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FUTURE-PROOFING THE EUROPEAN POWER MARKET

REDISPATCH AND CONGESTION MANAGEMENT

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Contents

Abstract

In early 2024, the European Commission proposed a 90% emissions reduction target for the year 2040 in reference to the year 1990. Achieving this target largely relies on the deployment of distributed renewable generation. Currently the deployment of renewable capacity is mostly focusing on resource-rich areas with the highest capacity factors, not taking into account the grid topology. This can lead to a mismatch in the system, as those areas where renewable generation is focused do not necessarily align with where demand is located. The need to transmit the generated electricity *inside* a given zone could therefore regularly exceed the available grid capacity.

Our results suggest that this uncoordinated deployment will massively increase the need for redispatch – adjusting generator schedules after the market has cleared to achieve a physically feasible dispatch – as grids will be more and more constrained and incapable to fully transmit all available renewable electricity. In this way, up to 310 TWh of renewable generation could be curtailed due to limitations in the grid in 2040 in a business-as-usual grid expansion scenario, The need for redispatch could be further worsened by an inefficient operation and siting of electrolysers.

To address these issues at a time when renewable deployment is being scaled up substantially across the EU, we propose to introduce further incentives for system-friendly investment and operation. To this aim, existing out-of-the market mechanisms, such as auctions for energy infrastructure should be adjusted to incorporate a locational component. As the system will balance out only gradually over time, short-term price signals should be improved as well. By implementing bidding zone splits that reflect structural congestion at the border of a bidding zone, operational incentives can reflect better supply and demand available in the grid. It should further be assessed whether far-reaching alignment with the physical reality could be necessary to operate a climate-neutral power market. In this case, a more structural reform should be considered that substantially increases the spatial granularity of the wholesale market price signal at once.

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Executive summary

Policy context

In early 2024, the European Commission has proposed a climate target of 90% emissions reduction by 2040. The associated scenarios are relying heavily on the deployment of variable renewables, such as wind and solar PV. Deployment that focuses on resource-rich areas – where wind and solar potentials are strongest – increases the risk that transmission grid infrastructure could be insufficient to transport the energy to demand centres, which are often outside the main area of renewable deployment. This condition may lead to a state in which the wholesale market produces inefficient dispatch decisions that are not aligned with the physical reality in the grid.

The main instrument in the European legislation to address this issue is the Bidding Zone Review (BZR), which aims at redrawing bidding zone borders to take structural grid congestion into consideration at the border of each zone. The current BZR kicked off in 2019, with ACER proposing alternative bidding zone configurations in August 2022. Currently, European TSOs investigate the proposed configurations, with final results being expected in December 2024.

Key conclusions

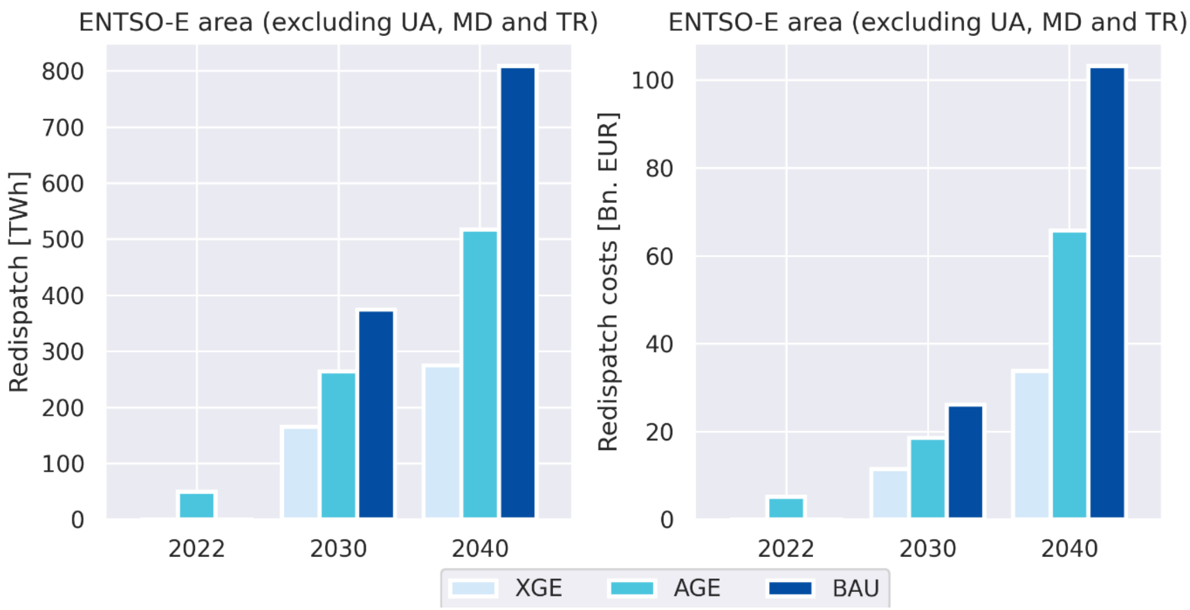
— **Redispatch volumes in *all* investigated grid-expansion scenarios increase massively in the time period until 2040. Even in the extreme grid expansion (XGE) scenario, which foresees expanding the total circuit length in Europe by more than a third, the total redispatch volume increases almost six fold.** While 2022 saw 50 TWh of redispatch in Europe, it could increase to 165 TWh in 2030 and 274 TWh in 2040 in the XGE scenario. In a business-as-usual (BAU) scenario – which foresees that grid expansion progresses only at historic rates – redispatch could even be as high as 374 TWh in 2030 and 809 TWh in 2040. The associated costs were calculated to be between 11 – 26 Bn. EUR in 2030 and 34 – 103 Bn. EUR in 2040, compared to 5 Bn. EUR that incurred for remedial actions in 2022.

— **Curtailment of renewable energy due to grid congestion in 2040 could be as high as 310 TWh in the BAU scenario. Hydrogen production was further identified as a redispatch driver across all investigated scenarios and target years.** For 2040, a conservative estimation yielded a redispatch increase of 78 TWh in the BAU scenario.

— **Several policy options exist to tackle these challenges by improving investment incentives as well as incentives for a better operation of the system.** Policy instruments that aim to mobilize investment – such as renewable auctions and capacity markets – can be improved by adding a locational component that reflects the state of the grid. Bidding zone splits that prove to improve the market outcome should be implemented, as they set better incentives for an efficient operation. We furthermore recommend to perform an analysis of the costs and benefits of locational marginal pricing at a high granularity in a climate-neutral power system.

— **It is vital that this issue is addressed as soon as possible to achieve a better balance of demand and supply inside the market zones of the European power system.** The period until 2040 is essential to manage where renewables and hydrogen generation are located. To achieve an efficient system, it appears necessary to improve incentives for investment *and* operational decisions.

Figure 1: Evolution of redispatch volumes and costs in the European power system.



Source: JRC analysis

This study

For this work, we have developed a European model that mirrors closely the interactions between power markets and grids. The base model features a resolution of 1024 nodes in the electricity network and is based on the open model *PyPSA-Eur*. We expanded on this system model, incorporating custom routines for grid expansion, flow-based market coupling and redispatch. These routines are essential to capture market dynamics and how these affect the physical system. The performance of these routines was assessed through a backtesting exercise that aimed to replicate the redispatch volumes of 2020, and which delivered good results.

The model further takes into consideration the future evolution of the system in line with the proposed 2040 climate target. This includes deployed renewable capacity, the projected evolution of demand, the penetration of flexible consumers, such as heat pumps and electric vehicles, and the amount of installed electrolysis capacity in the European system.

Main findings

In this study, we investigate three grid expansion scenarios for the target years 2030 and 2040, which differ in how much countries reinforce their national grids. They describe a business-as-usual (BAU) case, which extrapolates current grid expansion trends, an ambitious-grid-expansion (AGE) scenario, which assumes that the rate of reinforcement doubles, as well as an extreme-grid-expansion (XGE) scenario, where current grids are expanded by more than a third of their currently existing circuit length until 2040.

We find that the uncoordinated deployment of distributed renewable generation in line with the EU's climate targets will exacerbate existing congestion in the European electricity grid and create new bottlenecks. All scenarios result in a massive increase in redispatch needs. Redispatch describes the adjustments made to the dispatch *after* the market cleared, which become necessary to achieve a physically feasible dispatch. In 2040, two of the three scenarios foresee that European redispatch needs increase to the order of magnitude of the annual electricity consumption of countries like France and Germany. Where redispatch is organized through bilateral contracts, this amount could require massive efforts to bring forward the necessary remedial actions.

In systems that rely on a market-based approach, redispatch volumes could be even larger than assessed here, as redispatch markets offer opportunities for inc-dec gaming[1].

In this way, large amounts of renewable generation could end up being curtailed, due to grid congestion. Our assessment suggests that between 50 and 120 TWh of renewable generation is at risk of being curtailed in 2030 due to insufficient grid capacity, with 100 to 310 TWh being at risk in 2040.

We further observe that the operational incentives for hydrogen production are misaligned with system needs. In the BAU scenario, electrolysers exacerbate grid congestion, increasing redispatch by at least 78 TWh in 2040. This is a lower-end estimate, as it only considers increases in redispatch that occurred at the node where electrolysis was installed. In reality, redispatch triggered by hydrogen production could be even larger, also because our scenarios assume a correlation between installed renewable capacity and electrolyser deployment. This is currently not mirrored in the European legislation, which requires that green hydrogen production is only matched by renewable generation in the same bidding zone – and could well be on the wrong side of a bottleneck.

To address these challenges, we suggest to improve both operational and investment incentives. To achieve a better balance at the system level, it is necessary to steer better where renewable capacity and hydrogen generation is located. Whenever these projects receive financial support through an auction mechanism, this can be done by adding a locational component to the auction. Adding such a component to existing and planned capacity remuneration mechanisms may further prove important to maintain the feasibility of redispatch, as it ensures that capacity is available in the right places. In addition, grid charges can incentivize investment in the right locations if they include a locational component.

Further, the operational price signal can be improved by increasing the spatial resolution at which the European power markets are cleared. The BZR offers an opportunity to take structural congestion into consideration at the border of newly drawn zones. Further assessment is necessary whether increasing spatial granularity in an evolutionary manner, through bidding zone splits, is sufficient for a successful energy transition, or whether a transition towards an LMP system could become necessary.

Related and future JRC work

In 2020, the JRC published a qualitative assessment of the introduction of nodal pricing in the Internal Electricity Market (Antonopoulos et al., 2020). In the context of the European market design debate of 2022, the JRC has proposed an overhaul of renewable and capacity auctions to include locational information in the auctioning process (Thomaßen et al., 2023). The JRC is further providing scientific support to ACER on European assessments such as the Bidding Zone Review (BZR) and the European Resource Adequacy Assessment (ERAA), employing its power sector modelling capabilities and tools. Further work on this topic will include a quantification of the impact of locational renewable auctions, as well as the impact of smaller zonal configurations or even locational marginal pricing.

Quick guide

The study is structured as follows: Section 1 features a general introduction to the topic. In section 2, the methodology for the case study is presented. Section 3 outlines the results, while section 4 features the corresponding discussion. In section 5, potential policy instruments are discussed that could be suitable to address the issue, while section 6 concludes.

[1] Inc(rease)-dec(rease) gaming refers to exploiting arbitrage between two market sessions, where one session is cleared at a higher spatial resolution than the other, which can end up increasing congestion in the grid. For further information, we refer the reader to (Hirth et al., 2019), as well as section 5.2 of this report.

1 Introduction

In February 2024, the European Commission proposed a 90% emissions reduction target for 2040 (European Commission, 2024a). This would imply a far-reaching decarbonization of the power sector. According to the corresponding impact assessment, over 90% of electricity would then be generated by carbon-free electricity, with 81-87% of consumption being supplied by renewable technologies (European Commission, 2024a).

The lion's share of renewable capacity currently added to the grid consists of distributed renewable technologies, such as wind and solar (IEA, 2023a). If deployment focuses on areas further away from load centres, and where grids are weaker, it can create bottlenecks in the grid or exacerbate existing ones (Van Den Bergh et al., 2015). In Europe, this is a real threat, as renewable auctions do not sufficiently consider the local grid conditions. While many factors can play a role in which bids ultimately win the auction, reality shows that those areas with the best renewable potentials usually see the largest deployment, even if mechanisms exist to correct bids for the quality of the resource[2]. In addition, electricity is priced on a zonal level, which could – at least in large zones – be too coarse of a price signal to correct these trends[3]. In this way, continued uncoordinated renewable deployment could end up undermining the efficiency and functionality of European market zones and lead to the curtailment of large renewable energy volumes.

