ACER

European Union Agency for the Cooperation of Energy Regulators

Increasing cross-zonal capacity and system flexibility in Southeast Europe

ACER report to the Energy Union Task Force

2026 Monitoring Report

20 May 2026

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Executive summary

Following the significant increase in electricity prices observed in Southeast Europe during the summer of 2024, the European Commission asked ACER to assess the feasibility of introducing measures to increase cross-zonal capacities and system flexibility in the region, as part of the efforts of the Energy Union Task Force to ensure the affordability of electricity supply. The objective of this assessment was to identify actions that could help prevent or mitigate similar price developments in the future.

Average day-ahead prices in Southeast Europe at 19:00 CEST – July to September 2024 (EUR/MWh)

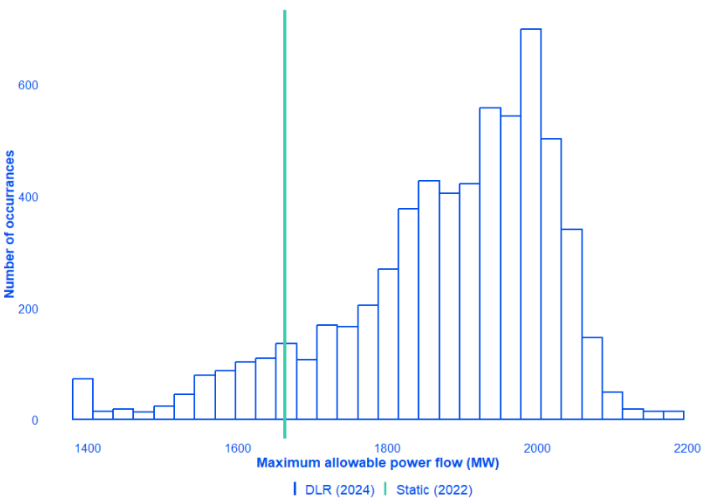
Source: ACER calculation based on ENTSO-E TP data.

ACER's assessment found that the 2024 price spikes were driven by a combination of tight regional supply-demand conditions, and limited ability to import electricity from the rest of the EU. Periods of high demand, often linked to extreme weather conditions, coincided with limited flexible supply capable of responding rapidly to changing system needs. The increased reliance on a relatively small pool of flexible generation assets to meet evening demand peaks placed strong upward pressure on prices during evening hours. At the same time, limited cross-border transmission capacity, exacerbated by planned line outages, reduced the possibilities for importing lower-priced electricity from neighbouring markets.

Although price levels in 2025 did not reach the highs recorded during the summer of 2024, significant price differences between Southeast and Central Europe persisted throughout 2025 and into the first months of 2026. This suggests that the developments observed in 2024 were not solely the result of exceptional circumstances but also reflected more structural challenges affecting the region. Addressing these challenges requires both short-term measures and longer-term structural action.

Optimising the existing network can increase cross-border trade towards Southeast Europe and mitigate electricity price volatility

Example of implementation of dynamic line rating in capacity calculation – 2022 and 2024 (MW)



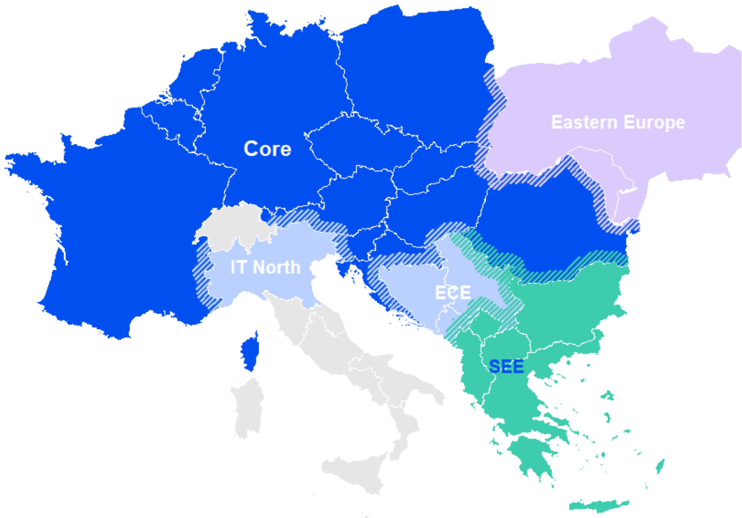
Source: ACER calculation based on JAO Publication Tool data.

