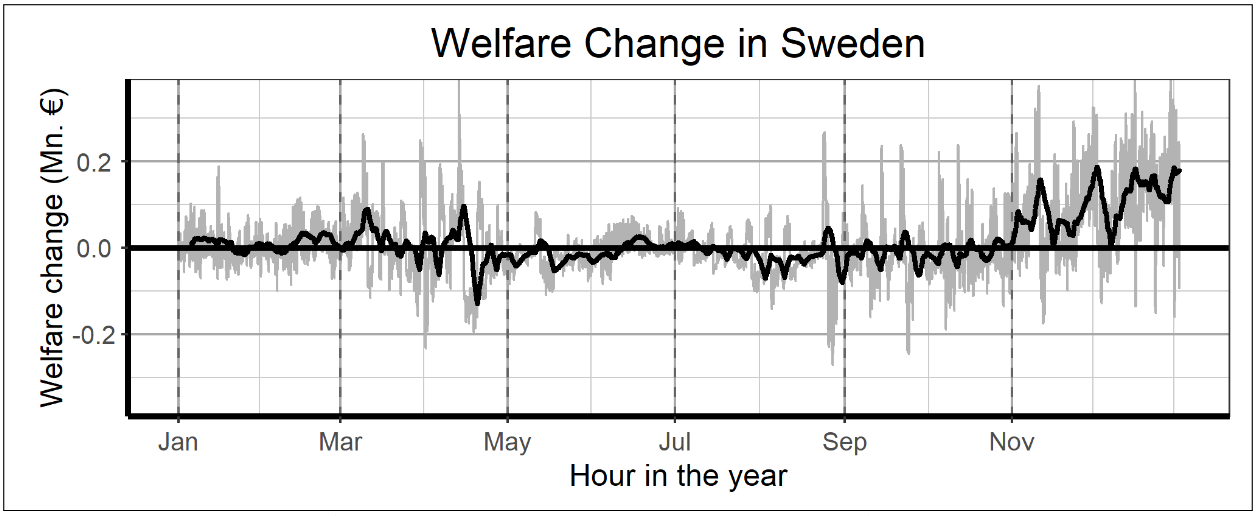


Figure 16: Welfare change from redispatching throughout the year. Gray line marks each hour, black line marks a 168-hour moving average (1 week).

When plotting the hourly welfare change by hour in Sweden (fig. 16) there are several points to notice. First, the welfare change seems to be low in the summer months, possibly because summer demand is about two-thirds of winter demand on average (see Appendix 6) resulting in lower probability for congestion. Another possible cause is the large spring flood in Norway and Sweden in May, resulting in abundant hydro power throughout the summer, possibly reducing prices. Low prices also tend to dampen the effect of redispatch. Second, the change in welfare oscillates heavily between positive and negative in the spring and autumn, that are generally more windy than summer and winter, which is also the case for 1995. As earlier studies indicated, the large volumes of redispatch needed to accommodate intermittent power lead to these oscillations. Third, there is a rise in net *redispatch* welfare impact from November onwards. The cold onset of winter in 1995 might have caused higher volumes and therefore more congestion. In the very end of 1995, a cold spell with record low temperatures in Southern Sweden likely causes extraordinary volumes. The net welfare impact stayed positive even in the coldest temperature. This suggests that welfare impact from redispatch may be higher than normal during high demand which comes with extreme cold, in line with expectations.

More insights are retrieved when breaking down welfare impact by bidding zone and component. Figures A4-A7 in the appendix presents welfare change by component and bidding zone in full detail. Followingly, fig. A11 shows the aggregate welfare change by bidding zone. Looking at each component, SE3 shows the largest overall movements in CS and PS, probably due to being the largest bidding zone by volume, population, and redispatch costs. Conversely, there are minor welfare changes in SE1, who has the lowest yearly turnover. However, in Figure A8 all four zones display about equivalent magnitudes in overall welfare change hour by hour. Welfare impact in SE1 and SE2 increases throughout the end of the year, mostly due to a rising producer surplus, possibly from up-regulated hydro power which is dominant in the North. Occasional spikes in SE3 seem to have a large impact on overall welfare, mostly driven by bursts of redispatch. Possibly this is related to activation of thermal and gas plants, who have high costs. Welfare impact in SE2 is slightly negative, mostly due to a decreasing congestion rent from redispatching. Redispatching likely abates the traditional congestion between SE2-SE3. At the cold spell in December, CR drops sharply, and CS rise in the Southern bidding zones; less power was transmitted and more redispatched. Based on the high demand, redispatch likely resolve severe congestions that would have caused large welfare losses if left unresolved. The redispatch costs in SE3 is a peculiar graph, showing violent fluctuations, often going below zero. This is because certain redispatch costs are avoided when comparing to the dispatch scenario. These fluctuations seem to only affect SE3, indicating it could have been caused by east-west flows that are prevalent during windy conditions in the south. The welfare effect in these periods are highly variable.

To capture the overall distributional dynamics among bidding zones, fig. 17 below plots the welfare impact for each bidding zone. This graph illustrates the distribution of welfare impact from redispatch across Sweden based on the model assumptions. Welfare change fluctuates in irregular patterns around net-zero in all four bidding zones for most of the year. Looking at Figure A7, it is possible that the large congestions from east-west-flows cause these spikes, lasting several hours at a time. Another noteworthy insight is that the welfare impact is largest in SE1 at the year's end, proving that net welfare impact in the smallest bidding zones can be large in absolute numbers. Negative welfare impact mostly derives from the erratic movements in SE3, but also from changes in SE2's Congestion Rent. Overall, the most significant insight from fig. 17 is the trend break in November. During the two last months, the welfare impact from redispatching increases in the Northern bidding zones, driving up overall welfare gains. A possible reason is that there are large welfare gains from redispatching with hydropower when demand and price levels rise daytime in the winter, which was expected. The end of December shows a swift welfare redistribution from SE2 to the Southern bidding zones, possibly due to welfare gains from relatively cheap redispatch by renewables like hydropower.

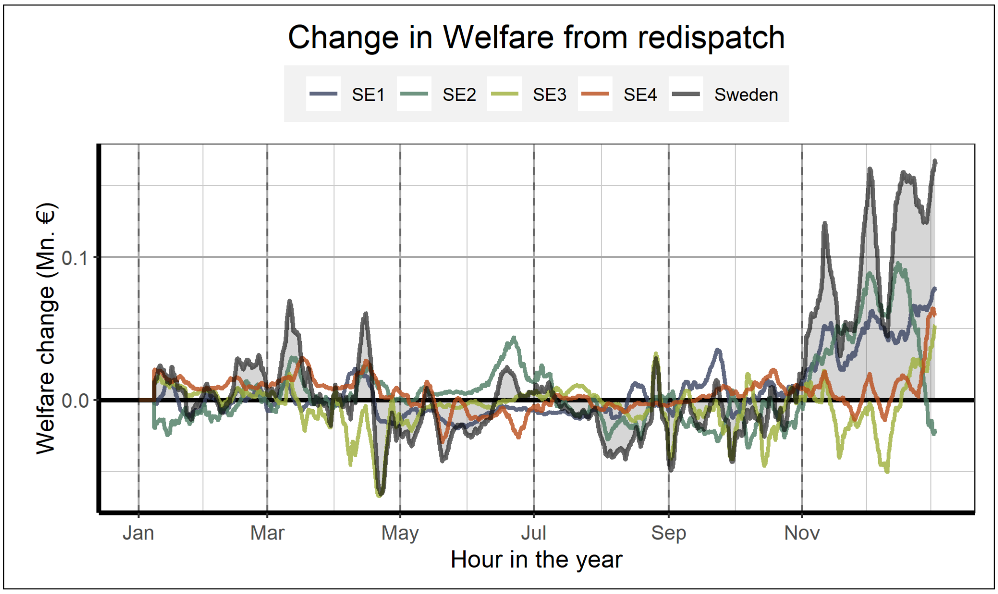


Figure 17: Welfare change in Mn. € by each bidding zone, with total Swedish welfare change in gray.

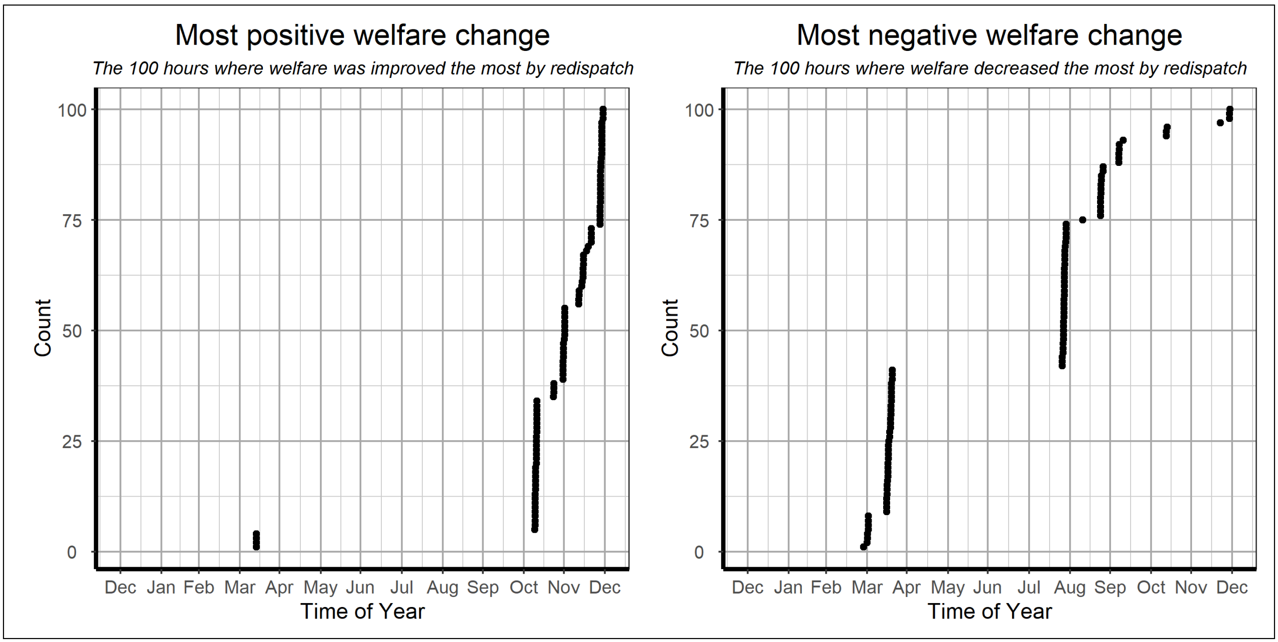


Figure 18: To the left: The 100 hours where net welfare increased the most by redispatch. To the right: The 100 hours where net welfare decreased the most by redispatch. Most positive welfare effects happened in the winter, while negative change was most common in autumn and spring.

The two plots in fig. 18 plot the 100 hours with the highest and lowest net welfare impact in Sweden, respectively. The high ratio of positive extremes after November supports the notion that redispatch renders welfare gains during cold temperatures[20]; the cold snap caused 25% of the extreme positives. Regarding the negative extremes, there is a larger dispersion in general. Half of negative extremes occurred at the end of August or middle of April. The negatives in april may be related to the extraordinarily heavy spring flood, and the August extremes coincide with a sharp drop in temperatures at the 24th of August (SMHI, 1995, p.145). The two plots in fig. 19 below show the 100 extreme values for each bidding zone. The most positive changes in welfare coincide with colder temperatures, especially for SE1 and SE2. Meanwhile, extreme values in SE3 were mostly in the spring and autumn. The negative extremes are dispersed throughout the year for SE1, SE2, and SE3. but in SE4 the majority is concentrated to May and June. The negatives in May coincide with the unusually late snowstorm May 14th, and the negatives in June coincide with high wind speeds in Southern Sweden. The high wind speeds in Southern Sweden correlates with negative extremes, possibly related to Danish and German wind power.