1.1 The European zonal market design

The Internal Electricity Market is structured into several market zones (**Figure 2**). These zones represent the level on which demand and supply are being matched, and on which the flows to other zones are being determined. Transfer capacity is taken into account at the border between two market zones, which implies that the transmission infrastructure inside a zone is not being considered during the market clearing process. Prices are determined at zonal level as well, and apply to all bids that were accepted inside the respective market zone.

In the European system, market zones often align with the geographical borders of the respective countries, though notable exceptions exist. In the Nordics, all countries but Finland consist of several market zones, with Denmark consisting of two, Sweden of four and Norway even of five zones. Similarly, Italy is split up into six market zones[4]. These zonal configurations can reflect a natural border – for example the sea – separating two parts of the country, such as East and West Denmark. In other cases – as in Sweden, Norway or on the Italian mainland – they reflect limited available grid capacity at the border of the respective zones. Designing zones to reflect structural congestion patterns can be considered as the blueprint for the EU's approach towards defining the borders of a bidding zone, as specified in the *Electricity Regulation*[5] Article 14:

> *[…] Bidding zone borders shall be based on long-term, structural congestions in the transmission network. […]*

The article goes on to state that bidding zones should contain structural congestion only temporarily, and that *remedial actions* to mitigate congestion should only be applied temporarily, not as a structural solution. Remedial actions describe measures being taken by the TSO to correct the market outcome with the ultimate objective of achieving a physically feasible dispatch. To this aim, the TSO can employ redispatch – correcting the market outcome by ordering downward and upward corrections of schedules – or countertrading, where TSOs buy energy offers in a different bidding zone to relieve bottlenecks in their own control area. In this study, we use *redispatch* as an umbrella term for both of these remedial actions.

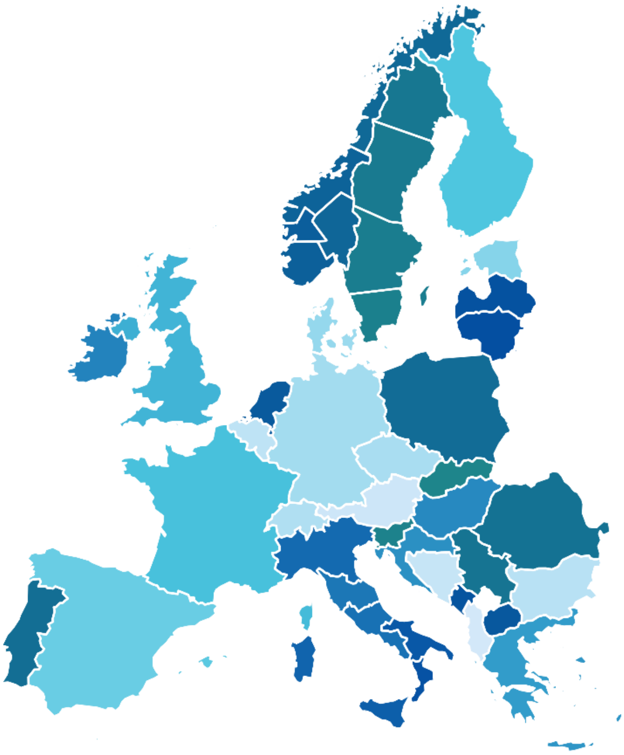
[2] Germany, for example, has introduced a mechanism that correct bids by normalizing them to a reference location (Bundesministerium für Wirtschaft und Klimaschutz, 2016). Nonetheless, most wind deployment focuses on the Northern and Eastern German regions (BWE, 2024).

[3] For example through market-based investments or remuneration mechanisms that factor in the local electricity price.

[4] In addition, there exist bidding zones that cover more than one country, such as the German-Luxembourgian zone, which historically included Austria as well.

[5] Regulation (EU) 2019/943

Figure 2: Zonal electricity markets in Europe.



Source: JRC based on (Electricity Maps, 2023)

1.2 Redispatch

As internal congestion is not considered in the market clearing, redispatch becomes a necessity if the exchanges taking place inside a zone exceed the available transmission capacity. As an example, such a situation can occur if wind capacity is primarily deployed in one resource-rich area, while industrial electricity demand is focused in a different area inside the same market zone. In hours with favourable wind conditions, the market clearing algorithm would produce a dispatch that implies large exchanges from wind generators to industrial consumers. If the resulting flows exceed the available grid capacity between the two, the system operator has to intervene – through redispatch – to correct the market outcome and achieve a feasible dispatch. In this situation, more costly generation on the other side of the bottleneck, closer to the industrial consumers, would be activated, while wind generation would be curtailed to align the market outcome with the physical reality.

To achieve a 90% emissions reduction by 2040, renewable deployment has to increase substantially across the EU. If deployment does not align with those areas where electricity demand is located, grid infrastructure is necessary to transmit the electricity to demand centres, creating an asymmetric system. This asymmetric deployment therefore increases the need for grid expansion – through reinforcements and newly built lines. If grid expansion does not keep pace, renewable deployment could create new or exacerbate existing bottlenecks inside the market zones, thereby leading to immense redispatch needs and ultimately to large volumes of renewable electricity being curtailed.

1.3 Objective of this study

This study aims to assess the implications of continuous asymmetric renewable deployment in line with the 90% emissions reduction target on the power sector, as well as the interaction with the current zonal market design in Europe. We assess to which degree this uncoordinated deployment creates new and exacerbates existing bottlenecks in the grid, and how this affects the amount of remedial actions necessary to maintain a stable grid operation. In this context, we assess to which degree flexible demand in zonal markets increases redispatch needs, and how bottlenecks affect the production of renewable electricity in Europe.

2 Model

In this case study, we use *PyPSA-Eur*, a model of the European power system (Hörsch et al., 2018), as the basis. It includes the transmission grid infrastructure based on the ENTSO-E Grid Map, local renewable generation timeseries generated with the help of weather data, as well as a georeferenced data set of conventional power plant capacities (Gotzens et al., 2019). This *base model* is extended by additional functionality, for example for grid expansion and flow-based market coupling (FBMC), which will be described in more detail in this section.

PyPSA-Eur relies on a couple of approximations, due to the fact that neither substation-specific demand curves are known, nor the grid connection point of each power plant. This is dealt with by assigning power plants to the nearest substation and distributing demand based on population and GDP. As recommended by the developers (Hörsch et al., 2018), we do not run the model at full resolution, but rather cluster it to 1024 nodes to improve the robustness of the results. This corresponds to 4-5 substations being clustered together on average, which is in the range that has been identified to deliver realistic grid results (Frysztacki and Brown, 2020). The code for the network produced by PyPSA-EUR is *elec_s_1024_None.nc,* which serves as the starting point, i.e. the base model for further modifications.

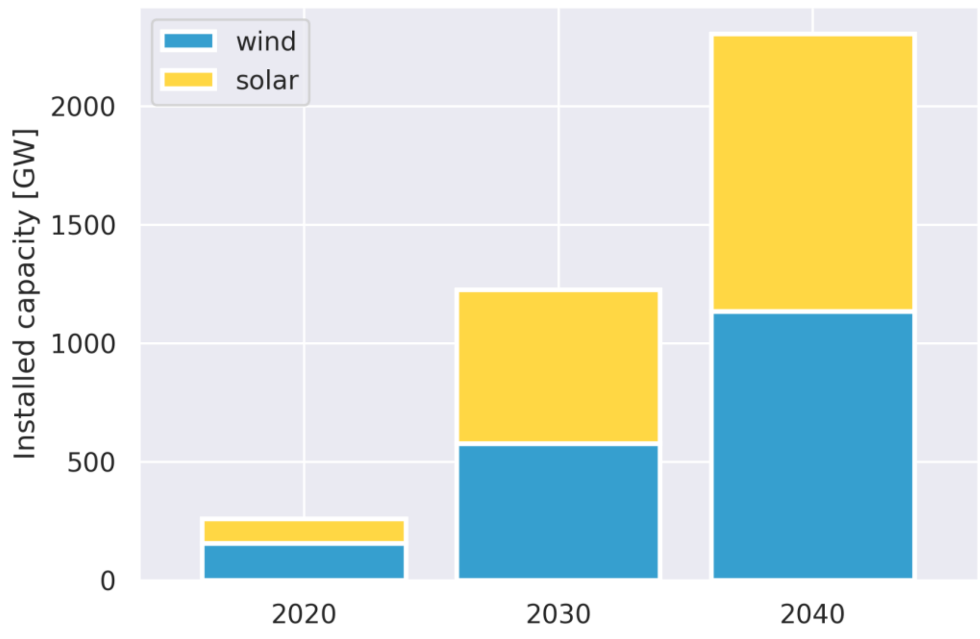
The following sections detail how the scenarios were built on top of the base model. The scenarios for 2030 and 2040 are based on country level data from a European scenario in line with the proposed 2040 target. All results presented in this study comply with the S3 Scenario of the Climate Target Plan 2040 with regard to total installed renewable and battery capacities, total electricity demand, as well as the split between heat pumps, electric vehicles and other purposes (European Commission, 2024b). In addition, the TYNDP 2022 (ENTSO-E and ENTSO-G, 2022), national scenarios and own estimations were used to complement the picture where necessary.

To acquire a complete grid model for the target years, it is necessary to distribute country level data on capacity additions and demand increases to locations inside the market zones. The following sections will describe the scenarios, as well as the methods and heuristics used to geographically allocate all system components – such as distributed renewables, storage and hydrogen production.

2.1 Variable renewables

The resulting scenario foresees more than a four-fold increase in variable renewable capacity until 2030, compared to 2020 levels (see **Figure 3**). Between 2030 and 2040, another doubling of capacity is foreseen.

Figure 3: Renewable capacities on European level used in the case study.



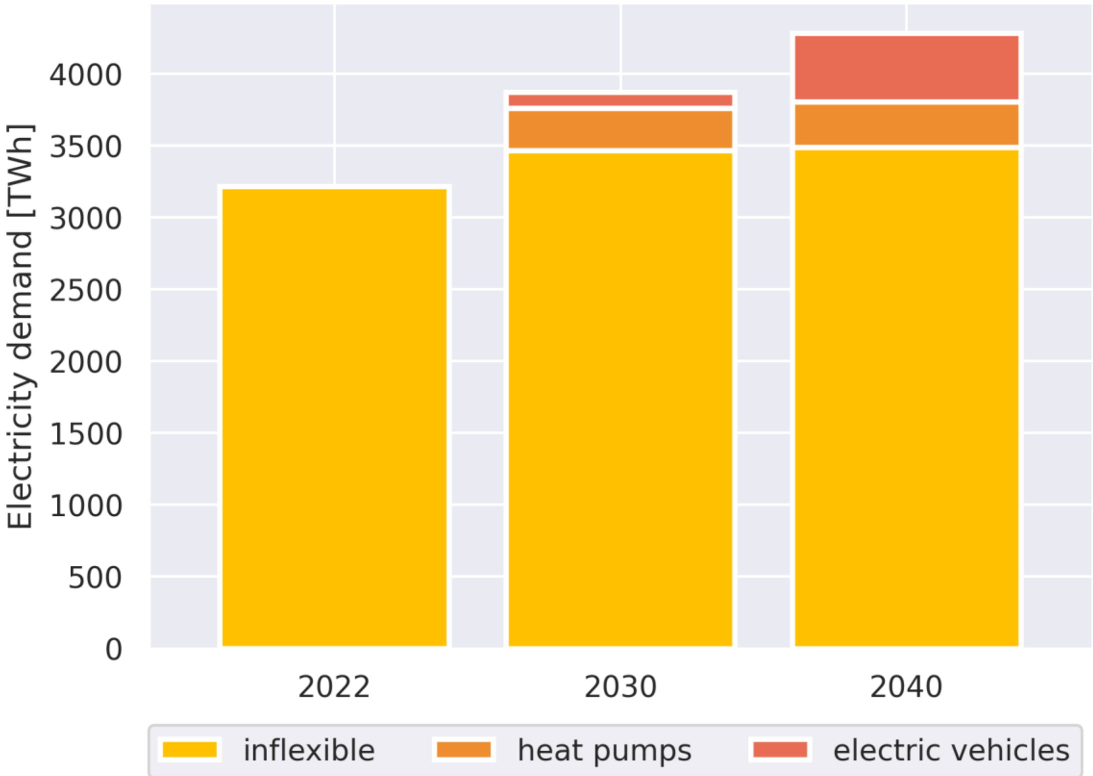
Source: JRC analysis

In the zonal case, distributed renewable technologies inside each country are allocated in proportion to total generation potential in each of the geographical zone within said country. Total generation potential is calculated based on the annual capacity factor, as well as the total installable capacity. This approach was found to produce realistic deployment patterns for a zonal market, as it allocates more capacity in areas with good wind or solar resources.

2.2 Demand

Electricity demand – excluding electricity used for hydrogen production[6] – is foreseen to increase to more than 3700 TWh in the European system by 2030, with another increase to more than 4200 TWh by 2040. From 2030 on, electricity demand from new consumers is playing an increasingly important role, with the share of heat pumps and electric vehicles constantly increasing.

Figure 4: Electricity demand (without demand for hydrogen production) in the 2030 and 2040 scenarios for the ENTSO-E area excluding Ukraine, Moldova and Turkey, compared to 2022 values.



Source: JRC analysis

PyPSA-Eur allocates electricity demand based on GDP and population. This approach was kept, and the demand curves were rescaled to match the annual consumption values from consumers excluding electric vehicles, heat pumps and electrolysers (which are the consumers we consider as flexible in this case study).

2.2.1 Demand flexibility

Electricity demands from heat pumps and electric vehicles (EVs) are modelled to maintain the characteristics of their flexibility by depicting the rationale of their operation as close as possible.

[6] Electricity consumption for hydrogen production is not treated as an input for this exercise, as the model will determine the amount of hydrogen production that takes place based on strike price and electrolysis capacity, compare section 2.2.1.

Heat pumps are modelled using the *load_profile_residential_heating_generic* from the HOTMAPS project as the daily profile for heating demand (Pezzutto et al., 2019). These heating demands were scaled using heating degree days provided by (De Felice and Kavvadias, 2019). Heat demand is then converted to electricity demand using the coefficient of performance for air-sourced heat pumps, based on (Staffell et al., 2012), calculated as:

$$COP = 6.81 - 0.121\,\Delta T + 0.00063\,\Delta T^2$$

We further assume that heat pump load can be shifted, with the help of thermal storage, which can be provided by dedicated thermal storage installations or by the mass of buildings (Thomaßen et al., 2021).

Similarly, the module to model the charging process of **electric vehicles** aims to depict the physical reality behind it. The basis is an EV activity profile based on highway activity data from the German Federal Highway Authority (Bundesamt für Straßenwesen, 2021).

Survey data from the German Ministry for Mobility and Digital Infrastructure suggests that the trip duration is less than one hour (Bundesministerium für Verkehr und digitale Infrastruktur, 2017). Due to a lack of data for other European countries, we assume that drivers across Europe have similar driving habits. Due to the short duration of the average trip, we assume that drivers reconnect their car to the charging station directly after each ride, i.e. in the same hour. As the average distance travelled is only 15 km per ride, we assume further that the battery can be recharged in the same hour. In reality, there might of course be an overlap with the next hour. This, however, affects the charging profiles only mildly. In addition, we model a degree of flexibility for EV charging, which renders these differences even less significant.

The degree of flexibility that the model has in recharging the batteries is then dependent on the residence time. If the residence time is one hour, charging is completely inflexible, as the batteries have to be refilled instantly after the ride. We do not assume any flows from batteries back to the grid, as vehicle to grid has not been demonstrated yet on a large scale. We further assume an average residence time of 2 hours for electric vehicles.

Lastly, **electrolysis** has been modelled as price sensitive demand. We selected a strike price of 50 EUR/MWh, which aligns with the range of hydrogen bids listed in (Ruhnau, 2022). Hydrogen production therefore only takes place when the market price drops below this level.

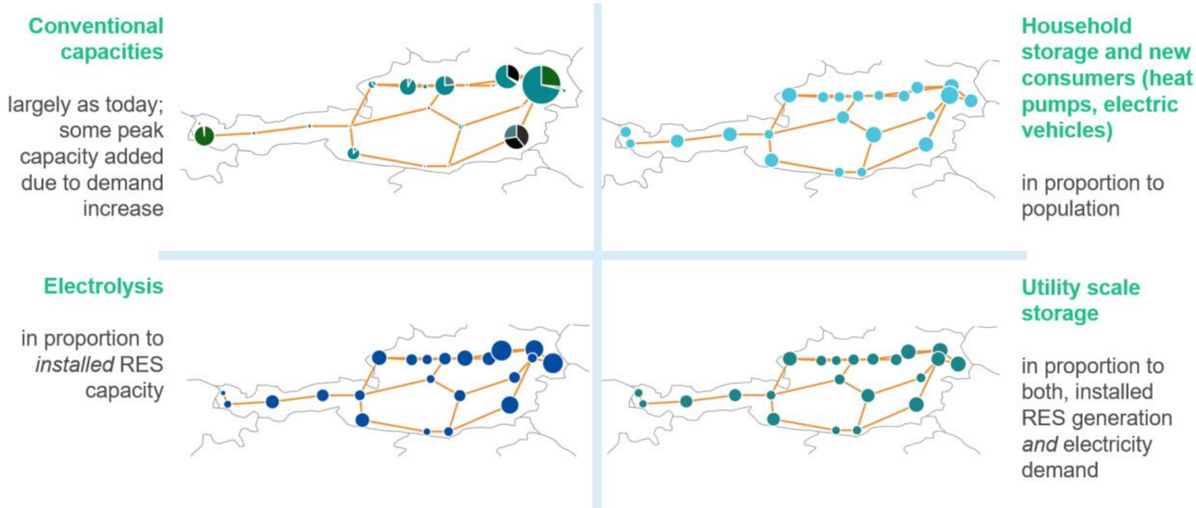
2.3 Storage and other flexibility

Dispatchable generation and large hydro installations are added in the initial building phase of the model. Due to policy uncertainty in the wake of the European gas crisis of 2022, we maintained today's generation park, and added some additional peak load generation fuelled with gas, as this was necessary to avoid load shedding due to the increase in electricity demand (compare section 2.2). This appears to be appropriate for this case study, as we assume that new power plants will be built in locations where power plants were previously decommissioned, since the grid connection of the previous plant can be used. The main divergence could therefore be the marginal cost present in the location in question. Both hydrogen – as a carbon neutral alternative – and fossil-fuelled generators will have high marginal costs – due to carbon pricing in the latter case. It is therefore likely that dispatch patterns would change little if fossil power plants were replaced by hydrogen-fuelled generation.

Batteries were separated into utility scale storage and household storage by applying the split between the two technologies from the TYNDP 2022. Household batteries were distributed in proportion to demand. Utility scale storage, on the other hand, was distributed based on total demand and total renewable generation from installed capacities. This follows the assumption that utility scale storage will be used on the one hand to increase the market value of renewables, for example as on site storage near a solar park. On the other hand, we assume that large industrial consumers will build batteries to optimize their electricity bill.

Figure 5 gives an overview how flexible system components – including flexible demand described in section 2.2.1 – are located.

Figure 5: Distribution of flexible system components (exemplary depiction).



Source: JRC analysis

2.4 Flow-based market coupling

It is assumed for all zonal markets that the exchanges are managed through flow-based market coupling (FBMC). FBMC currently already applies to all market zones of the Core region, and is set for implementation in Scandinavia in the end of 2024, therefore covering the majority of the continent with regard to market zones and aggregated demand. The extension to the other areas follows practical considerations. First of all, an additional extension to the Iberian peninsula, the Baltics or the Balkans appears likely, given the past extensions to Core and Scandinavia. Since we model interconnector expansion, as well as different rates of grid expansion inside each zone, FBMC furthermore ensures that the allowed exchanges are consistent with the underlying grid model. Taking NTC values from a third study instead would risk that these NTC values were based on a different grid that does not align with the one we model. This could create inconsistencies that can impact the results.

The modelling approach for FBMC follows the methodology presented by (Byers and Hug, 2020), which is generally in line with FBMC implementations used by ENTSO-E or Elia (Elia, 2023; ENTSO-E, 2023). We use a nodal base case, where the model is run at full 1024 node resolution, as this approach resulted in the lowest redispatch requirements (Byers and Hug, 2020), as well as generator shift keys (GSKs) which are determined by the installed firm capacity on each node in relationship to the total inside the respective zone. To avoid solving the entire nodal model, we further cluster all hours of the year based on total variable renewable generation and total load. For this, the total sample of 8760 hours is split according to whether the hour is on a weekday or the weekend, at night or during the day[7], as well as in the winter or the summer half of the year[8].

For each of these eight groups, a dendrogram of the sample's distances was created to determine a suitable number of clusters, selecting 2-3 clusters for each group, depending on the distribution of distances. Afterwards, k-medoids clustering was performed to determine the clusters, as well as their centres, which are interpreted as the representative hour for each cluster. For each representative hour, a nodal dispatch simulation is then performed to determine the dispatch in the base case and the associated flows.

The initial line loading is determined with the help of the nodal base case by setting the zonal net positions to zero. We use GSKs, which represent each node's share of firm capacity, in reference to the firm capacity of the entire zone (Elia, 2023) and a flow-reliability margin (FRM) of 10%. We further apply a minimum remaining available margin (minRAM) of 70% in all scenarios, to comply with the 70% criterion, while 20% minRAM has been used inside Core for the validation of the model.

[7] Hours between 08:00 and 20:00 are categorized as daytime, while the remaining hours are categorized as night.

[8] October to March is categorized as the winter half, and April to September as summer half.

2.5 Grid expansion

We model grid expansion as a two-step process:

1. Expansion of cross-border capacities
2. Country-level grid expansion.

The practical purpose behind this sequence is that we end up with the same cross-border capacities even with different rates of grid expansion inside the country. This would not be the case if cross-zonal (CZ) capacities and country-level grids would be simultaneously expanded, as it would imply a coordinated process. Further, it replicates the policy process, as cross-border lines are planned in a coordinated way in the TYNDP, while country level grid planning usually follows, taking into account the results of the TYNDP (see (50Hertz et al., 2023)).

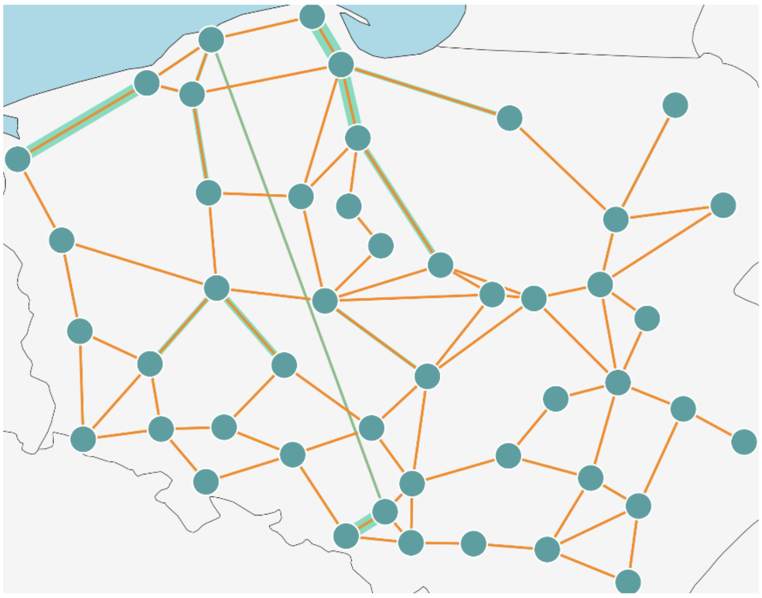
In a first step, we thus expand cross-border lines between the countries. The economic needs identified in ENTSO-E's TYNPD serve as the basis. As they describe NTC additions in comparison to 2025, we use interconnector capacities described in ERAA 2022 as the baseline. Based on these values, we run an optimization to increase CZ capacity according to the ratio between the capacity in the target year on that border, as well as the respective capacity in 2025. This approach is an approximation, as we only know the NTC values, but not the physical capacity that is added to the system in a certain location.

In a second step, we allow the model to increase grid capacities inside the countries. Here, the model can increase the capacity on all available AC and DC lines until the entire grid inside the country is expanded by a ratio γ:

$$\gamma = \frac{\sum_i l_i^{AC} \bar{F}_i^{AC,exp} + \sum_i l_i^{DC} \bar{F}_i^{DC,exp}}{\sum_i l_i^{AC} \bar{F}_i^{AC,0} + \sum_i l_i^{DC} \bar{F}_i^{DC,0}}$$

With $l_i^{AC/DC}$ being the expanded and the length of AC and DC lines, $\bar{F}_i^{AC/DC,0}$ being the initial and $\bar{F}_i^{AC/DC,exp}$ the expanded capacity of these lines. The result of country-level grid expansion is shown exemplarily for the case of Poland in **Figure 6**:

Figure 6: Exemplary country-level grid expansion for Poland. Green bars indicate an increase in line capacity compared to the initial grid.