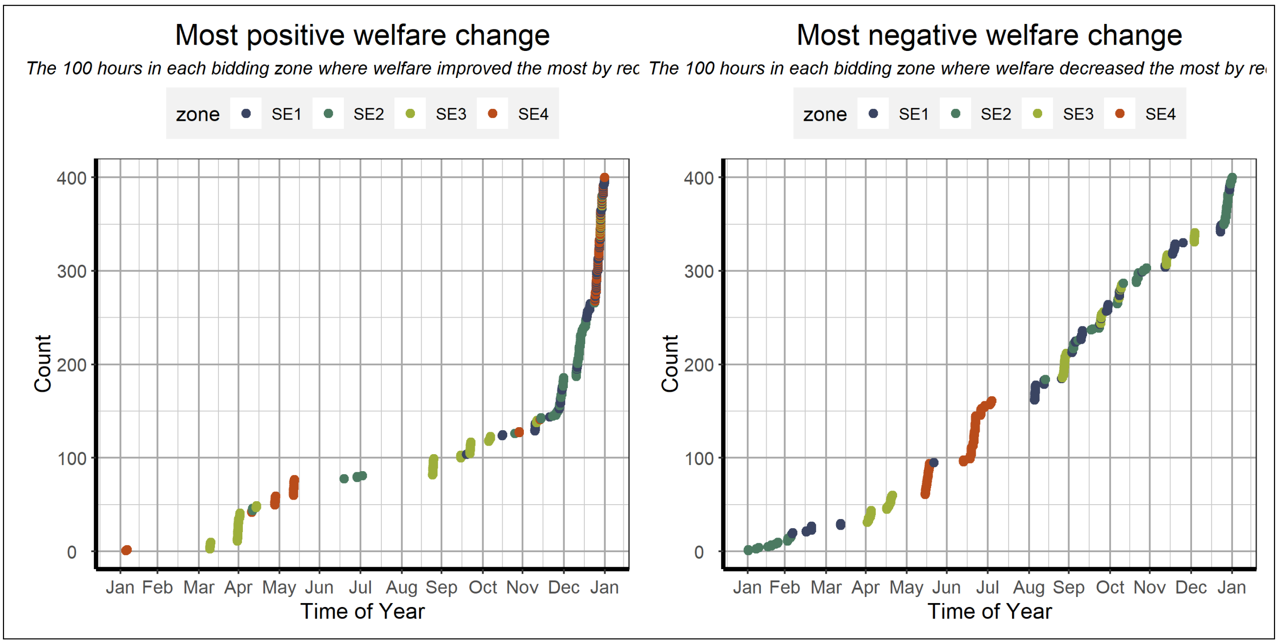


Figure 19: To the left: The 100 hours where net welfare increased the most by redispatch. To the right: The 100 hours where net welfare decreased the most by redispatch. Most positive welfare effects happened in the winter, while negative change was most common in autumn and spring.

6.3 Short term implications of redispatch

In the short term, redispatch provides an appropriate welfare effect while also being necessary. Compared to other tools, literature indicates redispatch is the conventional and most reliable tool for congestion management in the short term. Without redispatch there would probably be major problems, so in a literal sense the welfare effect is immesurable from a grid stability standpoint. The results indicate redispatch may provide most positive welfare impact under stressed conditions. Redispatch show a clear positive impact during extreme cold temperatures, where it provides extra demand when the price is high, and thus also marginal benefit is high. Redispatch costs are comparatively low and are generally compensated by increased consumer

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[20] See fig. 12

surplus, showing that redispatch benefits consumers. Redispatch therefore seems not only necessary, but overall slightly beneficial in the short-run.

6.4 Long term implications of redispatch

The Swedish government has delegated Svenska Kraftnät to investigate the prospects of decreasing bidding zones, to either three, two, or a uniform pricing which reduces the pricing granularity(Regeringskansliet, 2025). All else equal, theory suggests reducing granularity potentially leads to higher redispatch costs; uniform pricing would by definition imply more redispatch than zonal pricing, all else equal. In light of this, it is relevant to discuss some long-term effects of redispatch compared to granular, zonal, pricing and grid expansion. One of them concerns the incentivisation effects. Redispatch distorts localisation incentives for generators, as generators in excess areas that contribute to overload are compensated when down-regulated. Had these generators been in the deficit area instead, less capacity would have been needed to accommodate the same outcome. Like earlier studies indicated, this effect is a long-term welfare inefficiency of redispatch. In Sweden, zonal pricing provides a long-term localisation incentive which reduces the geographical supply-demand asymmetry in theory, intended to reduce price differences as well. Still, price spread is increasing between Swedish bidding zones. While merging zones may seem like a good way to reduce price gaps, it would increase system costs substantially to even out the Swedish supply-demand asymmetry, and also remove much of the congestion rent which finances redispatch.

Another long term effect from redispatch is its inherent cost uncertainty. As discussed in the background, topological vicinity to the congestion was an important factor for redispatch efficiency. In extreme cases when large volumes need to be redispatched, the cost-efficiency may drop as near and cheap resources are depleted. This has serious implications for system security. Although this study does not have material to assess the magnitude of this problem, it is worth to keep in mind, especially with the increasing congestion rates across Sweden and Europe. When comparing redispatch to grid expansion in the long run, the variable costs of redispatching may need to be estimated with a risk premium to reflect this uncertainty. A third long-term implication that makes redispatch less viable is the risk for ind-dec gaming, where generators deviate from the pareto-efficient bidding strategy for potential profits, as described in detail by Holmberg (2024). Excessive reliance on redispatch has potential to increase inc-dec gaming, which is welfare inefficient.

In terms of mitigating climate change and promoting the transition away from fossil fuels, redispatch is theoretically inferior to grid expansion. As previous literature argued, increased market integration by enhanced cross-zonal capacities would smoothen out the intermittency and contribute to mitigate the congestions that are caused by renewables. Reliance on redispatch would imply less money for grid expansion that facilitates intermittent power and more money towards fossil fuels: fossil fuels are in general upregulated and renewables are curtailed leading to higher CO2eq emissions per MWh. From Sweden's perspective, with the high amount of low-cost renewables, it would be sound to prioritise grid expansion to realise market integration as far as is motivated by CBAs, which is the prevalent consensus at Svenska Kraftnät. Reliance on redispatch within and between bidding zones would deprive resources from the long term benefits of market integration. In summation, redispatch should be a second-hand alternative considering its negative externalities, such as incentivisation effect, variable costs, and alternative options.

A final point of discussion is the short-term alternatives to redispatch. Alternative methods such as demand-side flexibility and dynamic line rating (DLR) could complement redispatch. Developing demand bids' price responsiveness is crucial to avoid high prices that could lead to rising inflation and broader economic damages. DLR, in particular, could increase available capacities similarly to grid expansion, thereby lowering the probability of congestion and reducing redispatch costs. Moreover, it would be valuable to investigate whether a more proactive use of redispatch delivers greater welfare benefits compared to the current reactive approach. Future studies could apply a counterfactual analysis by comparing historical grid data with a treatment scenario that applies proactive redispatch similar to the methodology of this study: resolving the day-ahead outcome with regards to the 70% rule and then implementing a mechanism which activates redispatch at an earlier stage. By doing this, one can compare the conventional reactive stance for redispatch to a more proactive stance. Additionally, the flowchart in fig. 12 may provide inspiration for future studies on factors behind redispatch welfare.

6.5 Critical discussion

The main critical point is about the approximation of redispatching actions. It was done via a re-solve of the day-ahead outcome with the minRAM 70%-rule incorporated. This is not identical to the actual process, where TSOs activate bids in balancing or intraday market. As discussed earlier, these markets contain less actors which means that the actual redispatch costs may be understated in this study. The approximation of real redispatch cost by adding a markup could reflect the real dynamics quite well, but it is likely a simplification of reality. FOr example, the welfare effects that stem from changed price and changed quantity cannot be attributed to redispatch but rather to the 70%-rule at day-ahead. The results may therefore be more indicative for proactive redispatching at day-ahead instead of indicating the effects of current redispatch praxis. However, ENTSO-E's implementation of hydro banking makes the model reliable, and in terms of isolating the effect of redispatch, this effect may still be approximated by the 70%-rule. The denoting of the treatment scenario as redispatch could be criticised but it was kept for pedagogical reasons, as the isolated effect from status quo to treatment (70%) is a proxy for redispatch.

The omission of topological actions in the simulation model also limits the realism of ENTSO-E's bidding zone review analysis, as some congestions that would otherwise be resolved through low-cost topological measures are instead handled by redispatch, potentially inflating redispatch costs where the market is adapted to handle congestion by alternative methods. However, the substitution of topological actions with redispatch still allows for an evaluation of redispatch volumes and costs under more stressed conditions. Moreover, according to ENTSO-E (2025a), renewables indata from the *Midterm Adequacy Forecast* report from 2020 underestimated renewables expansion in the Nordics, compared to the real outcome, which may imply congestions from intermittent generation is underestimated. Another limitation is the exclusion of other countries. To get a comprehensive view of the effect one should include the whole system, but it was not possible due to time constraints. Another ciritcal point is that given the demand and supply dynamics, the demand curve is a dominant component of the welfare measure. This is arguably the case since changes in consumer surplus are overriding changes in producer surplus. While this is common in electricity market analyses, it is worth to mention this because the positive effect of redispatch hinges on the rise in consumer surplus. The elasticity of demand may differ across countries depending on the market design, and redispatch market design does vary across countries. Therefore, results should be interpreted with due consideration. Finally, the inclusion of only one weather year could degrade the generalisability of the results. While this makes the results less generalisable, it may also reflect the reality of the electricity market, where specific events often cause large impacts on the welfare. The cold spell examplifies this.

A critical point to acknowledge is that Sweden lacks a history of regular redispatch in large volumes such as Germany, which means that even if redispatch would be positive in some cases, the resources and volume may be lacking for implementing it and keeping redispatch costs low throughout. There may be a certain degree of path-dependence making redispatch less apt compared to bidding zone reconfiguration. Increasing reliance on redispatch without having the resources in place would risk security and undermine long-term grid investment potentials, as congestion rent drops and the possibility of insufficient supply rise with increasing reliance on redispatch.

Overall, the limitations of the methodology could be understating the true costs of redispatch, and overstating its positive welfare effect. Hence, the results may have a positive bias for the welfare effects. Modelling with day-ahead bids for redispatch means more resources are available than in reality, presumably lower costs. It may also neglect the effect of depleting cost-efficient up-regulation which means it understates redispatch costs at times of high demand. This could severely question the positive net results of November-December. Also, the overall positive welfare results hinges on consumer surplus, which might be overstated in reality.

7 Conclusion

This study evaluates the quantitative welfare impact of redispatch by comparing the aggregate welfare before and after redispatching. The data was obtained from a simulation by (ENTSO-E, 2025a), where input data largely resembles the Nordic grid of 2025 based on an official methodology by ACER. A large limitation of this analysis is that redispatch was modelled as a resolve of day-ahead outcome, with markups on each bid, approximately reflecting the redispatch pricing dynamics.

Results of this study show a slight overall welfare benefit of redispatch, albeit within the margin of error. Apart from being a necessary tool for maintaining grid security, the welfare impact was estimated to +€128 million on the four Swedish bidding zones (SE1, SE2, SE3, SE4) combined. Based on the calculations of this study, net welfare gains in consumer surplus outweigh the welfare losses in the other components, indicating that redispatch has a large net positive impact on consumers overall, but may not benefit generators on average. Furthermore, the breakdown on welfare components indicates that the welfare impact on producer surplus and consumer surplus have an inverse relationship, especially in SE3, where consumer surplus and producer surplus show inverse pattern and the net welfare change ends up close to zero.

The lack of multiple weather years is a potential limitation, making the results sensitive to the weather events of the chosen weather year. While this makes the results less generalisable, it may also reflect the reality of the electricity market, where specific events often cause large impacts on the market outcome. The relatively dry and cold ending of the 1995 weather data provides a case study of redispatch impact during a cold spell during the end of December. While the net impact from redispatch fluctuates around zero for much of the year, it grows higher during the cold months, and stay high during the cold spell for Swedish bidding zones. Most extreme positive welfare changes were in this period. The results indicate that redispatch may provide high welfare gains when demand approaches the steep section of supply, where prices are likely higher and the benefits are amplified. It should also be noted that these results are applicable to Sweden, but may be less applicable to other countries depending on the relative supply and market dynamics, as well as on the elasticity of demand and supply.

Although redispatch may provide a slightly positive welfare impact in the short run, the effect is marginal when considering this study's limitations, as they may have introduced a positive bias that affects the result and makes the overall welfare effect uncertain. Therefore, redispatch may have a neutral, or even negative, welfare effect on the short run, other than being a necessary tool for grid security. In the long-run, systematic reliance on redispatch risks leading to higher system costs and adverse effects such as inaccurate incentives and slower integration of renewables. Above all, redispatch costs reduce the budget for grid investments that can accomplish a more positive and stable welfare effect in the long run. This is also relevant for the ongoing bidding zone review, where larger bidding zones lead to lesser congestion rent and higher redispatch costs, shifting money from long-term grid investments to short term redispatch measures. Grid investments should therefore be prioritised in the long term to realise the benefits of market integration.

Policy Implications

The policy recommendations of this study are summarised below. These policy implications are fabricated by the author alone.