Source: JRC analysis

2.5.1 New grid projects

All TYNDP projects accounted for in the PyPSA-Eur workflow were added to the network. To account for potential newly-built HVDC lines inside a country, we added candidate expansion projects to the grid, without initial capacity. The model can and will expand these lines, giving them an actual capacity, wherever they are beneficial to the system. New HVDC candidates were added in Germany, Poland and France. In Poland and Germany, all new HVDC links listed in the grid development plans were selected. In France, where the latest grid development plan lacks precise information on new HVDC links, candidate projects were added between nodes with large opposing redispatch balances. Annex 1 gives an overview of all candidate projects.

2.5.2 Scenarios for inner-zonal grid expansion

In this case study, we investigate three different scenario, which differ with regard to the amount that the grids inside the countries are expanded. Two of these scenarios are inspired by German grid expansion figures – actual historical expansion as well as planned expansion according to the latest national network development plan (NDP). This is due to the fact that (1) we are not aware of any other Member State data on network development in the last decade and (2) the German NDP is the only one known to the authors which considers the needs associated with the climate neutrality target when planning the future network (50Hertz et al., 2023).

According to the German Ministry of Economics, it is planned to expand the innerzonal network by 11 749 km with a total length of the German network of around 37 000 km, which amounts to roughly 31.8% expansion in 2038, which is the target year of the plan (Bundesministerium für Wirtschaft und Klimaschutz, 2024). Based on this, we selected a grid expansion of 35% until 2040 inside each country on top of the projects listed in the TYNDP for the extreme grid expansion scenario (XGE). According to the official monitoring reports of the German energy transition, the grid was expanded by 2 245 km in the ten years from 2013 to 2022 (Bundesnetzagentur, 2023, 2014). If extrapolated until 2040, this amounts to an expansion of 9.6% compared to the current grid. The business-as-usual scenario therefore assumes only an additional national grid expansion by 10% in each country.

Box 1: Description of grid expansion scenarios.

In the **Business As Usual (BAU)** scenario, network expansion is following the historical trend observed in Germany in the years from 2013 to 2022. In 2040, the entire grid in each country is therefore expanded by **10%**.

The **Ambitious Grid Expansion (AGE)** scenario describes a world in which grid expansion is massively sped up compared to the historical trend, yet not to the levels foreseen in the German NDP. It can be seen as a middle-of-the-road scenario. As a result, the grids inside each country are expanded by **20%**.

The **Extreme Grid Expansion (XGE)** describes a scenario largely in line with the German NDP, based on which the grids inside each country are expanded by **35%**.

2.6 Redispatch

After the zonal market clearing, the production schedules of generators might not be feasible from a grid perspective. In these cases, remedial actions are necessary to achieve a feasible dispatch, reducing generation from some generators, while increasing generation from others. We use a redispatch approach that minimizes the redispatch volume. This mirrors the current practice, as it assumes that TSOs will aim to resolve any congestion issues with as little intervention as possible (Poplavskaya et al., 2020). The approach stands in contrast to welfare-maximizing redispatch, which might realize further trades, for as long as they increase the welfare of the system.

The objective minimizes the necessary redispatch to achieve a feasible outcome:

$$\min\left(G_g^{up} - G_g^{down}\right)$$

With the corrections G_g^{up} and G_g^{down} that describe a generator's deviation from the spot market outcome, i.e. positive and negative redispatch. Note that G_g^{down} describes a negative energy contribution, and therefore the sign in the objective is negative. We further mandate that only a certain share of redispatch can be resolved through CZ cooperation. This share x_{CZ}, describes the amount by which the balance of G_g^{up} and G_g^{down} is allowed to deviate on the level of an individual zone:

$$\sum_{g \in z} G_g^{up} \geq - \sum_{g \in z} \left(G_g^{down}\right) \cdot (1 - x_{CZ})$$

$$\sum_{g \in z} G_g^{up} \leq - \sum_{g \in z} \left(G_g^{down}\right) \cdot (1 + x_{CZ})$$

Roughly 15% of congestion management costs in the European system were attributed to countertrading in 2022, where TSOs buy energy – primarily in a different bidding zone – to resolve a bottleneck (ACER, 2023). In addition, bilateral agreements can be used for CZ redispatch. To account for potential agreements, and allow for the possibility that cooperation further increases in the future, we thus assume that 30% of redispatch can be optimized across bidding-zone borders. The impact of this assumption is checked with the help of a sensitivity analysis for how higher and lower shares of CZ redispatch affect redispatch volumes.

The degree to which each generator can provide up- and downward redispatch is further limited by the dispatch determined in the spot market. Since we clustered power plants to one entity, we use a linear approach to limit the degree to which they can provide redispatch.

$$G_g^{up} \leq \min\left(P_g^{nom}, \frac{G_g^{spot}}{ML_g}\right) - G_g^{spot}$$

With the nominal capacity P_g^{nom}, the scheduled generation G_g^{spot} determined by the spot market, as well as the minimum load factor ML_g. We developed this approach, since we do not know to which degree individual power plants are dispatched inside each cluster at each node. If each power plant inside the cluster is dispatched, the generation must be equal or larger than $ML_g \cdot P_g^{nom}$. In this case, the entire free capacity can be used for upward redispatch. If the generation is below this value, we derate the available capacity accordingly, calculated through the term $\frac{G_g^{spot}}{ML_g}$.

Similarly, we calculate the capacity available for downward redispatch:

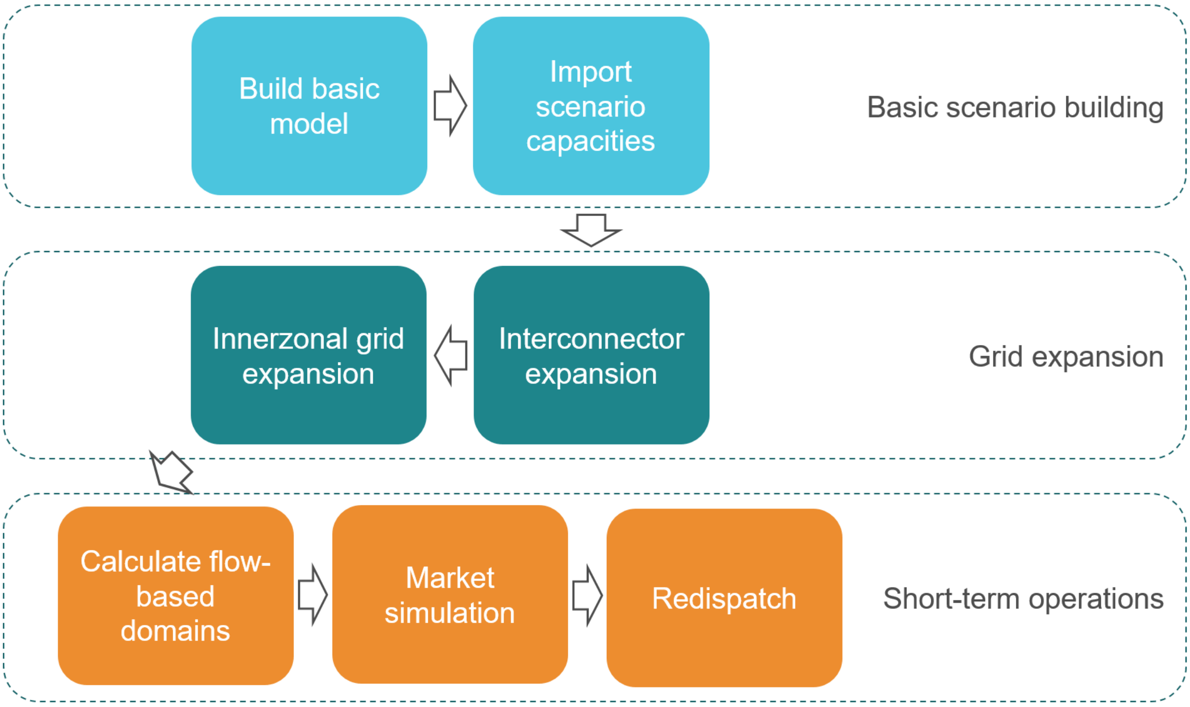
$$G_g^{down} \geq G_g^{spot} - \min\left(P_g^{nom}, \frac{G_g^{spot}}{ML_g}\right) \cdot ML_g$$

All generation technologies are available to provide redispatch, both up- and downwards, if they have available capacity in the given direction. Furthermore, hydro storage plants can participate in redispatch. We assume that their bid reflects the water value, which is reflected by the shadow price of the storage energy balance.

2.7 Workflow

The schematic workflow can be seen in **Figure 7**. At first, the base model is built with the PyPSA-Eur workflow. Then, we construct the respective scenario by adding capacities and demands. Afterwards, both grid expansion steps are executed, first expanding the cross-border capacities, and then the grids inside each country. The flow-based domains are determined in the next step, before running the market simulation. Finally, after the market outcome has been determined, the model calculates redispatch.

Figure 7: Schematic workflow.



Source: JRC analysis

2.8 Limitations to the approach

Since we optimize redispatch simultaneously, and allow for 30% of CZ cooperation, we cannot clearly differentiate which redispatch activation is due to a bottleneck inside the same zone, and where it was due to relieve a bottleneck in a different zone. Further, the modelled approach implies a high degree of cooperation between TSOs, as the model always finds the optimal solution (within the bounds that were set with regard to CZ cooperation). This might be an optimistic assumption, given that CZ redispatch relies on bilateral agreements or countertrading. In these situations, it is hardly a given that the optimal option to resolve a bottleneck is chosen.

In addition, the cost minimization approach depicts a perfectly competitive market setting in which no market power is exercised. We therefore do not account for bidding strategies that are employed by market participants to maximize their revenue, such as capacity withholding or adding a mark up to one's marginal cost. The redispatch outcome we calculate therefore represents a cost-based redispatch mechanism, and cannot account for strategic behaviour, such as *inc-dec gaming*, which can occur in market-based redispatch settings (Hirth et al., 2019).

3 Results

This section features the results of the case study. We start with the validation of the model, which was performed for the year 2020. In the subsequent section, the scenario results for the years 2030 and 2040 are presented.

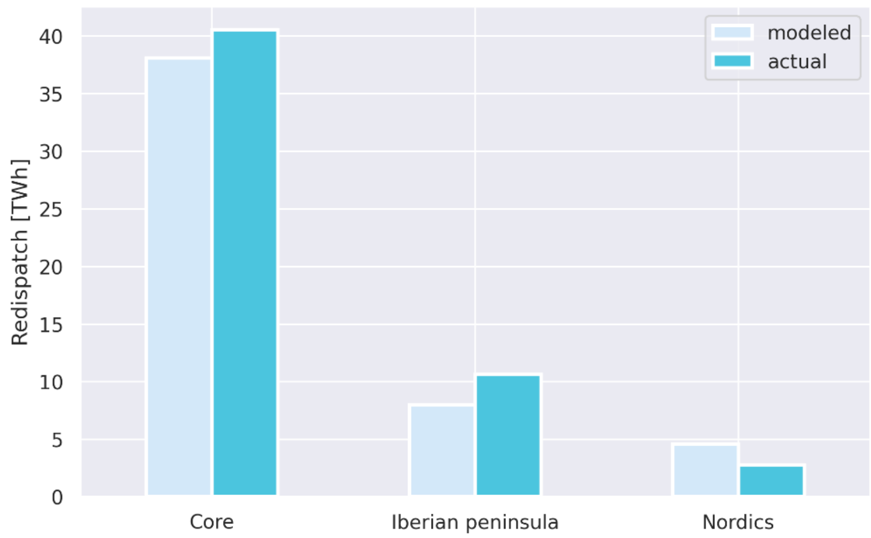
3.1 Validation

We performed a validation of the model, to ensure that it is sufficiently capable of capturing redispatch trends in the European system. The validation relies on redispatch data from ACER's Market Monitoring Report 2020 (ACER, 2022).

We used a model of the 2020 system built with the PyPSA-Eur workflow as the base model. The same modelling routines were applied as described in section 2, with the exception that routines for data import and grid expansion were omitted. FBMC was applied only in the Penta region. For all other borders, NTCs were used. Where available, we took NTCs reported from the ENTSO-E transparency platform. Data gaps were filled with ERAA 2022 data, with the exception of Norway, where the ERAA data set only features three Norwegian zones instead of five. To fill the gap, we calculated the average ratio between the total installed transmission capacity and the NTC on all borders. This ratio was then applied to the installed transmission capacity on the borders of Norwegian zones to estimate the missing NTCs. We furthermore allowed for 10% cross-zonal redispatch or countertrading, and applied a MACZT of 20% inside Core.