- TSOs should consider ways to account for the 70%-rule at a more proactive stage.
- Redispatch should continue to be used exclusively as a short-term solution for structural congestions, as TSOs should prioritise the expansion of grid capacity where there is a high marginal benefit to expansion.
- TSOs should incorporate the uncertainty and variable costs of redispatching congestions when evaluating grid investments and bidding zone reconfigurations.
- TSOs should continute looking for ways to incentivise electricity generation in deficit areas to reduce geographical supply-demand asymmetries, promoting more efficient usage of the grid.
- Energy Regulators and TSOs should continue to cooperate for promoting demand-side flexibility to make demand more responsive. This is not directly related to the study but is expected to decrease the rate of congestion, which leads to lower redispatch costs. DLR is another example of alternative methods to consider.

8 References

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A Appendix

A.1 Redispatch, Countertrading, and Curtailment

These three concepts are defined as redispatch in this study because the economic implications are very similar.

As stated in EP and Council (2019b) Article 35, redispatch may be used in the short- to medium-term to alleviate congestions before grid expansion is realised. The TSO may choose to activate either supply bids or demand bids, either at the intraday or balancing market.

- Up-regulating supply: The TSO activates a conventional generator in the deficit end to generate additional electricity, decreasing the overload. Up-regulation usually comes at a price above the day-ahead price, as generators with a lower marginal cost than the day-ahead price are dispatched at day-ahead price in normal circumstances.
- Down-regulating, or curtailing, supply: The TSO activates a generator in the excess end to reduce the overload. Down-regulation is usually procured at a price below the day-ahead market price. For down-regulation of conventional generators, the TSO pays the generator at most the sum of avoided start-up costs, non-used fuels, and CO2-eq emissions.

Countertrading is sometimes regarded as a separate type of remedial action, despite being technically the same as redispatch. Both actions concerns up- and down regulation to alleviate congestion while keeping grid frequency intact. Countertrading may be classed as a less precision-conditional type of redispatch. In the electricity regulation, countertrading is defined as "a cross-zonal exchange initiated by system operators between two bidding zones to relieve physical congestion" (EP and Council, 2019d), typically used when there are several congested lines between two bidding zones. The distinction is fairly irrelevant for the Swedish context. For example, if North and South in fig. 9 represent two Swedish bidding zones, it is countertrading, but if North and South are both within the same Swedish bidding zone, it is not countertrading but redispatch by this definition. In fact, in Sweden, the term *mothandel* usually refers to redispatch and countertrading collectively.

Curtailment is down-regulation of renewable intermittent supply, where the TSO pays the generator for the foregone financial support for renewables. When the TSO down-regulates, the cheapest options are often provided by renewables, since their MC is lower and responsiveness higher than conventional generators. From a welfare perspective, the increasing prevalence of curtailment has a double negative welfare impact. First, it costs money from the TSO that could have been allocated to long-term alleviation like grid investments. Second, it decreases the share of renewables at final dispatch, leading to higher CO2-eq emissions per kWh. However, down-regulating conventional generators is often much more expensive given their higher merit order, often leaving curtailment as the preferred option for down-regulation. Curtailment has caught media attention with Financial Times reporting that ten percent of British wind output and five percent of German renewables were curtailed in 2024 (Bernard and Millard, 2025). (Energimarknadsinspektionen, 2022) expects curtailment to increase with increasing share of renewables. A growing share of wind power in Ireland, a country with relatively limited export capacities, has forced the Irish TSO to curtail wind generators more often as wind power surges (Holmberg and Tangerås, 2024, p.4).

Redispatch is typically realised on the generation side, but may also involve demand-side resources where available. While demand-side participation is still limited in most European markets, it is gaining attention as a potential contributor to congestion management and system balancing (Energimarknadsinspektionen, 2024; Rövekamp et al., 2023). Demand-side flexibility may provide down-regulation (load reduction) services, especially from large industrial consumers.

A.2 Ongoing grid expansion

A range of efforts to enhance capacity and increase efficiency in the grid are underway. On the European level, the *Ten Year Network Development Plan*, developed by European Network of Transmission System Operators for electricity (ENTSO-E, 2025b), identifies cross-border projects that may contribute most to overall welfare. The report serves as basis for selecting multinational *Projects of Common Interest* (PCI), that are supported and financed by the EU. For more information, see the projects map at ENTSO-E (2025b). Eurelectric (2024a, p.19) show that annual nominal investments in EU27 and Norway may need to double from today's level at 36 billion Euro to 67 billion Euro. (Heussaff and Zachmann, 2025, p.7) provide a list of future grid investment assessments from various agencies, with all of them estimating European grid investments of over 400 billion Euros from 2022 to 2030, significantly increasing market integration in the European Union.

In Sweden Svenska Kraftnät (2025c, p.10) expects grid investments to exceed 20 billion SEK in 2027, more than two-fold from 2024 levels, after hovering below 5 billion SEK since 2013. The TSO identifies four main drivers for transmission grid expansion in their network development plan Svenska Kraftnät (2024b, pp.9-16): Reinvestments to maintain the existing grid, accommodating new connection needs, reinforcement of the existing grid system, and cross-zonal integration with neighbouring bidding zones. A historical renovation rate coincides with large expansion, as half of Sweden's power stations and 2500km of transmission lines need renovation within the next 10 years. See Svenska Kraftnät (2024b) for their ongoing grid investments in Sweden. The plan involves several assessments of prioritised grid developments including reinforcement of frequently congested grid sections, where the welfare beenfit is expected to be the highest Svenska Kraftnät (2024b, pp.9-15). However, these investments take time to realise. Svenska Kraftnät aims to halve lead times for grid expansions from 15 to 7 years (Svenska Kraftnät, 2024b, pp.20, 31). Regardless of the welfare savings from grid investments, an interim solution like redispatch is needed in the meantime.

A.3 Ongoing EU electricity market integration

Guided by the EU legislations, the integration of European electricity markets is multifaceted. Market coupling through cross-zonal trading is promoted by initiatives like the cooperation mechanisms of Single Day-Ahead Coupling and Single Intra-Day Coupling. The CACM Regulation also provides much reference for increased market integration, including the flow-based market coupling optimisation method. European organisation ENTSO-E coordinates cross-zonal operations and capacity allocation, while Regional Coordination Centres support real-time operation, balancing, and risk assessment. Moreover, relatively new interconnectors connecting bidding zones overseas enable more market integration for the British Isles, Nordic, and Baltic regions who were separated from mainland Europe by water. Many of these interconnectors can transmit up to 1,400 MW, roughly equivalent to a large-sized nuclear power plant[21]. Under Article 16(8) of Regulation 2019/943, TSOs must ensure that at least 70% of the capacity on critical network elements is made available for cross-zonal trade. While this does not guarantee that 980 MW (70% of 1400 MW) will always be tradable, the rule increases pressure on TSOs to prioritize cross-zonal exchange, which may reduce the capacity left for internal flows.

Two European Union bodies are set out to coordinate and harmonise electricity markets and regulations across the EU. The *European Network of Transmission System Operators* (ENTSO-E) are responsible to coordinate cooperation between European TSOs. The primary function of ENTSO-E is to ensure an efficient, transparent and well-integrated European electricity grid, regulated by 2019/943 (EP and Council, 2019d). Meanwhile, The *Agency for the Cooperation of Energy Regulators'* (ACER) primary objective revolve around overseeing and coordinating electricity market regulation in the EU, regulated by 2019/942 (EP and Council, 2019a).

The EU Regulation 2015/1222 (European Commission, 2015) introduced EU-wide rules for capacity allocation and congestion management (*CACM*), aligning the electricity market with the EU Single Market concept. It promotes integration of intra-day and spot markets across Europe by Articles 6 and 7. Additionally, article 20 in the CACM Regulation enforces the adoption of the Flow-Based Market Coupling (FBMC) method, to optimise congestion management. A number of studies verify FBMC to improve overall welfare (Bucksteeg et al., 2024; Makrygiorgou et al., 2020; Van den Bergh, Boury, and Delarue, 2016). Note that Flow-Based Market Coupling sometimes can give rise to counter-intuitive flows, where electricity flows from a bidding zone with higher price level to a bidding zone with lower price, as part of the overall optimisation (Van den Bergh, Boury, and Delarue, 2016, p.10). While centrally located countries like Germany and France implemented FBMC immediately, Europe-wide adoption has been gradual. In October 2024, the Nordic countries (Sweden, Norway, Finland, Denmark) implemented FBMC.

The ongoing market integration faces increasing resistance throughout the EU, plus interconnected countries like Norway, Switzerland, and the United Kingdom. Financial Times report that the Greek prime minister Mitsotakis criticised the EU electricity market for lack of transparency and inexplicably high prices Hancock and Milne, 2024. Note-worthily, the scepticism comes mainly from net-exporting countries whose consumers fear that market integration marks an end to a long history of stable and low prices. Reuters and Financial Times report that the Norwegian ruling coalition fell apart December 2024 in a schism over adoption of EU energy policies (Milne, 2024; Milne, 2025; Solsvik, 2025). The Norwegian finance minister opposed the adoption and left the coalition, claiming that EU market integration regulations exacerbate Norwegian electricity prices(Milne, 2025). In concern for domestic electricity price stability,

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[21] Oskarshamn 3 has a capacity of 1450 MW

The Swedish Government state that additional interconnectors to Europe may jeopardise domestic price stability (Sveriges Regering, 2024, p.34). The Swedish government forestalled the planned construction of the Swedish-German 700 MW interconnector *Hansa Power Bridge*, on the grounds that Germany needs to reform their electricity market (Hancock and Milne, 2024).

A.4 Climate change and the electricity sector

The electricity sector is the largest emitting sector globally, standing for 36% of total CO2-eq emissions in 2024 (IEA, 2024b, p.121). With such a large impact, climate change mitigation relies much on the progress of the Energy Transition in the global electricity sector. IEA report that climate change is already having pronounced impacts on the energy markets worldwide. As climate change exacerbates extreme weather events like floods, droughts, storms, and heat waves, the ensuing costs of these events are likely to continue rising (IEA, 2024b, p.234). The supply and demand are also impacted by climate change in certain cases. For example, over $40 billion worth of power is lost due to two climate-change augmented factors alone: changing precipitation patterns, which reduce global hydropower generation, and more severe heatwaves, increasing global electricity demand for cooling (IEA, 2024b, p.234). The AR6 report from Intergovernmental Panel on Climate Change (IPCC) presents consensus-based estimations on the impacts, risks, and policy recommendations connected to climate change (IPCC et al., 2023). In summation, the potential future costs of climate change are looming large, as researchers have high confidence that damages to infrastructure, human health, and property increase non-linearly with global warming levels (IPCC et al., 2023, B.2.2 and B.7). Infrastructure system costs caused by climate-change has been observed and will likely continue rising (IPCC et al., 2023, A.2.6 and B.2.1). The IPCC et al. (2023, p. C.3.2) also presents mitigation and adaptation options, with improved grid system capacity and robustness being among the proposed actions.

To mitigate the future risks and costs associated with climate change, the European Commission has committed that the Union be climate neutral by 2050, via the broader *Green Deal* package (European Commission, 2021). Likewise, Swedish climate objectives strive for 100% fossil-free energy usage by 2040, followed by a net-zero emissions target by 2045 Energimyndigheten (2024, p.14). *Fit For 55* binds EU members to at least 45% renewable electricity by 2030, and an array of sector-specific objectives (European Council, 2025). These European climate goals are reflected in Regulations and Directives. For example, the Emissions Trading System (ETS) internalises the externalities of CO2-eq emissions from electricity generators, thereby nudging profitability towards non-fossil fuelled electricity generation. Another example is the Renewable Energy Directive which improves market conditions for renewable electricity generation (EP and Council, 2018). In Sweden, Proposition 2023/24:105 provides the energy policies of the current parliament (Sveriges Regering, 2024). The main points include enhancing generation and grid infrastructure, increasing grid user flexibility & security of supply, and promoting industry electrification & decarbonisation (IEA, 2024a). Read more about climate policies in the Swedish context at Energimyndigheten (2022, pp.94-99) and Sveriges Regering (2024).

A.5 Definition of Welfare in the electricity market context

In economics, *welfare* is typically associated with the allocation of resources that maximises aggregate utility or societal well-being. However, the input for additional electricity generation may bear externalities. In economic theory, the welfare concept revolves around maximising long-term utility for the individuals, including the social, economical, and environmental aspects. Welfare goes beyond the benefits and costs of a good (service, commodity, or product) to account for externalities; a cost or benefit which affects someone other than the actor, not captured in market prices. Since a typical seller of a good often base their selling price on private costs, the true societal costs are not always fully internalised in their selling price (Pigou, 2017, p.54). Likewise, the consumer do not always estimate the true societal cost of the good in their perceived utility valuation of a good. Hence, externalities may be seen as market failures which the invisible hand of the market does not fully account for, since neither the seller nor the buyer internalise these costs in their bids on the electricity market. Nordhaus (2019) argues that internalising climate change costs (e.g. by carbon pricing), is crucial to ensure long-term welfare. As discussed in the Dasgupta review (2021, Chapter 7, p.194), a well-functioning market should internalise externalities. On a similar line of argument, (Le Coq et al., 2025, p.16) writes that electricity prices should, on the one hand reflect the utility pertaining to electricity generation, transmission, and consumption, on the other hand reflect the costs incurred on society. In this way, the authors propose that ecological and societal values align with economic values.