The results for three regions can be seen in **Figure 8**. We present regional results, since the redispatch approach can result in spill-overs, where bottlenecks inside one country are resolved by symmetric redispatch actions in a different country (compare section 2.7). Nonetheless, we can conclude that the modelled redispatch values align well with the actual values listed in (ACER, 2022). Reasons for the remaining deviations can be the lack of NTC data on some borders, the grid model, which relies on assumptions for the technical parameters of the lines, or inaccuracies in the location of renewable plants, as not all locations of renewable installations are known. Overall, the model accuracy appears well suited to assess future redispatch trends.

Figure 8: Validation results for the year 2020. Actual values taken from ACER Market Monitoring 2020 (ACER, 2022).

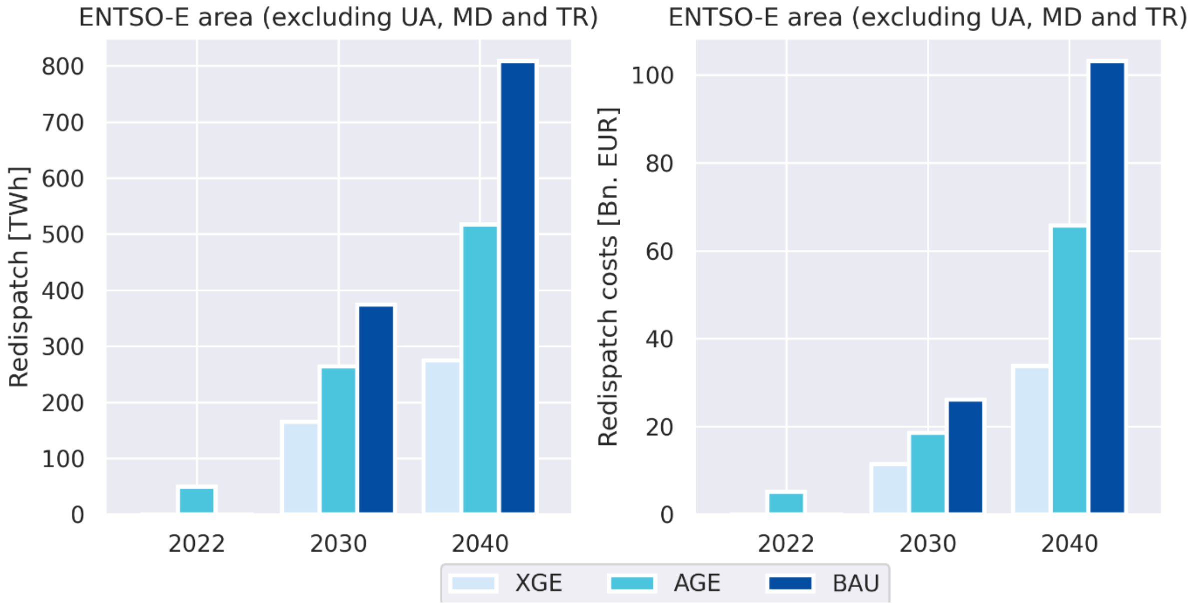


Source: JRC analysis, (ACER, 2022)

3.2 Redispatch volumes in the scenarios

All scenarios resulted in a substantial increase in redispatch requirements. While the observed redispatch volume in 2022 was 50 TWh, the European annual total increases to 165 – 374 TWh by 2030, depending on the level of grid expansion assumed in the respective scenario. This corresponds to 11 – 26 Bn. EUR. For the target year 2040, our scenarios even resulted in volumes between 274 and 809 TWh. The corresponding redispatch costs could be as high as 34 – 103 Bn. EUR.

Figure 9: Evolution of redispatch volumes and costs in the European power system.



Source: JRC analysis

Compared to the amount of renewables added to the system[9], we can observe a disproportional increase in redispatch, most notably in the low-expansion BAU scenario. The amount of redispatch caused by a marginal increase in asymmetric renewable deployment is therefore progressive, i.e. increasing with higher shares of renewables.

This observation is reasonable when considering that the first unit of renewable capacity added to the system usually does not cause any redispatch. If capacity additions in an asymmetric manner continue – focussing primarily on one region inside a given market zone – the point will be reached when transmission capacity to other regions will be insufficient to transport all generation during some hours with very high renewable production. In these cases, some renewable generation needs to be curtailed, and upward redispatch on the other side of the bottleneck has to be activated to make up for the missing generation. At some point – assuming that asymmetric deployment continues – saturation of the grid will be reached as well during lower hourly capacity factors of the renewable generation fleet. Therefore more and more of the potential renewable generation gets curtailed and results in additional redispatch.

One can imagine an extreme scenario, in which the grid in a certain area is fully saturated with renewable generation of a certain type. In this case, one additional MWh of renewable generation added to the grid in this area would result in one MWh of renewable energy being curtailed. We can thus derive the maximum marginal increase in redispatch per MWh of renewable energy added to the grid: A MWh that could not be integrated – even though it was traded in the market – would result in 2 MWh of additional redispatch. One downward (provided by the respective renewable plant), and one upward on the other side of the bottleneck, to compensate the lack of energy that would arise.

Redispatch costs rise disproportionally between 2030 and 2040, compared to the volume increase in redispatch, since dispatchable generation is more costly in 2040, due to the higher CO_2 price. These costs would likely not change substantially if redispatch was provided by hydrogen instead of fossil generators, as hydrogen costs are expected to be higher than the fuel costs of fossil generators today (IEA, 2023b).

A regional breakdown for registered costs and volumes can be seen in **Figure 10** and **Figure 11**[10]. The highest share of redispatch occurs in the Core region, which can be explained by it being the largest region and having the highest degree of interconnection. Here, redispatch in 2040 could be between 172 and 468

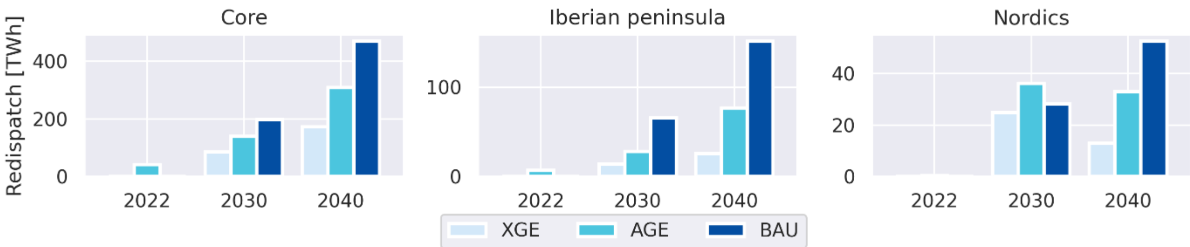
[9] As described in section 2.1 the scenarios assume that variable renewable capacity in the European system roughly quadruples by 2030 compared to 2020. Between 2030 and 2040, another doubling in capacity is foreseen.

[10] We focus on three regions where the issue appears to be most prominent, compare **Figure 12**.

TWh, 4-11 times higher than in 2022. The costs, estimated at between 5 and 13 Bn. EUR in 2030, can still be considered a conservative estimate, given that (Vom Scheidt et al., 2022) foresee redispatch costs of 4.9 – 7.2 Bn. EUR in Germany alone for the same target year. Similarly, the redispatch needs on the Iberian peninsula are rising across all three scenarios. While the increase in the XGE scenario could appear manageable, we see disproportionate increases in the BAU scenario in 2030 and in the BAU and AGE scenarios in 2040. This could indicate that the grid reaches saturation in more and more areas inside the region.

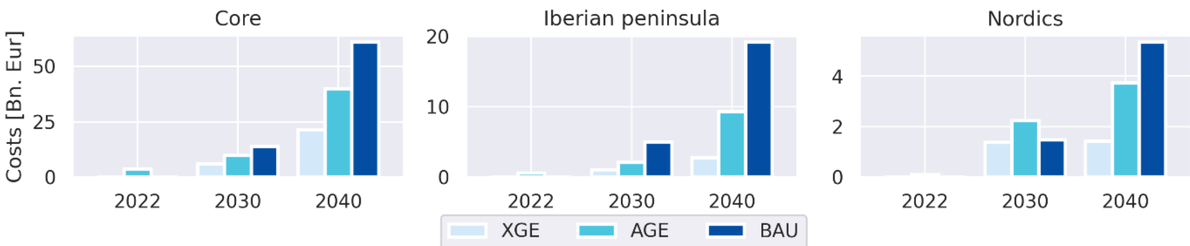
In the Nordics, we can further observe a counterintuitive result, as redispatch in the BAU scenario is lower than in the AGE scenario for the year 2030. This can be explained by Nordic regions providing redispatch services to the Core region. Even though a strong increase until 2030 is foreseen here, it appears as though ambitious grid expansion measures could stabilize redispatch needs during the 2030s.

Figure 10: Redispatch volumes in the different European regions.



Source: JRC analysis

Figure 11: Redispatch costs in the European power system differentiated by region

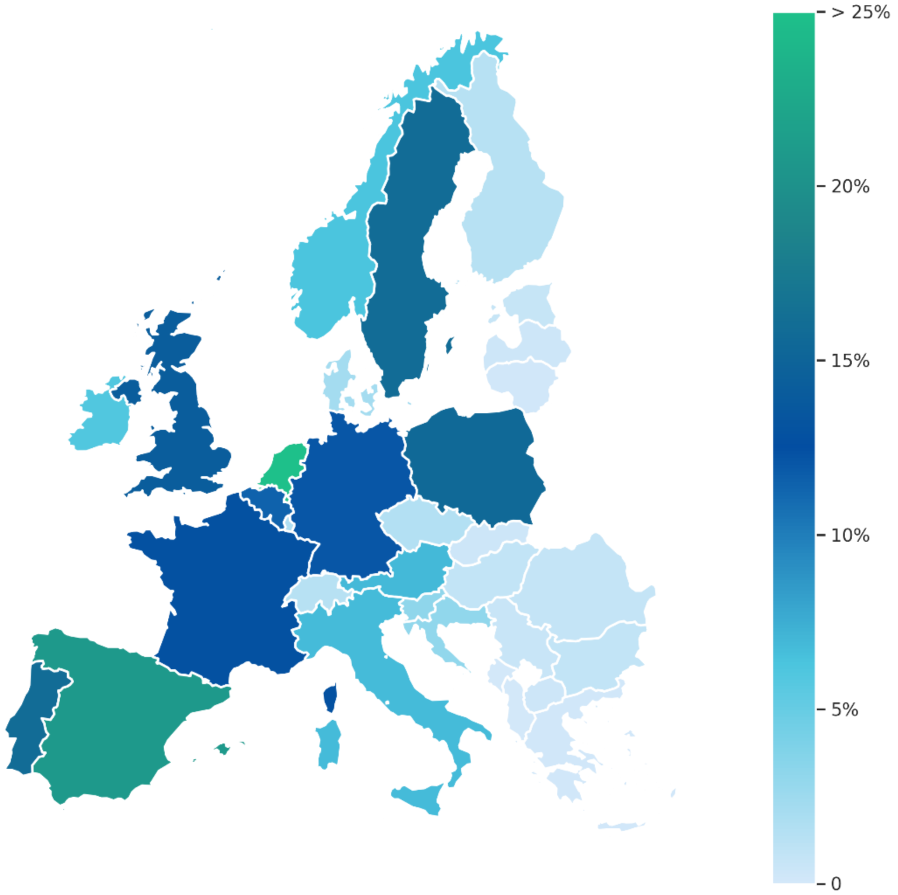


Source: JRC analysis

For the year 2040, redispatch volumes in the AGE scenario can be seen in **Figure 12** normalized to total demand. It has to be noted that the volume of redispatch attributed to one country does not automatically indicate redispatch needs in this country, but that it can also refer to measures that were taken to resolve a bottleneck inside a different country. Generally, a trend can be observed that smaller zones have smaller redispatch volumes normalized to annual demand, though notable exceptions exist. In the Netherlands, for example, the high share of redispatch could be explained by large offshore wind capacity in the North Sea, and insufficient transmission capacity to transmit this energy further south. The flows in Benelux countries are furthermore impacted substantially by larger neighbouring countries.

In the AGE scenario, redispatch related trade on a European level is roughly 12% compared to total demand. In systems with cost-based redispatch, these shares imply a very large volume of orders which have to be organized in parallel to the market. In systems where market-based redispatch is already the norm, redispatch volumes could increase further due to inc-dec gaming (Hirth et al., 2019), a gaming approach to maximize revenue through arbitrage between two market sessions with a different spatial granularity (see section 5.2 for further elaboration).

Figure 12: Redispatch volumes in the AGE scenario, normalized to total electricity demand. Year is 2040.



Source: JRC analysis

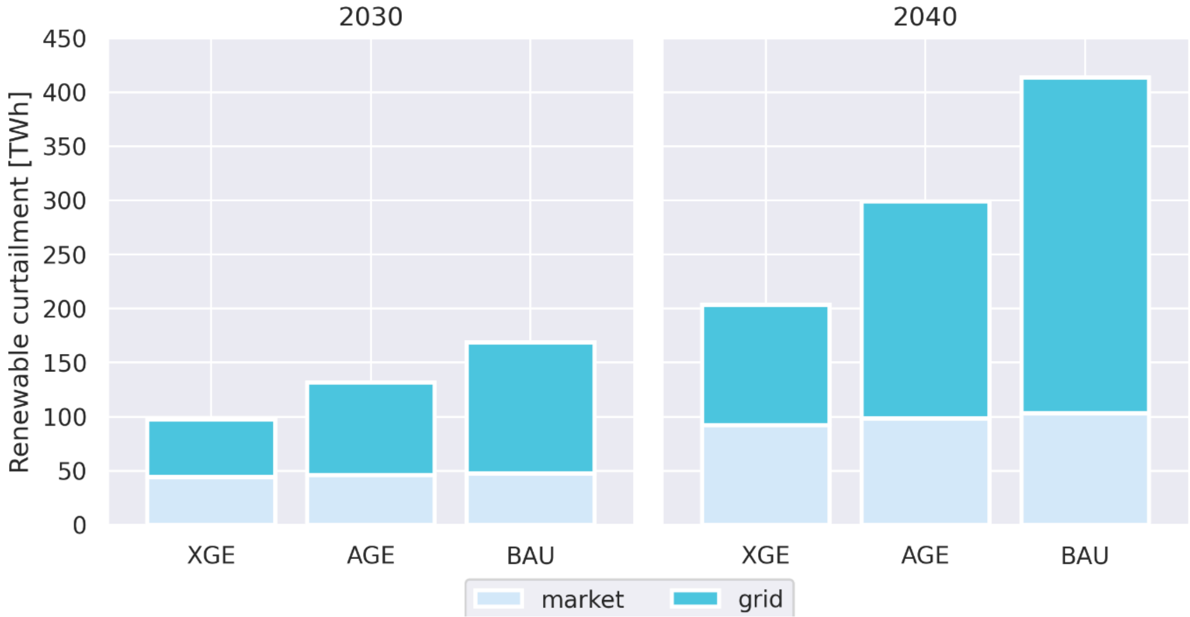
3.2.1 Impact on renewable generation

The need for redispatch results in additional renewable curtailment, as can be seen in **Figure 13**. Here, we differentiate between market-based renewable curtailment, i.e. renewable surpluses that could not be sold in the market as there simply was no additional demand for it, and grid-based curtailment. The latter describes renewable electricity that was sold in the market, but had to be curtailed as it could not be delivered through the grid. In these cases, renewable plants provided downward redispatch which has to be compensated by upward redispatch in a different location to maintain the grid's balance.

We observe that substantial amounts of renewable generation are curtailed due to bottlenecks in the grid. In the XGE scenarios, market-based curtailment and grid-based curtailment are more or less equal in both target years, with roughly 50 TWh each in 2030 and 100 TWh each in 2040. With less grid expansion, the ratio between grid- and market-based curtailment increases, and could be as high as 3:1, producing grid-based curtailment of up to 121 TWh in 2030 and 310 TWh in 2040. In the AGE case, where we assume that grid expansion doubles compared to current trends, 200 TWh of renewable electricity could end up being curtailed in 2040.

This shows the relevance of grid expansion measures to ensure that renewable generation is actually used, and not wasted due to insufficient grid capacity. It could further indicate that renewable generation should move closer to demand, as to minimize the grid infrastructure necessary for transmission.

Figure 13: Curtailment of variable renewable generation. Differentiated based on whether curtiailment occured in the market, or due to grid congestion.



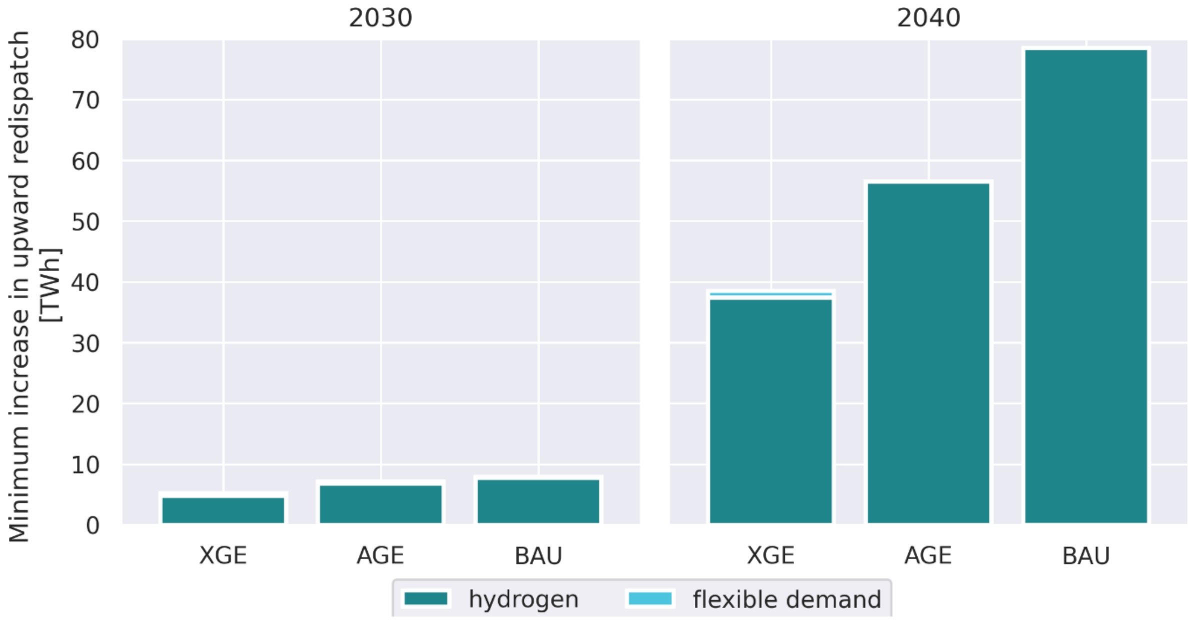
Source: JRC anaylsis.

3.2.2 Demand side flexibility and hydrogen production as redispatch drivers

To evaluate the degree to which flexible consumption – from heat pumps, electric vehicles or for the production of hydrogen – exacerbate congestion in the grid, we estimate the minimum redispatch caused by these. To this aim, we determine those hours to which load was shifted and during which hydrogen production took place. In a second step, we evaluate whether and how much upward redispatch was activated in the same location. The smaller value of the activated redispatch and the increase in flexible consumption is then interpreted as the minimum additional redispatch caused by the action. In the case of consumer flexibility that relies on *shifting* load – as the case for heat pumps and electric vehicles – we further assess whether upward redispatch occurred in the same location, when the load was reduced. If so, the reduction is subtracted, as redispatch was avoided by the load reduction.

This must be interpreted as the lower bound of redispatch triggered, as we cannot assess whether an action produced an activation of upward redispatch in neighbouring nodes with this approach. The results can be seen in **Figure 14**. The impact of flexible demand appears to be small, even negative in the BAU scenario in 2040, indicating that flexible demand reduced redispatch slightly in this case. Hydrogen production, on the other hand, could be a substantial issue, increasing bottlenecks in the grid, contributing at least 2-3% of total redispatch in 2030 and 10-14% in 2040. As we only calculated the amount of redispatch that can unequivocally be attributed, the actual value is likely even higher.

Figure 14: Lower bound of the Increase in redispatch due to flexible demand, differentiated by source.



Source: JRC analysis

This is remarkable, as we already assumed that hydrogen production would be correlated with installed renewable capacity (compare section 2.3), while Regulation 2023/1184 requires only placement inside the same bidding zone to fulfil the geographical matching criterion. Electrolysers could therefore well be placed on the wrong side of a bottleneck inside the same bidding zone and therefore exacerbate congestion *even further* than assessed here. Considering that industry is often placed in different areas than where renewable production is focused, there could well be an incentive to place electrolysis close to industrial end uses, as to minimize hydrogen transportation costs: (Vom Scheidt et al., 2022) assessed that electrolysis could increase redispatch costs in Germany by up to 17% already in 2030. Our estimate of how hydrogen affects redispatch needs therefore appears to be quite on the conservative side.

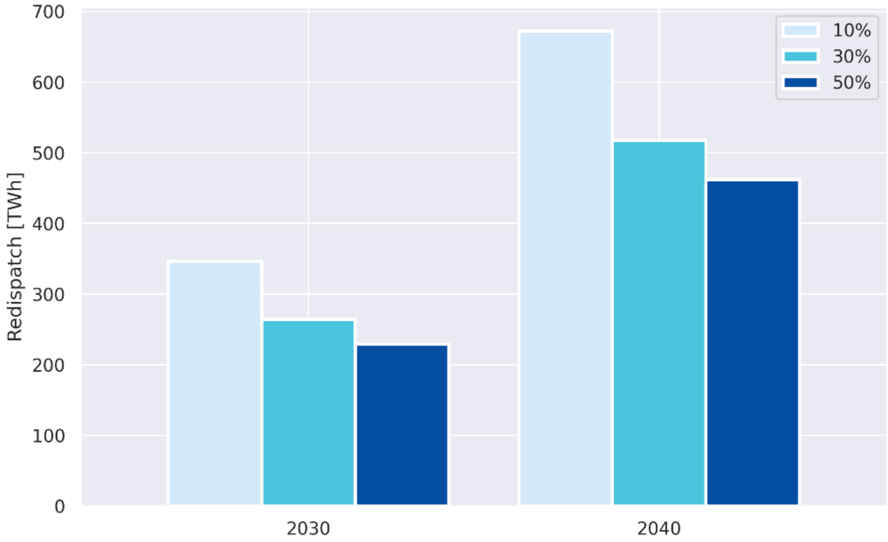
These results indicate a false alignment of incentives. The situation could likely be improved by steering electrolyser capacity to those locations where large renewable surpluses are expected, which has been deemed beneficial to the system by previous research (European Commission and Tractebel Engie Impact., 2024; Neumann et al., 2023). Further investigation is needed to assess whether the operational incentives also need to be aligned better with the physical reality in the grid. In this case, the spatial granularity of the wholesale-market price signal would likely need to increase to send the right operational signals.

3.2.3 Impact of cross-border cooperation in redispatch

The analysis presented in the previous sections assumes that 30% of redispatch can be resolved across zonal borders. This assumption shall be checked here, to see how it affects redispatch volumes if a higher or a lower share is assumed. It has to be noted that the model will calculate the optimal CZ redispatch. The outcome of this sensitivity analysis therefore describes a world with perfect coordination between all TSOs, something that cannot necessarily be assumed with the current bilateral redispatch agreements.

The results can be seen in **Figure 15** for the AGE scenario. A higher share of CZ redispatch therefore reduces the total aggregated redispatch volume, while reducing the share would lead to further increases. The effect is, however, disproportional: Reducing CZ redispatch to 10% would increase the total redispatch volume by 155 TWh in 2040. Increasing it to 50%, on the other hand, reduces the total only by 55 TWh. While a certain share of CZ cooperation is therefore highly beneficial, marginal utility decreases with larger shares.

Figure 15: Sensitivity of total European redispatch to the share which can be resolved across bidding zone borders in the AGE scenario. For the reference case, a share of 30% was used.



Source: JRC analysis

4 Discussion

4.1 Viability of current redispatch arrangements

Our results suggest that the remedial actions necessary to achieve a feasible dispatch in the European system will increase massively in volume. In at least two of the three scenarios, the simulated redispatch volumes raise serious questions whether the system remains operable with the current mechanisms: In the AGE and BAU scenarios, the European redispatch volumes in 2040 match or exceed the total current electricity demand in large European countries such as Germany or France.

The approach we selected to model redispatch mirrors a cost-based redispatch approach. In systems with market-based redispatch, this redispatch volume might increase even further, as gaming opportunities might lead to further strain on the grid[11] (Hirth et al., 2019). But even the cost-based redispatch approach could well reach its limit: According to our assessment, a substantial share of power would be traded outside the market, through bilateral agreements (compare **Figure 12**). As soon as redispatch activation became predictable, which is likely given the large volumes forecasted, generators might ask for higher financial compensation to be included in the respective bilateral agreements. They could further adjust their bidding behaviour in the market to increase the likelihood of being activated for redispatch by the TSO. In this way, inc-dec gaming could occur in a cost-based system as well, though harder to detect as bilateral agreements are less transparent than market outcomes. It is further unclear what kind of effort would be required on the TSO side to correct the market outcome under these circumstances, as a large amount of redispatch orders would have to be coordinated – not only in the control area of the TSO, but also with neighbouring control areas.