However, in the context of electricity market design, welfare is increasingly evaluated based on a wider range of factors. Policy frameworks, such as the United Nations' Agenda 2030, conceptualise welfare through three dimensions: economic, environmental, and social sustainability (UN, 2025). While these three objectives are traditionally viewed as pillars of sustainability, they also align closely with long-term welfare in energy systems.

One of the UN's goals involves to "ensure access to affordable, reliable, sustainable, and modern energy for all" UN (2025), which combines economic affordability, environmental transition, and the social value of reliable access. This multi-dimensional view is reflected in Swedish energy policy as well, where current national objectives are defined as security of supply, competitiveness, and ecological sustainability Sveriges Regering (2024, p.57). Svenska Kraftnät shares that: "The challenge is to find optimal socio-economical solutions that ensure the power system remains stable while meeting future electricity demands at the right time [security of supply] and aligning with the need for an energy transition" (Svenska Kraftnät, 2024c, p.7).

In light of the common emphasis on *Security of supply*, it may represent a crucial aspect of social well-being, since reliable and affordable electricity access is foundational for households, industries, and the public sector. Therefore, in this study, *welfare* is defined as an outcome that considers economic efficiency, environmental impact, and the societal benefits of supply reliability. This definition reflects both the evolving policy landscape and the complex trade-offs in designing electricity market systems.

A.6 About electricity market price, dynamics, and its seasonal cycle

The electricity market has some unique characteristics that deviate from typical market dynamics in economic theory. Figure A1 visualises the average weighted bidding curves in Sweden in 2024. Actors may bid between -500€/MWh[22] and +4000€/MWh Nord Pool (2025). To visualise the bid curves in more detail, fig. A1 is rescaled with a hyperbolic sine transformation in fig. A2.

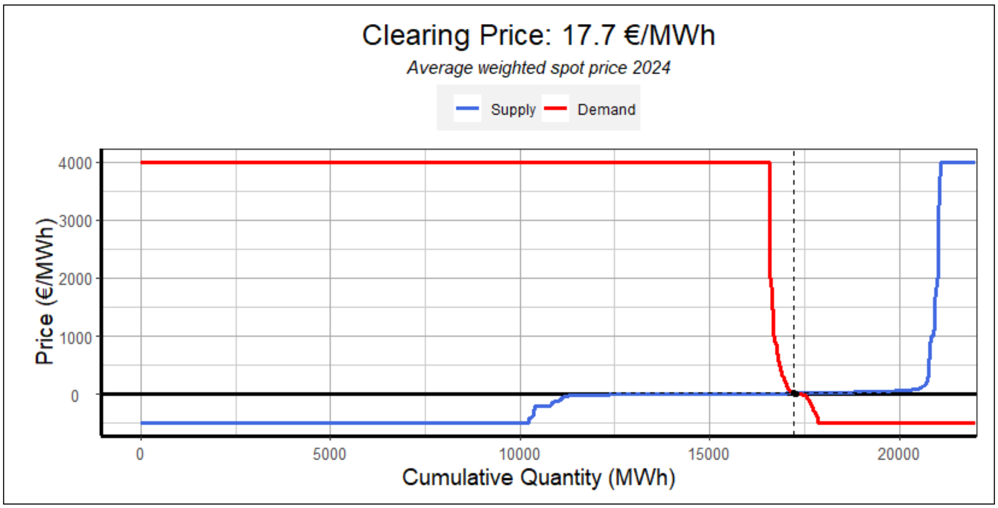

Figure A1: The curves represent the average supply and demand bids (day-ahead) in Sweden (SE1, SE2, SE3, SE4) during 2024.

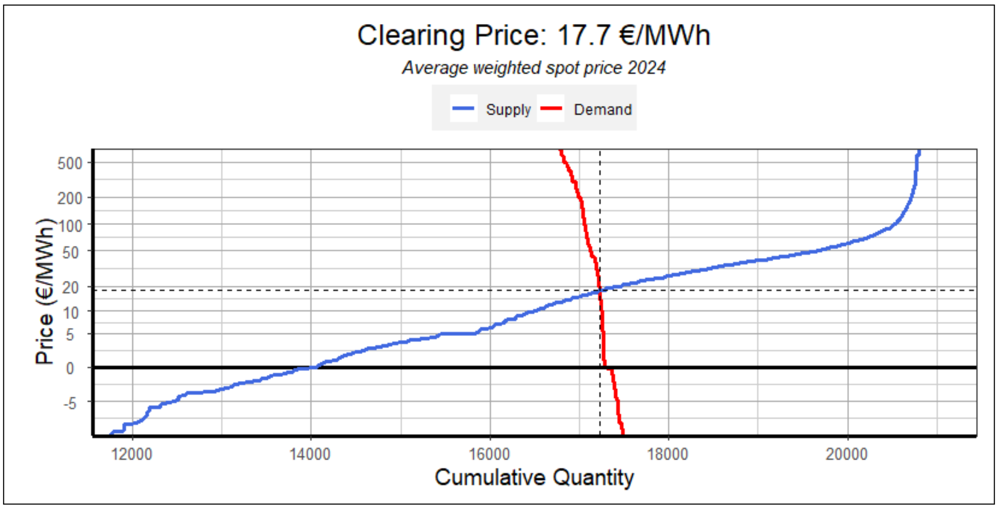

Figure A2: The curves represent the average supply and demand bids (day-ahead) in Sweden (SE1, SE2, SE3, SE4) during 2024. The graph is rescaled with hyperbolic sine transformation to better visualise the bidding curves close to zero.

The supply curve caps at minimum price up to a certain quantity, then rises towards zero, flattens out around prices close to zero, and continues with a slight increase up to a certain quantity, whereafter price increases exponentially to the maximum price. Negative price bids, where $P < 0$, represent generators whose opportunity cost to producing is higher than their marginal cost. Zero-price bids, where $P = 0$, usually represent generators whose generation is

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[22] The report by (Eurelectric, 2024b) presents a discussion on negative prices, which mainly appears when there is electricity surplus and subsidized plants become price setters.

more or less *must-run*. For bids where $P > 0$, bids slightly above zero may originate from low marginal cost generators, typically renewable electricity generators. The higher the bids, the higher on the merit order and lower the chance to get dispatched at clearing price.

Electricity demand curves are in general more steep and inflexible than the supply curve, as seen on the average curve of 2024 in fig. A2. The demand curve is flat at the capped maximum price level of €4 000 up to a certain quantity, whereafter it drops abruptly towards towards near-zero, flattens out slightly and then continues dropping into the negative prices, capping at -€500. The majority of demand bids are set at maximum price, €4 000, referred to as *inflexible* consumption. As consumers in theory bid at or below their marginal utility of electricity, MB, the lion's share of electricity is theoretically perfectly inelastic to electricity price; electricity which must always be dispatched to avoid large economic damage.

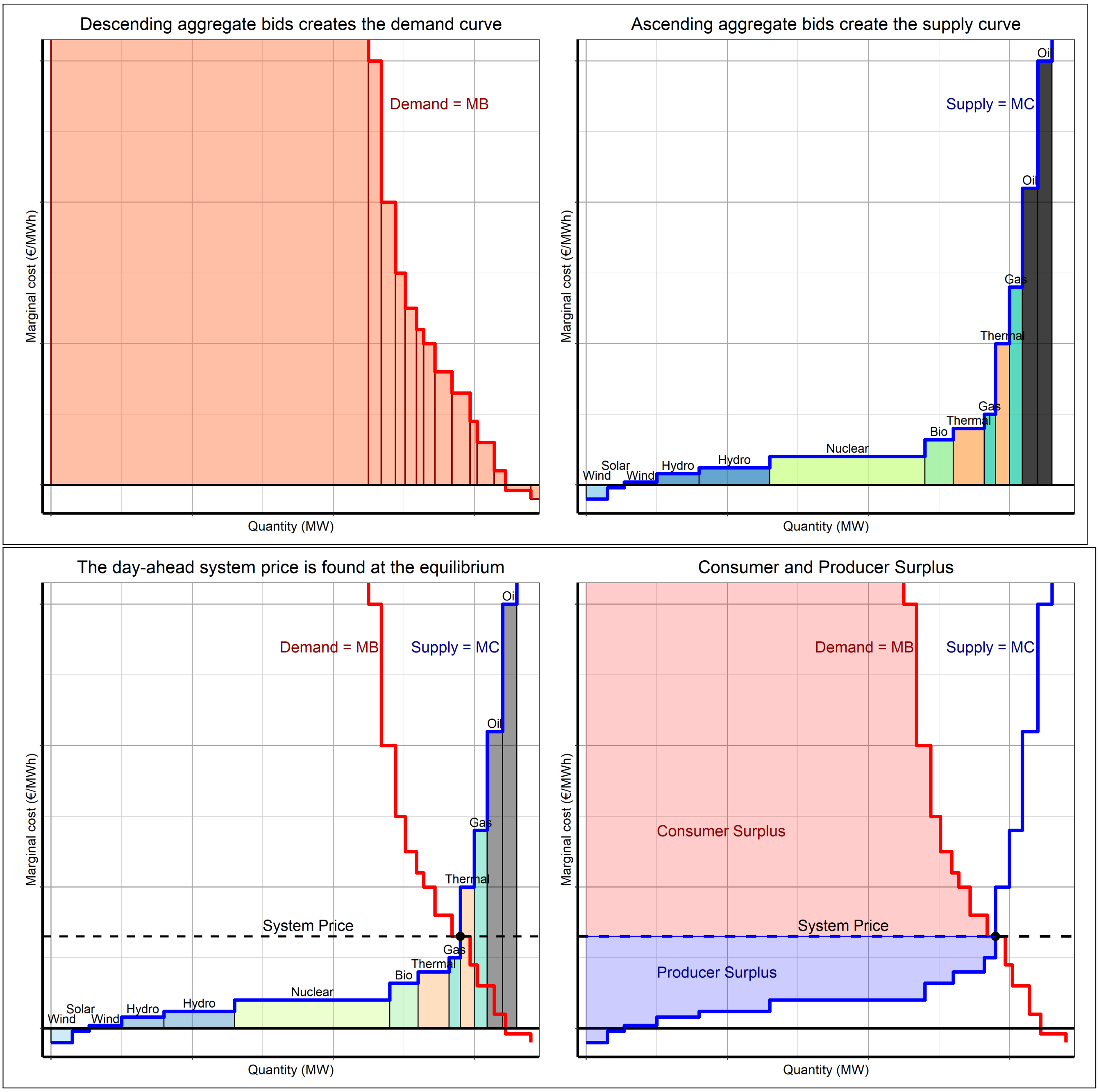

Figure A3: A simplified illustration of market clearing and the resulting producer and consumer surplus. This is done within each bidding zone to find the spot price.

Figure A3 illustrates how bids are compiled in price order and consequently matched to find a clearing price. For spot price, capacity calculations are accounted but the concept is similar. The supply curve presents the merit order, with low marginal cost generators first in the merit order, meaning they are dispatched more often. The resulting consumer and producer surplus are illustrated in the bottom right graph.

A.6.1 Seasonal cycles

The electricity demand and supply have yearly and daily cycles due to consumption patterns. The seasonal cycle is driven by temperature, driving an equally strong seasonality in supply. Figure A4 and fig. A5 represent the supply and demand an average[23] hour during summer and winter, respectively. The extra demand in wintertime stems mostly from heating buildings. In the Swedish context, the high share of hydropower means generators are augmenting when demand is high and withholding supply when demand is low. The result is similar average prices regardless of the week. In effect, comparing fig. A4 to fig. A5, parts of the extended low-price bids in the winter comes from hydropower. The average volume of electricity traded in Sweden ranges from 15 000 MW during summer (week 28), to around 22 000 MW during winter (week 3). During 2024, the hourly consumption in Sweden ranged between 8 300 MW to 25 200 MW (Nord Pool, 2025).