In the XGE scenario, which foresees that total circuit length in every European country is expanded by more than a third, redispatch levels could potentially still be manageable. They describe a world in which many countries in Europe have to deal with redispatch volumes in the order of magnitude that occurs in Germany today. But even in this case, further investigation would be needed, as the system described is much more volatile than currently, and could therefore lead to more complex redispatch requirements. The challenge of coordinating large redispatch volumes between neighbouring TSOs could further remain a challenge.

It further needs to be stressed that we did not perform an economic viability assessment of the available power plants, but assumed that sufficient amounts of capacity will be available in the right places. This might well be an assumption that is too optimistic, as there are currently no market incentives in the European zonal markets to build dispatchable power plants in those locations where they are needed to enable a feasible redispatch. In Germany, for example, power plant capacities for redispatch are mostly required in the South, while building new capacity might well be more economic in the North, as LNG and hydrogen terminals are and will be located there.

4.2 Inefficient siting decisions

Downward redispatch is increasingly often provided by renewable generation, which reduces the amount of low-carbon electricity that is actually being consumed. We assess that between 111 and 310 TWh of renewable electricity are at risk of being curtailed due to grid congestion in 2040. This issue could likely be addressed by steering better to which locations renewable capacity is deployed to. Currently, the trade-off between higher capacity factors and minimizing strain on the grid is insufficiently accounted for in renewable auctions in Europe. Locational investment incentives, such as locational renewable auctions, could reflect the cost of grid integration of renewable projects and lead to a renewable build-out that minimizes curtailment and grid expansion.

We furthermore find that the incentives for hydrogen production are geospatially misaligned with the physical reality in the grid. This appears to be especially critical towards 2040, due to the high domestic production volumes, which result in 37 – 78 TWh of additional redispatch requirements. It further implies that hydrogen is being produced from dispatchable generation. Depending on whether fossil generation is still in the system, this is inefficient at best, and might even lead to an increase in carbon emissions. The impact of flexible demand from heat pumps and electric vehicles, on the other hand, appears to be much smaller. This is good

[11] Compare also section 3.6 which features a more detailed discussion of redispatch markets.

news, as there is more freedom to where hydrogen production is sited, while the electrification of domestic end uses is largely predetermined by where people live.

4.3 A possible way forward

To address these issues, investment and operational incentives should be improved. On the one hand, steering more actively where renewable and hydrogen generation is placed appears promising to reduce the volumes of redispatch that occur. It will likely take time to correct the current asymmetric deployment, as reforms need to be implemented, and project pipelines are already in development. It might therefore take a substantial time of continuous deployment under a new regime to achieve a better balance with regard to where generation and demand is located in the system.

On the other hand, it might need improved price signals in the wholesale market as well, to reduce redispatch volumes by improving the representation of the transmission grids in the market clearing process and setting the right incentives for flexible demand. The options to do so range from evolutionary approaches, such as bidding zone splits, to more radical options, such as locational marginal pricing at a high spatial resolution.

In the following section, we discuss a set of policy measures that can be considered to improve the situation in the grids and meet the challenge of grid congestion, as available grid capacity will likely remain limited for the foreseeable future.

5 Policy options to improve congestion management

There exist several options to address the issue of massively and rapidly increasing redispatch volumes. Some instruments represent an evolutionary approach, while others would imply a radical and complete overhaul of the regulatory system. We can furthermore distinguish these policy instruments based on whether they improve the siting of new infrastructure, or whether they improve the short-term operation of the system. A selection – without any claim to completeness – is discussed below.

5.1 Bidding zone splits

The European legislation includes bidding zone splits as *the* instrument to address structural bottlenecks (see Article 14 of the Electricity Regulation). By splitting zones along lines of structural congestion, these congestions are taken explicitly into consideration in the market clearing process, as they are defining the available transfer capacity between the new regions.

Pro: A significant advantage of splitting market zones is that it leaves the current market structure generally intact, while only changing the configuration of the market zones. Redispatch is reduced, as structural congestion is being taken into consideration at the borders of the bidding zones when allocating CZ capacity. A recent analysis found that German redispatch needs could be reduced by 35-65% by splitting the German price zone into two (THEMA and EWI, 2023). The instrument is further already part of the European legislation, which simplifies the political process towards improving price signals, compared to, for example, a more radical approach that would require rewriting large parts of the Electricity Regulation and the relevant Guidelines. Theoretically, bidding zones can be split until a high spatial granularity in the market is achieved. This would allow to increase the granularity of the market signals until alignment between market transactions and physical reality is largely achieved (Antonopoulos et al., 2020).

Con: In practice, however, the Bidding Zone Review (BZR) proves to be a lengthy process[12]. It is therefore unlikely to lead to a system without redispatch in the foreseeable future. Furthermore, there are no objectively correct bidding zone splits, and those that perform best given a certain set of key performance indicators at a certain point in time could be unsuitable several years later. On the one hand, this would produce a constant risk that market zones could be split, which investors would have to take into consideration when investing in a given market zone. (Maurer et al., 2018) therefore argued that a direct transition to nodal pricing would be advantageous over continuous bidding zone splits. On the other hand, there is a risk of implementing sub-optimal bidding zone configurations due to the lengthy process, as the physical reality in the grids may have changed again in the meantime[13].

Discussion: Given that structural bottlenecks, especially in the larger European zones, are getting worse rather than better, we recommend to implement those splits that address long-standing bottlenecks and prove to improve the market outcome. Increased risk through looming bidding zone splits cannot be neglected in general, can however also be addressed if required[14]. In the ongoing round of the BZR it can further be expected that market participants have already priced in the risk, as they are aware of the splits being discussed. These risks are therefore most likely already considered in recent investment decisions, and thus not a reason to refrain from implementing splits that improve the representation of structural congestion in the market-clearing process.

In the long-run, splitting bidding zones appears generally promising to improve the alignment between market transactions and the physical reality in the grid. Constant splitting, until both aspects are fully aligned, however, would be a very lengthy process as this would require a plethora of additional splits. Given the short timeframe until the EU aims to fully decarbonize and the time the current BZR is already in the making, taking this path down to full alignment seems to be quite ambitious.

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[12] According to ENTSO-E, the results of the BZR are expected in December 2024 (ENTSO-E, 2024). The current round of the BZR kicked off in 2019, with the decision on the methodology being issued in November 2020. Since then, the most promising alternative configurations have been determined, and are currently under investigation. This means that the current round is expected to take roughly 4 years for the determination and investigation of alternative configurations.

[13] For example due to additional deployment of renewables or increased electrification which could lead to both a higher or lower imbalance inside a given zone, depending on the areas in which these processes would predominantly increase supply or demand.

[14] For example by grandfathering FTRs to recent investments that have been taken in the run-up to the announcement of a bidding zone split.

5.2 Redispatch markets

Given the large volumes of redispatch forecasted, the question must be raised whether these exceed a level that can be handled through cost-based redispatch arrangements, i.e. redispatch based on bilateral agreements between TSO and power plant operators – also given potential transparency issues. A seemingly obvious answer is the introduction of a market-based system as is already the case in Spain (CEER, 2021).

Pro: While redispatch is still managed through bilateral contracts in a substantial part of Europe, introducing redispatch markets would allow for the participation of loads, storage and other, often smaller market participants to provide redispatch services. A market arrangement would further increase transparency, as above-mentioned bilateral contracts are usually not public. In addition, redispatch markets would facilitate CZ redispatch measures, which, according to our results, could minimize the amount of remedial actions necessary to achieve a feasible dispatch.

Con: The big downside of redispatch markets is the fact that they create the possibility of inc-dec gaming. As shown by (Hirth et al., 2019), the parallel existence of two market sessions with different spatial granularity (for example a zonal spot market in parallel to a nodal redispatch market) creates gaming possibilities which do not require the presence of market power. According to their analysis, replacing the cost-based redispatch arrangement in Germany with a market-based approach could increase the redispatch volume by 300-700% by 2030. This is in line with (Voswinkel, 2019) who calculated a 50% increase in redispatch volume in CWE in the current setting. Both case studies considered in conjunction could further suggest that gaming opportunities increase with additional renewable deployment.

Discussion: Even though setting up a market-based approach may appear as an intuitive solution to large and increasing redispatch volumes, research suggests that redispatch markets can exacerbate bottlenecks, thereby further draining an already scarce resource. Given the large volumes of renewables that are projected to come on line in the next two decades, gaming opportunities could further increase. The rollout of redispatch markets therefore does not appear to be *the* solution for grid congestion issues in the European system.

5.3 Locational renewable auctions

The increase in redispatch volumes across the EU is closely associated with the current way of deploying renewable capacity. Most auctions do not take (grid) location into consideration when awarding remuneration contracts. One exception to this is the German auctioning system, which limits deployment in a predefined grid development area (Bundesnetzagentur, 2019), while simultaneously correcting bids for the quality of the resource (Bundesministerium für Wirtschaft und Klimaschutz, 2016). Given that German redispatch volumes continue to increase (ACER, 2023), it appears as though these incentives are insufficient to meet the challenge ahead.

To maximize grid utilization and limit the amount of redispatch produced by additional renewable installations, locational auctions can be designed which take the grid into consideration when allocating renewable capacity. This can be done in two ways. As proposed in (Thomaßen et al., 2023), bid selection can be done by a model, as is current practice for accepting bids in the short-term electricity markets. Submitted bids can be added to a capacity expansion model, which selects the combination of bids that fulfils a given target, while minimizing the overall system cost. This would reward those projects, which bring the largest benefit to the system – which are not necessarily the ones with the lowest LCOE.

As an alternative, mark ups and mark downs can be determined for each grid location, as previously applied in the Mexican renewable auctions (IRENA, 2017). These are determined by a nodal electricity market model, and reflect the benefit of additional capacity of a certain type of technology in a given location. The locational adders are then applied to the submitted bids, decreasing the bid of projects in favourable locations, while penalizing projects that would increase bottlenecks in the system, making beneficial projects more competitive.

Pro: Locational renewable auctions allocate renewable capacity where it brings the largest benefit. In this way, the build out of renewables might even reduce redispatch volumes, as the distribution of renewable capacity inside the zones gets more even. This is further supported by the fact that locational adders in Mexico's second auction dropped significantly – even though the same method was applied (IRENA, 2017).

Con: While locational renewable auctions will likely improve the situation, they cannot be thought of as a short-term solution. Large volumes of renewable capacity are already deployed, and the resulting challenges to the grid can only slowly be corrected by deploying more capacity in other areas. In addition, installing renewables in grid-friendly locations (for example close to demand), will likely imply going for sites with a lower capacity factor.

Discussion: Locational renewable auctions are a no-regret option as they deploy renewables in locations that are beneficial to the system, rather than exacerbating current bottlenecks in the grid. At the same time, they are not an all-out solution. Additional policy action will therefore likely remain necessary. Nonetheless, locational renewable auctions appear to have the potential to be a relevant part of an effective policy mix that addresses the European grid challenges. For example, in addition to bidding zone splits that address the severest bottlenecks in the European system. Further work is necessary to quantify the impact such a policy would have on redispatch volumes and grid bottlenecks in the medium to long term, as well as on the total amount of generated renewable electricity, due to the fact that renewable capacities would often be deployed in locations with a worse primary resource.

5.4 Locational capacity markets

Similar to locational renewable auctions, capacity markets can be equipped with a locational price signal. PJM and CAISO, for example, introduced zones based on which capacity has to be procured, while Chile relies on a price-based mechanism that aligns with their nodal electricity market design (Eicke et al., 2020). (Thomaßen et al., 2023) further propose a capacity market design which picks projects based on a capacity expansion model – similar to the locational renewable auction mechanism referenced in section 5.3.

Pro: The main advantage of locational signals in capacity markets is that they can ensure that the capacity necessary for redispatch is available. The necessity is shown, for example, by the fact that Germany procured four new power plants for the South of Germany, which are not participating in the market, but are only designated for redispatch services (Eicke et al., 2020). If the location of firm capacity is not considered in the procurement process, it is up to other economic factors – such as existing grid connections or easy access to other infrastructure for gas or hydrogen – to decide where it is built. These do not necessarily align with the system needs.