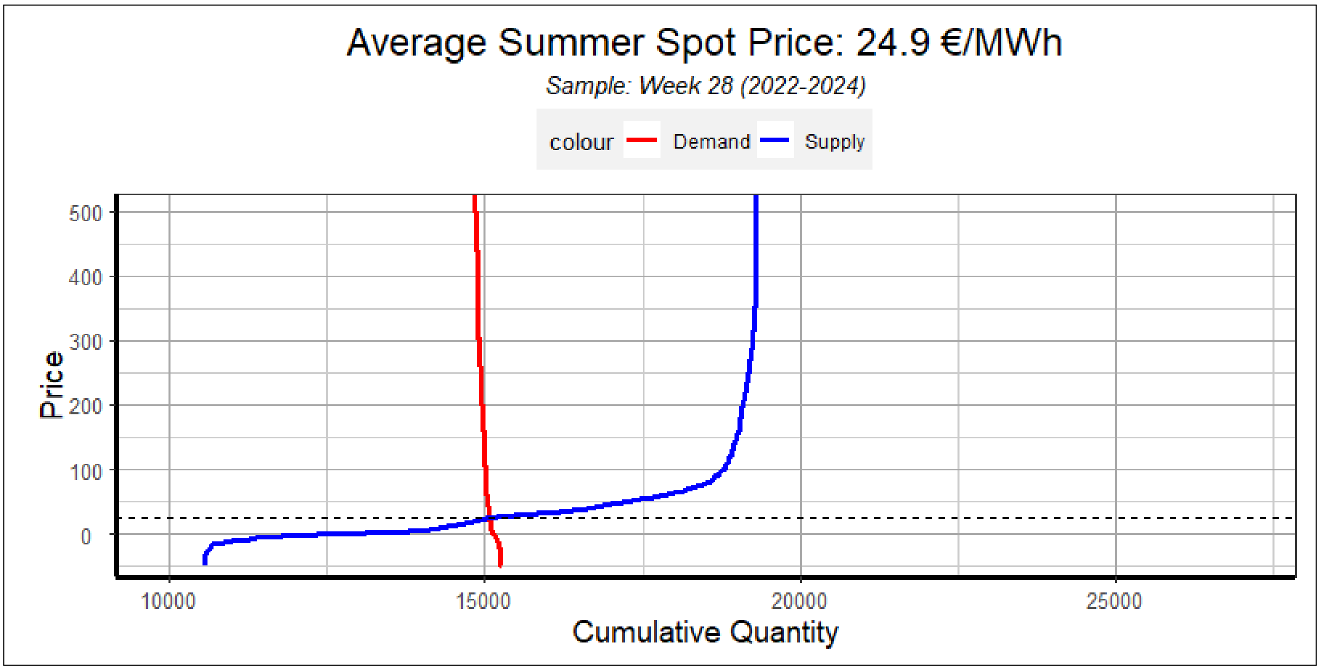

Figure A4: Average spot price during summer. The graph is based on proprietary data sourced from Nord Pool (2025), processed by the author.

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[23] The *Winter* graph is based on hourly data from every day in week 3 (2022-2025), totally 252 hours. The *summer* graph is based on hourly data from every day in week 28 (2022-2024), totally 336. I assume these weeks reflect midwinter and midsummer demand and supply well.

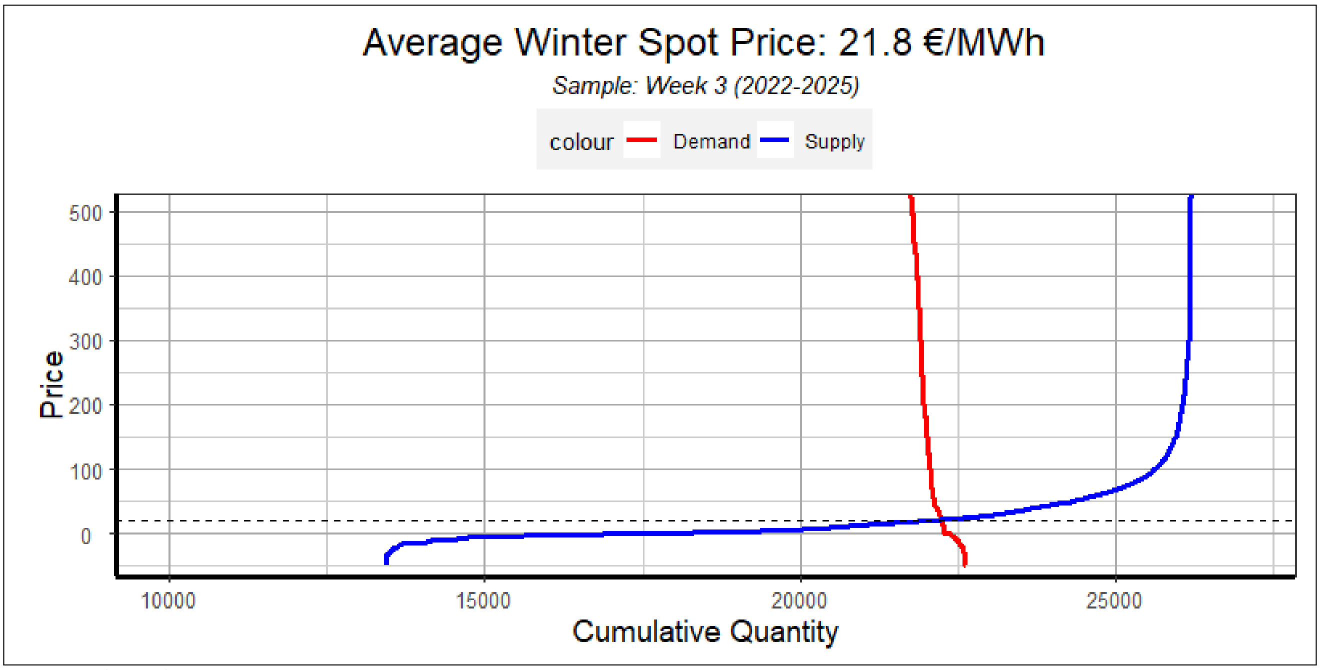

Figure A5: Average spot price during winter. The graph is based on proprietary data sourced from Nord Pool (2025), processed by the author.

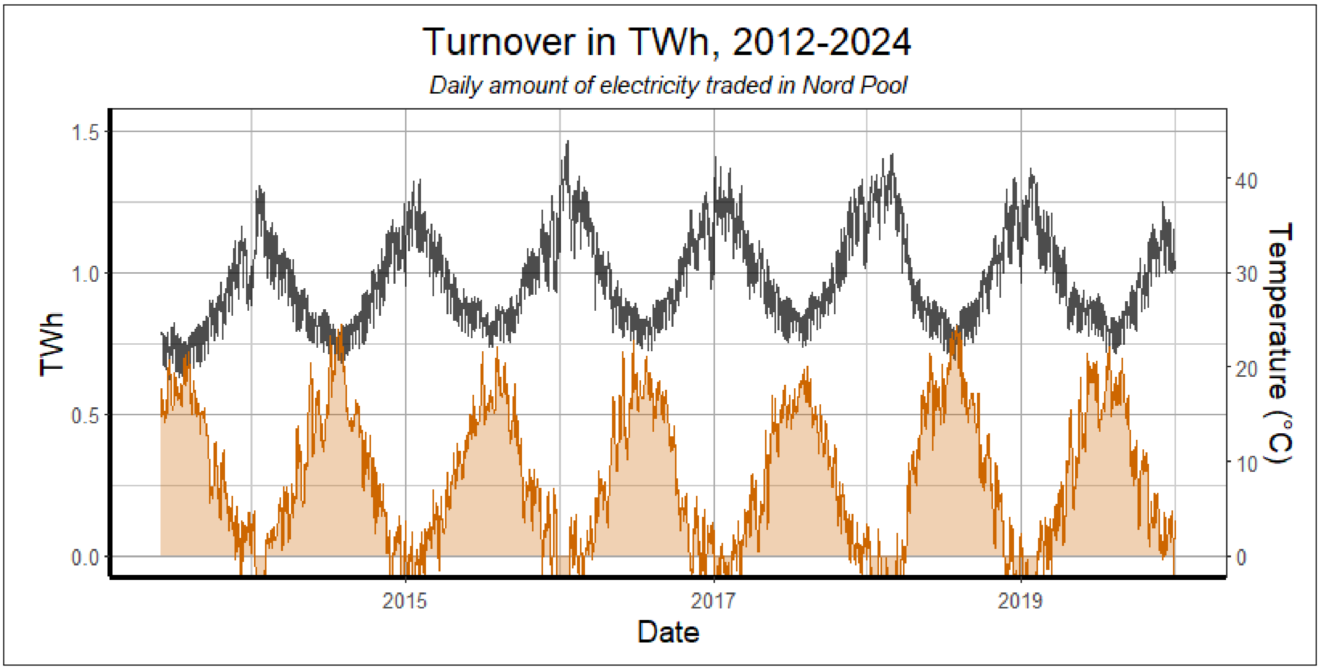

Figure A6: The daily turnover and daily temperature have a strong correlation. Data from Nord Pool (2025) and SMHI

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A.7 Alternative methods to abate congestions

Listed below are various methods for preventing or otherwise abating congestions. These are listed for the reader's interest; they are not part of this study.

- *Grid topology measures*, such as line switching, flow redirection, or the use of phase-shifting transformers, adjust flows by altering the grid's physical configuration. These actions typically incur low direct operational cost and are therefore often prioritised over redispatch. However, due to technical and operational constraints, many topology-based actions are implemented ahead of real-time and may not be feasible or available at the delivery hour. This study focuses on real-time market-based interventions, so these actions are out of the scope of this study.

- *Dynamic bidding zones:* Risanger et al. (2025, p.11) develop a method where bidding zones are dynamic. By changing zones according to congestions at the day-ahead dispatch, the redispatch needs are minimised. While this method may minimise redispatch costs, it may lead to a lower degree of market integration and significant operational costs.
- *Dispatch hubs:* The Belgian TSO Elia (2019, pp.23-26) propose dispatch hubs as a midway solution to uniform and zonal pricing. Dispatch hubs are small bidding zones encircling strategical areas with balancing resources. They argue the solution may provide a better political prospect than zonal pricing, as the dispatch hubs would encircle supply centres, maintaining uniform pricing for consumers but also providing locational incentivisation for generators. The uniform versus zonal trade-off is discussed by Ahlqvist et al. (2022) and Eicke and Schittekatte (2022).
- Modifying capacity allocation: Van den Bergh, Couckuyt, et al. (2015) suggest that relaxing the N-1 security criterion in the day-ahead market could reduce redispatch costs by a factor of eight as it increases the F_{RAM}. However, this increases operational risk, particularly if multiple critical grid elements fail within a short time. Similarly, Oggioni and Smeers (2013) highlight that transmission capacity allocation is a key driver of redispatch costs, but removing security margins often expose the operator to risk of grid failure. As an alternative, Wallnerstrom et al. (2014) propose dynamic line rating (DLR) as a way to increase the F_{RAM} without significantly compromising security. Since thermal transmission capacity rises in colder temperatures, it allows higher flow limits in winter, when demand is higher, thereby reducing congestion and potentially yielding substantial welfare gains. Svenska kraftnät is currently evaluating the implementation of DLR.
- Green hydrogen, produced when electricity prices are low and used as a substitute to electricity when prices are high, presents an opportune tool for the future electricity markets. IEA (2024a, pp.57-64) and Sveriges Regering (2024, p.51) highlight hydrogen as an important commodity for decarbonisation and demand flexibility.
- Flexibility markets: Consumers may voluntarily reduce consumption in exchange of monetary compensation. Flexibility market projects are underway several regions, possibly reduces the need for redispatching in these areas (Holmberg, 2022, p.61). This could reduce price spikes and congestions. On a similar line, Holmberg (2022) notes that implementing more exposure of hourly spot price would increase the demand sensitivity. Voluntary down-regulation of demand could potentially replace up-regulation of supply to some extent. As part of the growing flexibility markets, there is an increasing number of battery electric vehicles available for bi-directional charging. In an Austrian case study by Golab et al. (2025, p.1), the redispatch costs could fall by up to 35% when integrating the entire Austrian EV fleet. While flexibility markets may not alleviate congestions in the same reliable way as redispatch, they assist in reducing the probability of congestion.