Con: Locational capacity markets do little to nothing address the issue itself, which are increasing redispatch volumes due to asymmetric renewable deployment. This is due to the fact that they will likely add generation to the system with a high marginal cost, at the end of the merit order[15]. The actual dispatch will therefore change little, as renewables are dispatched first.

Discussion: While locational investment signals within capacity markets can improve and maintain the ability to organize redispatch, they do not tackle the issue of high redispatch volumes itself. Since zonal markets do not have the ability to steer where capacity is built inside a given zone, the introduction of locational capacity reliability mechanisms might become *inevitable*. Such a case could arise if power plants are not constructed in the right locations to keep redispatch feasible, or capacity in vital areas is threatened to be decommissioned due to low economic viability.

5.5 Locational grid charges

Pricing access to the grid or its usage can help avoiding and reducing existing congestion if these charges have a locational component and reflect tensions in the grid. There exist two different principles that can help steering investments in new infrastructure to beneficial sites – deep connection charges and grid usage charges (Eicke et al., 2020). In systems where deep connection charges are applied, the developers of newly built power plants need to pay for all the downstream grid investments that become necessary to connect the plant to the grid. This does not only include investments to connect it to the nearest substations, but also capacity upgrades in the grid behind it that are necessary due to the additional expected infeed. Grid usage charges, on the other hand, can reflect a locational component as well, for example by reflecting the costs of the lines used by a given consumer or producer (Olmos and Pérez-Arriaga, 2009).

Pro: Locational grid charges, both for connecting as well as for using the grid, can be a comparably low-level intervention to correct investment signals, as the functioning of the market is not affected at all. At the same time, they can substantially affect an investor's cost-benefit analysis and thereby set incentives to invest in

[15] Generation with low marginal costs, such as renewables or nuclear are unlikely to be additionally deployed due to a capacity market. This is due to the low capacity credit of renewables, and the long build out times for nuclear power plants.

locations that are beneficial to the system, rather than increasing congestion in the grid. In addition, they do not represent a completely new concept, as deep connection charges are already applied in various European countries, including inside the EU (ENTSO-E, 2020). If grid charges are further implemented in a time-varying way, they can create incentives for a grid-friendly operation of demand response and storage.

Con: Deep connection charges can create a first-mover dilemma which can discourage investments: First movers might finance grid infrastructure that is later used as well by additional investments – made by a competitor – in the same area. On the other hand, locational grid usage charges might be difficult to forecast years ahead, and therefore create uncertainty with regard to new investments.

Discussion: Locational grid charges can play a role in steering investments into the right direction and therefore – similar to locational renewable auctions – can contribute to relieving congestion in the medium to long term. To lower redispatch volumes in the short-term, grid charges would have to be time varying and reflective of the situation in the grid. Important appears to be transparency on the level applied in each location, so that investors can consider locational grid charges early on, when deciding where to place a new investment. Generally, it should be carefully assessed whether deep connection charges should be applied, due to the associated first-mover dilemma, which could discourage investment in a time when power sector investment is vital to achieving the climate targets.

5.6 Locational marginal pricing

Going further than introducing locational *investment* signals, the introduction of locational marginal pricing[16] (LMP) would drastically increase the geographical resolution at which the market is cleared, thus affecting as well *operational* decisions. While LMP systems are currently not applied in Europe, they are present in all US power markets, and several South American markets, such as Chile and Mexico (Eicke et al., 2020).

Pro: The advantage of an introduction of LMP is that it would achieve a highly-efficient dispatch without the necessity of expensive and potentially increasingly-complex redispatch. Instead, market prices would reveal where congestion occurs in the grid. An LMP system would, for example, set incentives to use storage for congestion management: In an hour with high renewable surpluses, during which not all generated energy could be transported due to grid bottlenecks, operators would fill their storages, as the prices would be low. As soon as renewable production was lower, and available grid capacity to higher-priced areas was again available, these storages would discharge their electricity. In this way, an LMP system provides additional information on the system's state to market participants and incentivizes them to use their assets in a system-friendly way.

Similar benefits could be expected with regard to dealing with forecast errors, as deviations would reveal themselves at a higher geospatial granularity than currently. In large zones, regional deviations in forecasted renewable production could, for example, cancel each other out. In an LMP system, the desire of market participants to adapt their positions once a forecast update came in would reveal where too much and where too little energy was sold. This information can be useful for other market participants to adapt their bidding strategies or their consumption profile in a way that benefits the systems, as well as for grid operators, as it provides them more detailed information on what flows can be expected. The issue of forecast errors will grow in relevance with the upscaling of variable renewable capacity in the system.

Con: While the operational benefits of an LMP system are well documented, the effect on investment decisions is much less clear. (Brown et al., 2020) found only a low correlation between high nodal prices in Texas and power plant investments. In this context, (AFRY, 2023) argue that the complexity of an LMP system hinders market participants to forecast prices well, which could keep them from making those investment decisions that are most profitable, and thereby most beneficial to the system.

Introducing an LMP system would further imply a fundamental change to the way electricity is traded in Europe, which would likely further increase uncertainty in the short to medium term, until all associated reforms were implemented. Potentially, reforms would not only affect the geographical resolution at which the market is cleared, but also other aspects: As portfolio bids would lose much of their advantages to

[16] In this study, we use LMP as a description for a system which sufficiently aligns market transactions with the physical reality to avoid (almost) all redispatch by drastically increasing the number of market zones considered in the market clearing process. This does not necessarily mean that a full nodal resolution needs to be applied, which would go down to every substation at transmission system level.

traders[17], it could be consistent to implement unit-based bidding and a centralized dispatch model at the same time. An introduction of LMP would therefore take several years to overhaul the Electricity Regulation and the Guidelines, with intense discussions, and fundamental opposition from several stakeholder groups to be expected.

Once implemented, LMP would lead to redistribution effects, as the price of electricity would be determined individually at each node of the system. This might make additional instruments necessary to handle these effects, for example the grandfathering of financial transmission rights (FTRs) to at least some stakeholders.

Discussion: The introduction of LMP would align to a far degree the market outcome with the physical reality. It is therefore not a fix, but a solution to the redispatch issue which improves the market design by avoiding costly and intransparent corrections of the market outcome altogether. Redistribution effects between consumers and producers would inevitably occur, yet could be taken care of by grandfathering FTRs if deemed necessary (Kunz et al., 2016).

It is much less clear, however, how much it would affect investment decisions, as evidence is scarce that more diversified price signals achieve investments in the right locations. If an LMP system should be introduced, we would therefore recommend to nonetheless pair it with additional instruments that steer investments to the right locations, such as locational renewable auctions, locational capacity markets and/or locational grid charges. The necessary regulatory changes would furthermore increase the risk associated with investments in electricity infrastructure at least temporarily, until it was clear what changes the associated reforms would deliver to the market.

Given that an introduction would take several years to be fully implemented, we recommend to carry out a cost-benefit assessment of LMP, weighing the benefits regarding the operation of a climate-neutral power system that is largely based on variable renewables with the costs and complexity of implementation.

[17] One main advantage of portfolio bids to traders is that unforeseen contingencies can be dealt with inside the portfolio. If portfolios had to be nominated at the level of – for example – substations, they would lose much of the associated flexibility.

6 Concluding remarks

In this study, we have assessed different scenarios and their implications for the operability of the European electricity grids up until 2040. The scenarios differ in the assumed rate of grid expansion that takes place in the European system in the meantime. Out results suggest that the uncoordinated deployment of variable renewable generation will lead to severe bottlenecks in the grid, which will lead to massive increases in redispatch requirements. While 2022 saw 50 TWh of redispatch in Europe, it could increase to 165 TWh in 2030 and 274 TWh in 2040 in the XGE scenario, which assumes an expansion of the European transmission grid by 35%. In the BAU scenario – which foresees that grid expansion progresses only at historic rates – redispatch could even be as high as 374 TWh in 2030 and 809 TWh in 2040. In systems with cost-based redispatch, this implies a large volume of energy being traded outside of the market. In systems with market-based redispatch, our estimates might still be conservative. According to the scientific literature, redispatch needs could well be further increased due to the possibility of inc-dec gaming.

These redispatch volumes further have implications for the production of low-carbon electricity: In the BAU scenario, grid-related curtailment of renewables could be as high as 121 TWh in 2030 and 310 TWh in 2040. The current zonal configurations further lead to inefficient incentives for hydrogen production. A conservative estimation resulted in 10-14% of redispatch needs in 2040 being triggered by electrolysis.

To meet the challenge posed by the large-scale deployment of distributed renewables, it appears necessary to steer more actively where power system infrastructure is being built. This applies primarily to renewables and electrolysis, as these have a direct impact on redispatch needs, but also to dispatchable generation, as redispatch could become infeasible if there is not enough capacity on the right side of the bottleneck.

Additionally, it could be necessary to further increase the spatial resolution of the market price signal, especially since it will take time to achieve a better balance in the system through continuous deployment of renewables. In this context, price signals at a higher spatial granularity can improve the incentives for storage and demand response to engage in congestion management and thereby help to deal with existing congestion in the grid.

Several policy options exist to address the challenges outlined above. To steer deployment of power system infrastructure into locations beneficial to the system, renewable auctions and capacity markets can be set up to incorporate locational price signals. Similarly grid connection and usage charges can contain a locational component to reflect the value of generation at a given location.

Operational price signals can be improved by bidding-zone splits, which are a straightforward way to better reflect structural congestion in the market clearing process. The European legislation further already features all the necessary provisions. Further assessment is necessary whether increasing spatial granularity in an evolutionary manner, through bidding zone splits, is sufficient for a successful energy transition, or whether a transition towards an LMP system could become necessary. To this aim, we recommend to carry out a cost-benefit assessment of LMP, weighing the benefits regarding the operation of a climate-neutral power system with the costs and the complexity of implementation.

Annexes

Annex 1. Candidate HVDC projects

Table 1: Candidate HVDC projects

Start	End	Length (km)	Latitude start	Longitude start	Latitude end	Longitude end
Radstede (DE)	Kriftel (DE)	712	8.195159	53.24083	8.531909	50.04795
Radstede (DE)	Marxheim (DE)	712	8.195159	53.24083	8.449776	49.511
Wilhelmshafen (DE)	Lippetal (DE)	249.6	8.073004	53.54102	8.152376	51.66527
Heide (DE)	Polsum (DE)	379.2	9.1073	54.19209	7.05352	51.62467
Hemmingstedt (DE)	Klein Rogan (DE)	192	9.076526	54.14386	11.35022	53.60511
Poeschendorf	Klein Rogan (DE)	157.2	9.49054	54.03755	11.35022	53.60511
Nuettermoor (DE)	Streumen (DE)	549.6	7.436669	53.26229	13.4024	51.35616
Alfstedt (DE)	Obrigheim (DE)	559.2	9.068675	53.54723	9.092289	49.35086
Buechen (DE)	Boeblingen (DE)	654	10.61514	53.47578	9.004249	48.68374
Metz(FR)	Magnanville (FR)	392.4	6.159215	49.11042	1.671295	48.97103
Magnanville (FR)	Colomby (FR)	288	1.671295	48.97103	-1.47629	49.46098
Looberghe (FR)	Magnanville (FR)	264	2.243729	50.90742	1.671295	48.97103
Montcornet (FR)	Genelard (FR)	412.8	4.653053	49.84119	4.256515	46.59095
Genelard (FR)	Baillargues (FR)	396	4.256515	46.59095	3.996048	43.65196
Tychy (PL)	Jaroslawiec (PL)	620.4	19.0011	50.12176	16.54232	54.53115

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List of abbreviations and definitions

AC	Alternating current
ACER	Agency for the Cooperation of Energy Regulators
AGE	Ambitious grid expansion scenario
BAU	Business as usual scenario
Bn	Billion
BZR	Bidding Zone Review
CWE	Central Western Europe region
CZ	Cross zonal
DC	Direct current
ENTSO-E	European Network of Transmission System Operators for Electricity
EU	European Union
EUR	Euro (currency)
EV	Electric vehicle
FBMC	Flow-based market coupling
FRM	Flow reliability margin
GDP	Gross domestic product
GSK	Generator shift key
HVDC	High voltage direct current
JRC	Joint Research Centre of the European Commission
km	Kilometre
LMP	Locational marginal pricing
LNG	Liquefied natural gas
LCOE	Levelised cost of electricity
minRAM	Minimum remaining available margin
MACZT	Margin available for cross-zonal trade
MWh	Megawatthour
NDP	Network development plan
NTC	Net transfer capacity
PV	Photovoltaics
TSO	Transmission system operator
TWh	Terawatthour
TYNDP	Ten Year Network Development Plan
XGE	Extreme grid expansion scenario

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EU open data

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