A.8 Figures

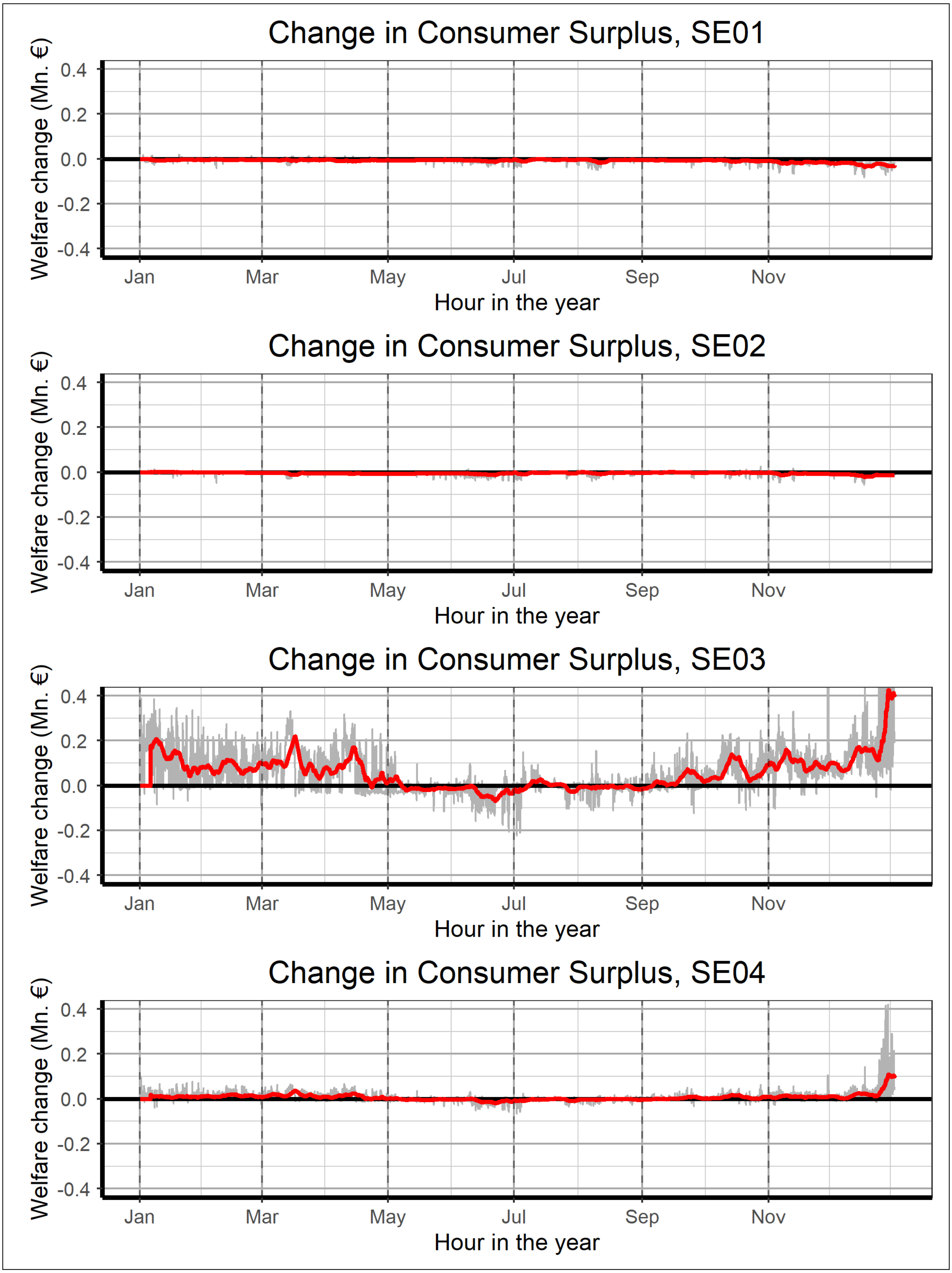


Figure A7: Change in total Consumer Surplus in each bidding zone from *disptach* to *redispatch*. The gray lines marks hourly values and the coloured line marks a 168-hour moving average.

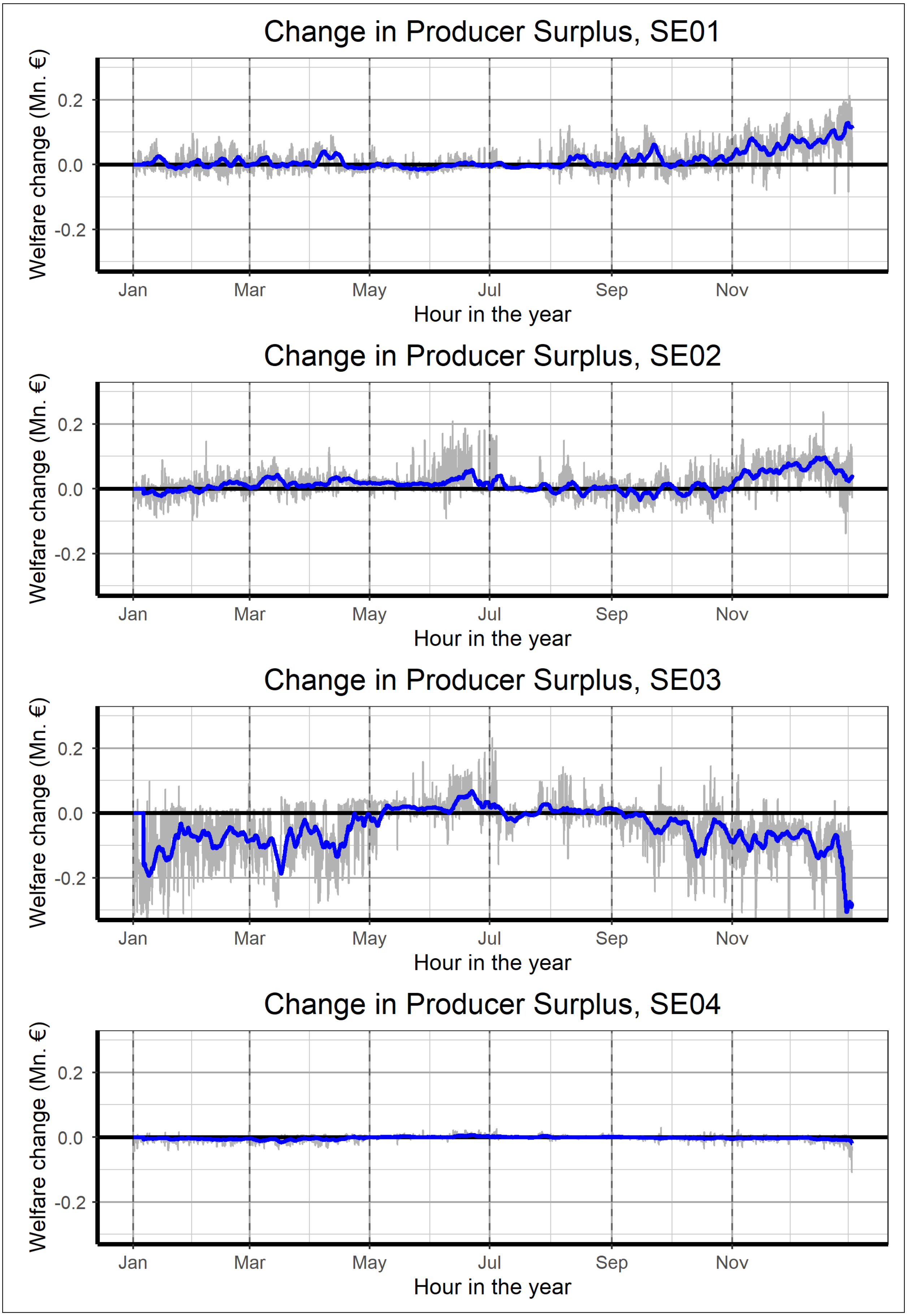


Figure A8: Change in total Producer Surplus in each bidding zone from *disptach* to *redispatch*. The gray lines marks hourly values and the coloured line marks a 168-hour moving average.

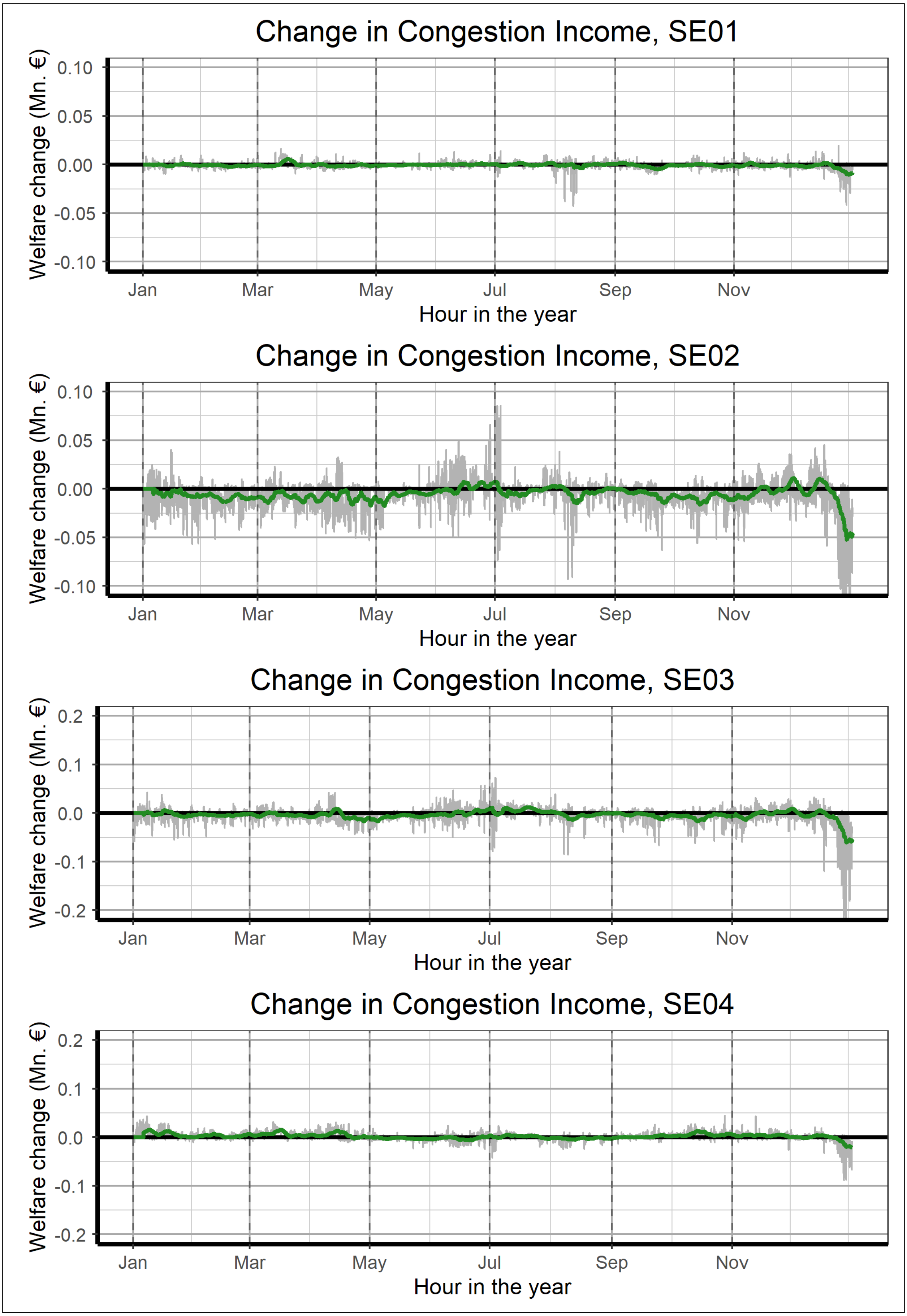


Figure A9: Change in total Congestion Rent in each bidding zone from *disptach* to *redispatch*. The gray lines marks hourly values and the coloured line marks a 168-hour moving average.

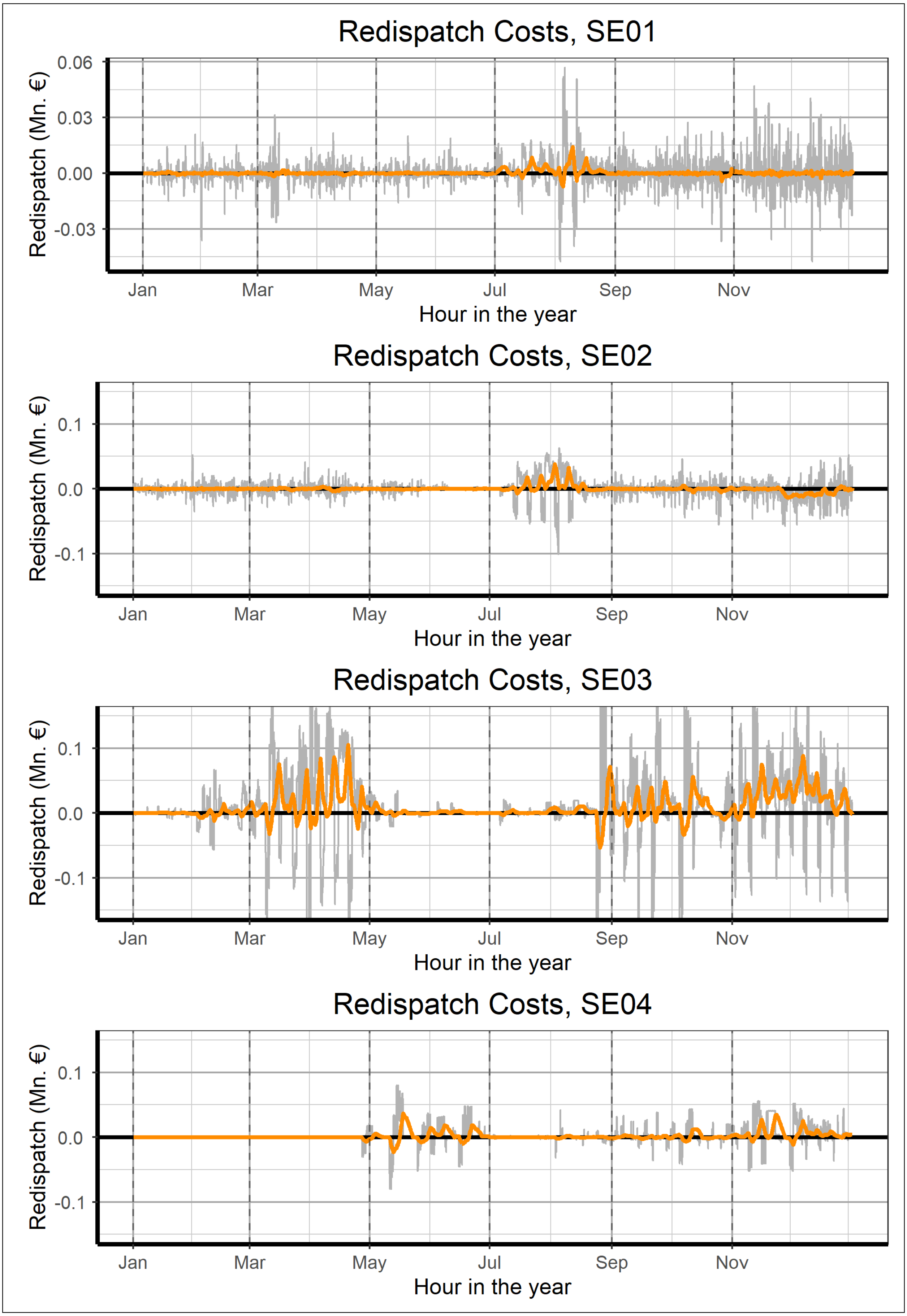


Figure A10: Total redispatch costs in each bidding zone.
The gray lines marks hourly values and the coloured line marks a 168-hour moving average.

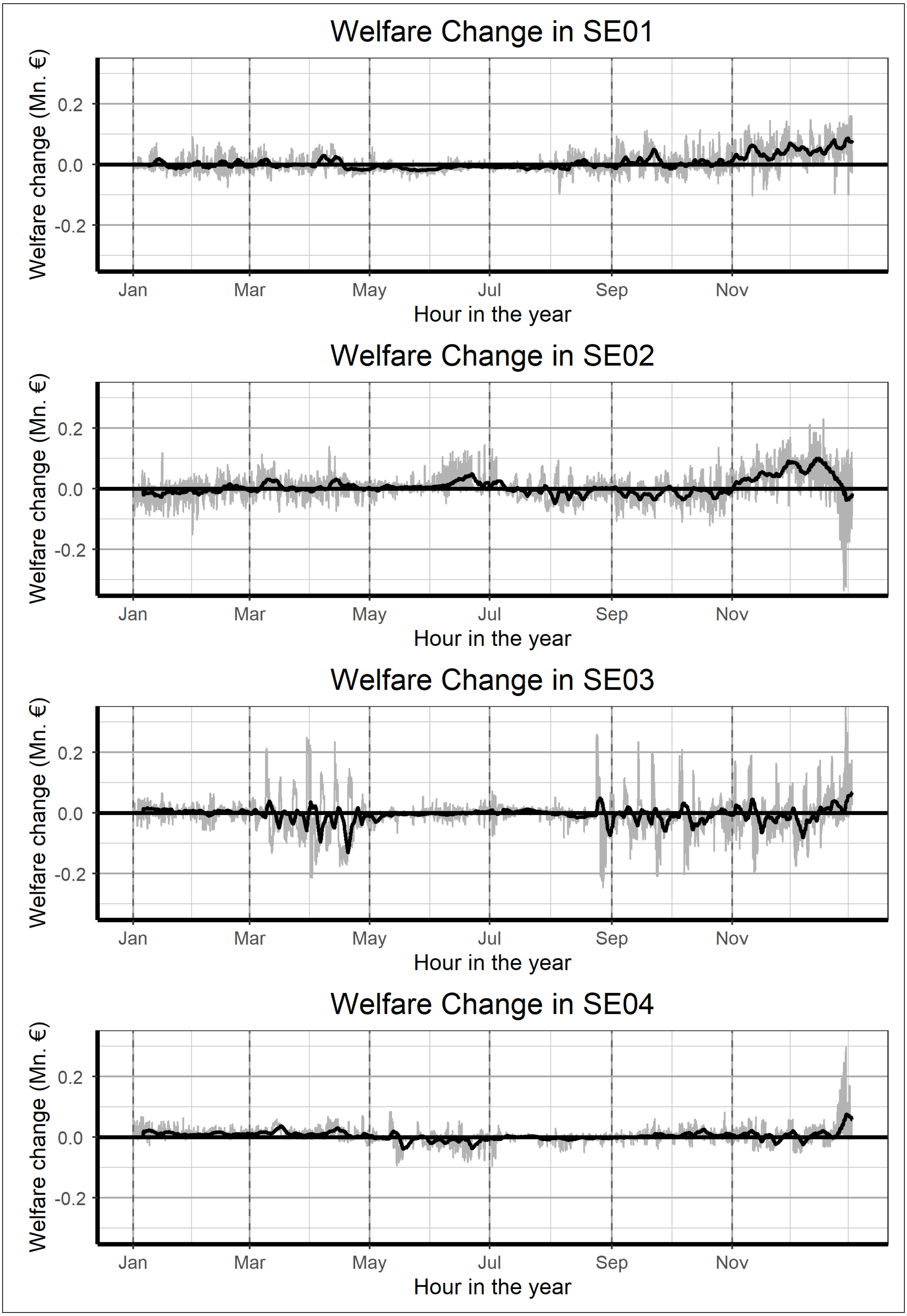


Figure A11: Time series of the change in EMU from *dispatch* to *redispatch*. The black line is a 168-hour moving average.

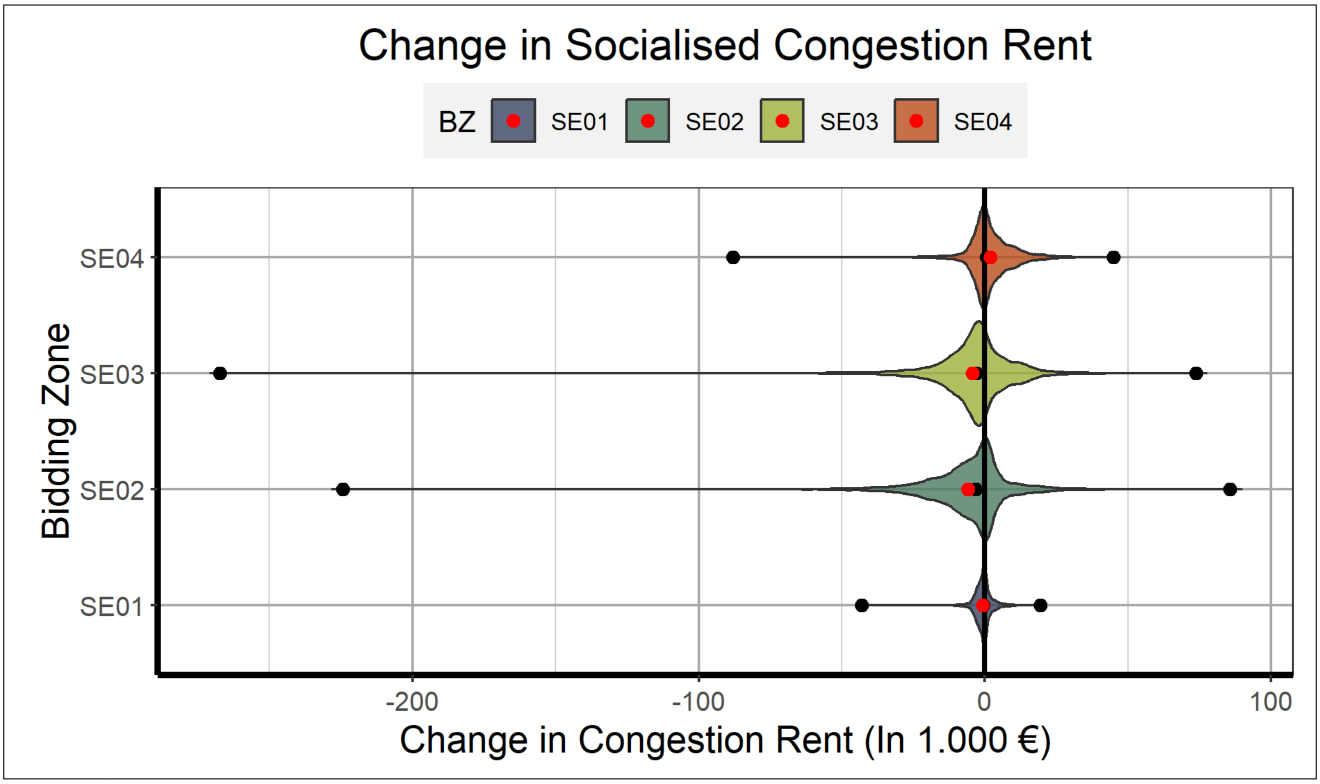


Figure A12: Violin plot of change in Congestion Rent, showing its distribution. Red dots indicate mean values.

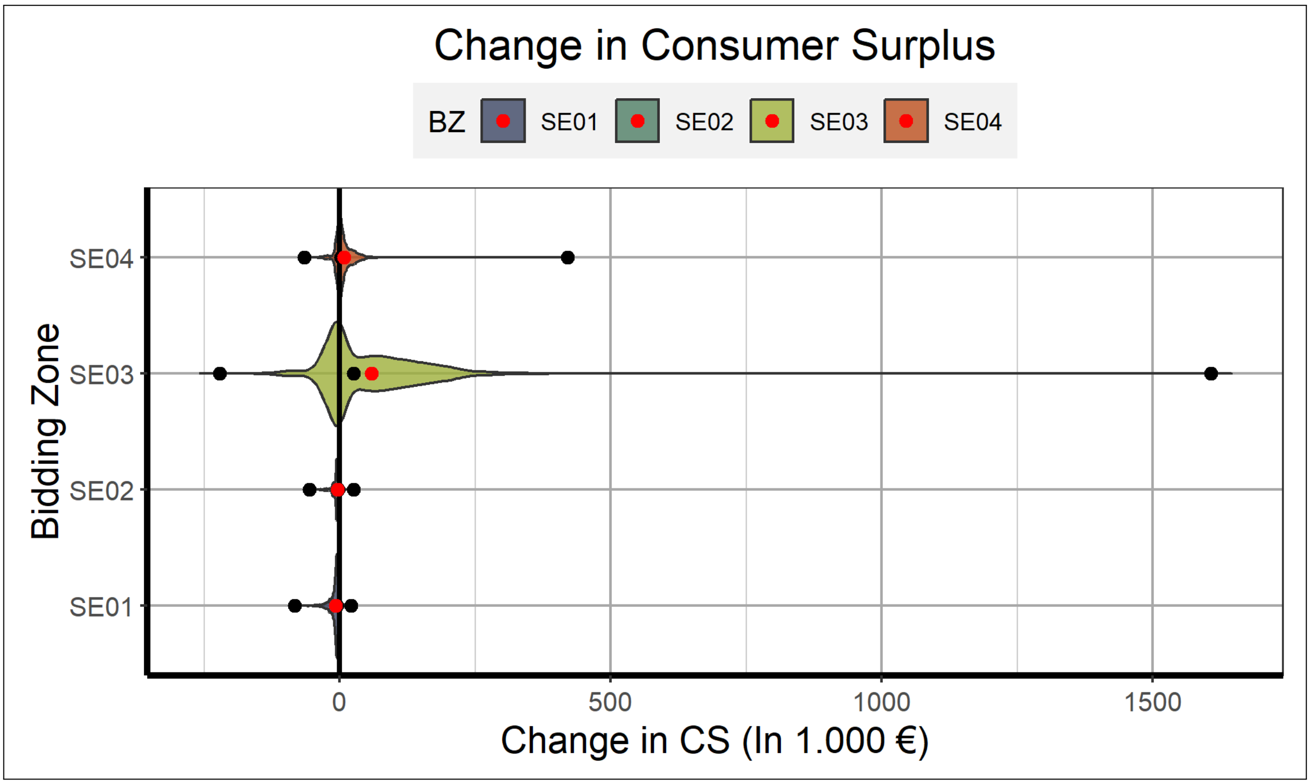


Figure A13: Violin plot of change in Consumer surplus, showing its distribution. Red dots indicate mean values.

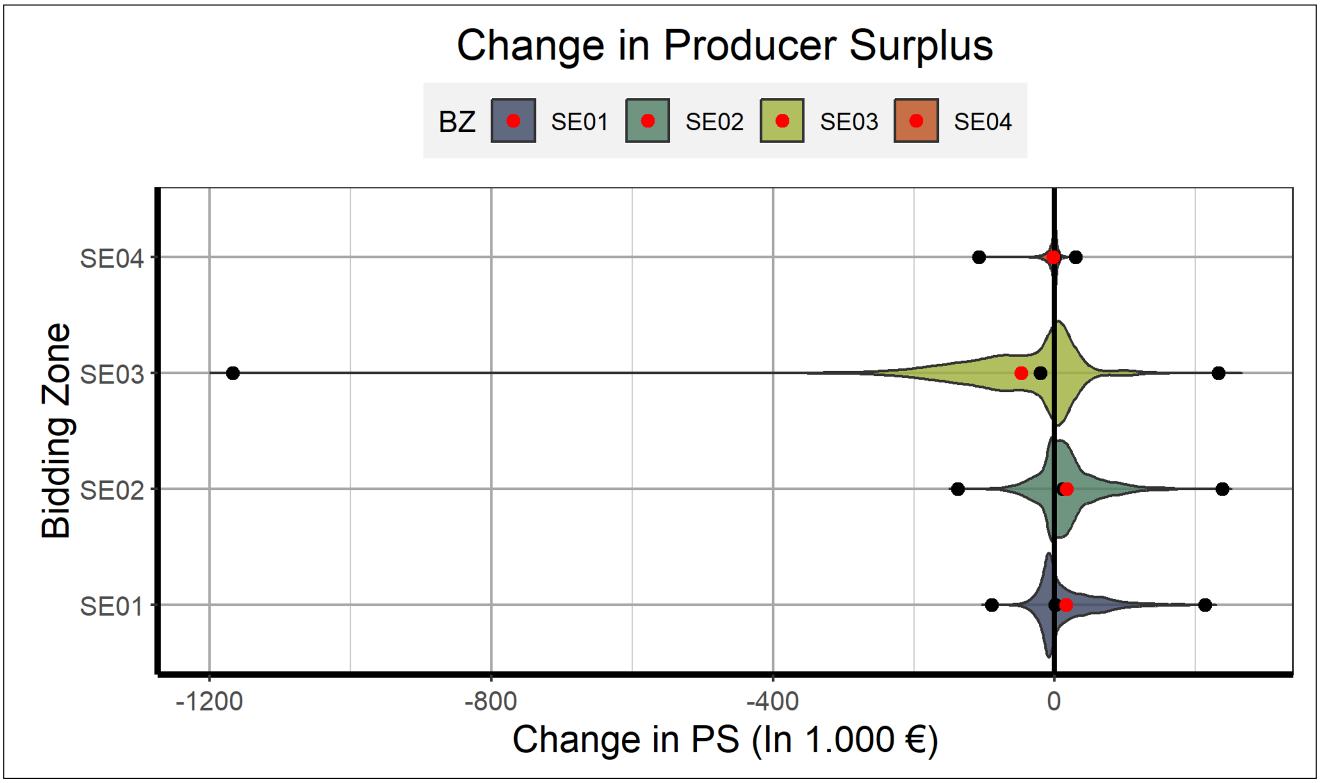


Figure A14: Violin plot of change in Producer surplus, showing its distribution. Red dots indicate mean values.

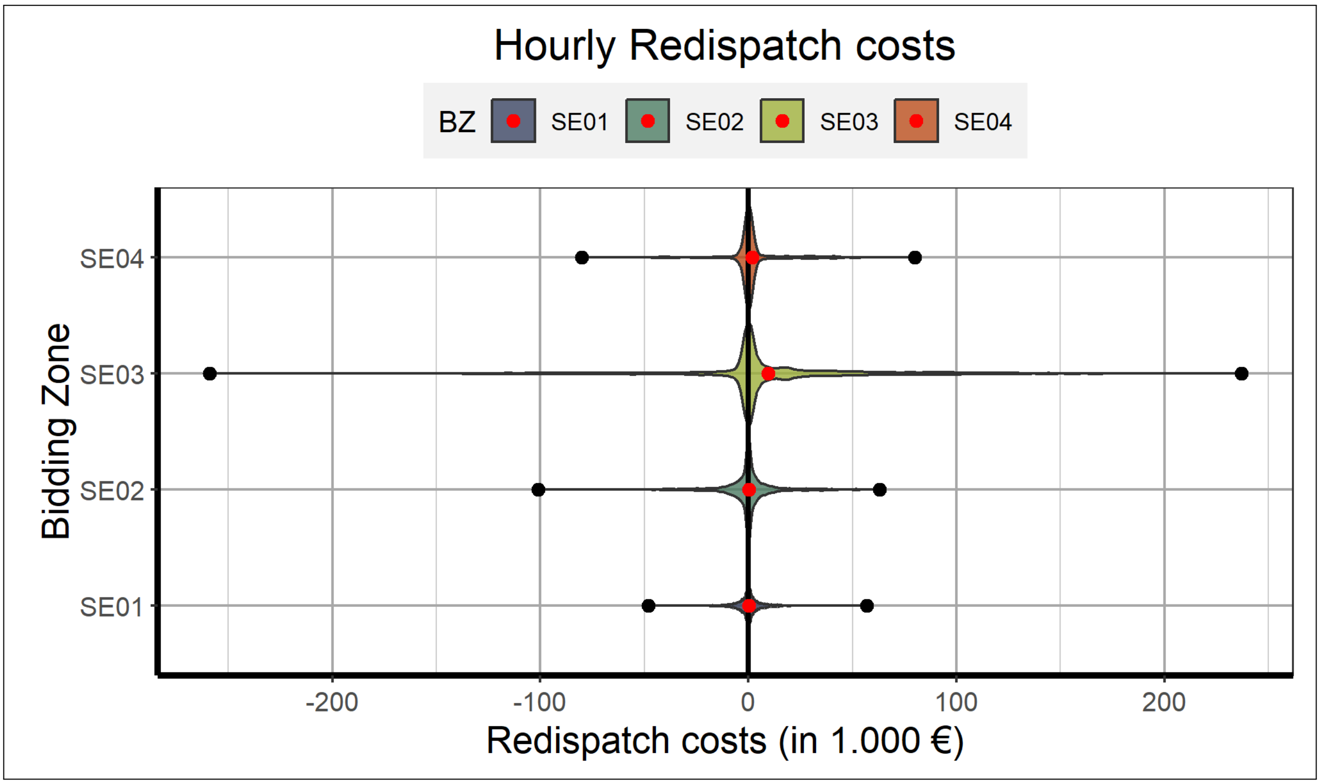
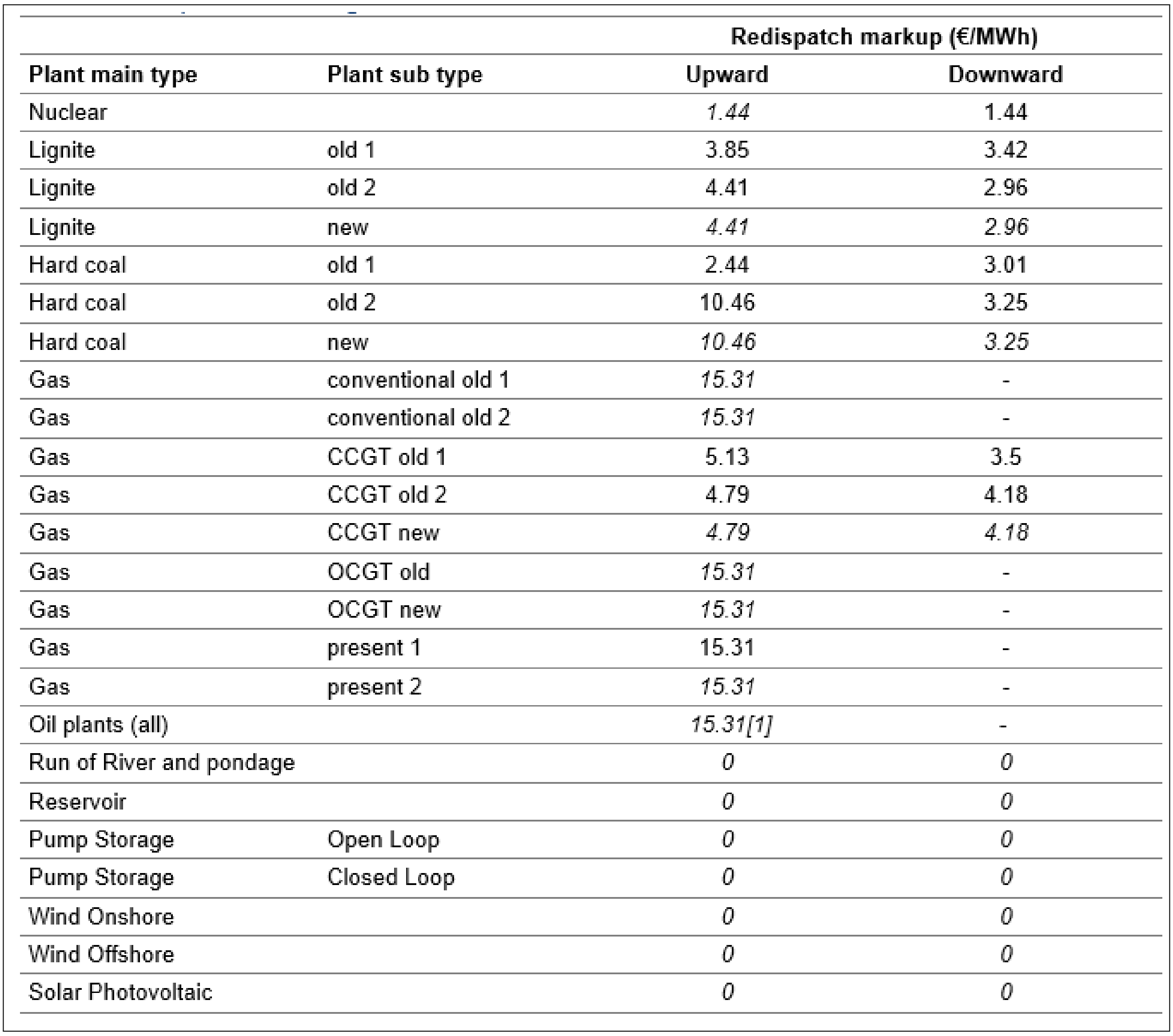


Figure A15: Violin plot of change in Redispatch Costs, showing its distribution. Red dots indicate mean values.

Table A1: Markups for each generator type in the simulation model



		Redispatch markup (€/MWh)	
Plant main type	**Plant sub type**	**Upward**	**Downward**
Nuclear		*1.44*	1.44
Lignite	old 1	3.85	3.42
Lignite	old 2	4.41	2.96
Lignite	new	*4.41*	*2.96*
Hard coal	old 1	2.44	3.01
Hard coal	old 2	10.46	3.25
Hard coal	new	*10.46*	*3.25*
Gas	conventional old 1	*15.31*	-
Gas	conventional old 2	*15.31*	-
Gas	CCGT old 1	5.13	3.5
Gas	CCGT old 2	4.79	4.18
Gas	CCGT new	*4.79*	*4.18*
Gas	OCGT old	*15.31*	-
Gas	OCGT new	*15.31*	-
Gas	present 1	15.31	-
Gas	present 2	*15.31*	-
Oil plants (all)		*15.31[1]*	-
Run of River and pondage		*0*	*0*
Reservoir		*0*	*0*
Pump Storage	Open Loop	*0*	*0*
Pump Storage	Closed Loop	*0*	*0*
Wind Onshore		*0*	*0*
Wind Offshore		*0*	*0*
Solar Photovoltaic		*0*	*0*