In the near term, priority should be given to accelerating lower-cost and faster-to-deploy upgrades that can increase the capacity of the existing network. Technologies such as dynamic line rating, which allows the admissible power flow of a line to be adjusted based on measured or forecasted ambient conditions, and the upgrading of traditional power lines with high-temperature low-sag conductors can unlock additional transmission capacity more quickly and at lower cost than conventional grid expansion. These solutions should be assessed by all TSOs in Central and Southeast Europe and accelerated on congested areas of the network, particularly ahead of future periods of seasonal stress.

At the same time, stronger regional coordination remains essential. Improvements in regional outage planning coordination processes are necessary to ensure that the impact of outage planning in market outcomes is minimised. A more efficient use of curative remedial actions in capacity calculation can help optimise the capacity made available to the market during periods of stress, while ensuring operational security.

Moreover, the Southeast Europe region would benefit from the implementation of existing EU legal and regulatory requirements aimed at deepening market integration. This includes completing the implementation of the minimum 70% requirement, particularly in Central Europe, extending market coupling to non-EU neighbours in Southeast Europe, and progressively introducing flow-based capacity calculation and allocation in Southeast Europe.

Newly established capacity calculation regions in Central and Southeast Europe



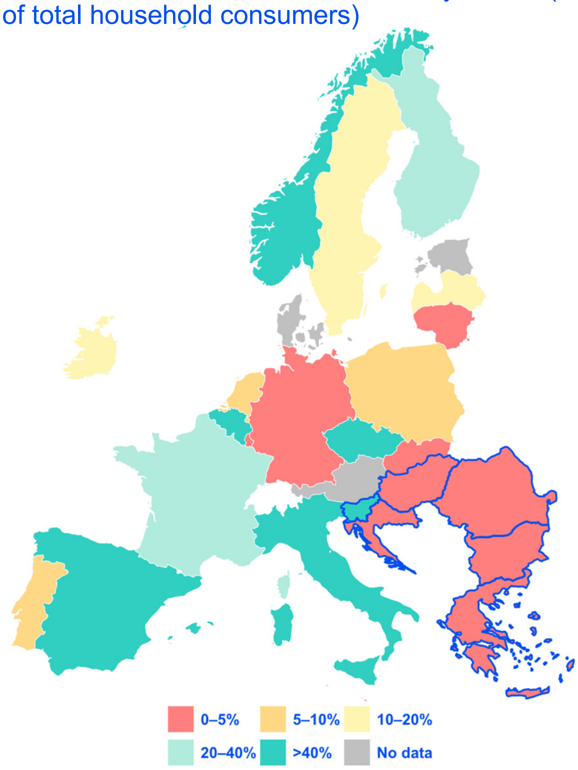
Source: ACER elaboration.

Structural integration of electricity markets in Southeast Europe requires acceleration of network investments

Beyond operational improvements, the observed price patterns also point to the need to address structural bottlenecks in the network between Central and Southeast Europe, through targeted grid reinforcements. Persistent price differences between Southeast Europe and the rest of the EU indicate that network constraints continue to limit the effective integration of the region with neighbouring markets.

Where justified by their expected benefits, projects with a high impact on regional market integration and security of supply should be prioritised to support faster delivery. In this context, effective cost-sharing mechanisms remain essential to ensure a fair distribution of costs and benefits across the Member States concerned, particularly where the main benefits accrue beyond the Member State in which the investment is performed.

Adoption of time-varying retail contracts among households across the EU and Norway – 2024 (% of total household consumers)



Source: ACER calculation based on NRA data.

Unlocking system flexibility can bridge the gap between central and evening hours of the day in Southeast Europe

Finally, reducing the frequency and severity of future price spikes will also require greater system flexibility. This includes removing market and regulatory barriers to participation of distributed energy resources, as well as mobilising investments in storage and other flexible generation, so as to improve the system's ability to respond to sharp changes in demand and supply, particularly during the evening peaks.

Stronger participation of demand in wholesale markets, together with the further deployment of short-term flexibility resources, would improve the resilience of electricity systems in Southeast Europe, increase competitive pressure during tight market periods, and support more stable and efficient price formation in the region.

In conclusion, the price spikes observed in Southeast Europe during the summer of 2024 were likely not an isolated event caused only by exceptional weather conditions or specific network maintenances. They also reflect deeper structural challenges associated with the regional supply-demand balance, market structure and degree of interconnectivity. Deeper integration of Southeast Europe with the rest of the EU, together with increased system flexibility, can help mitigate future periods of system stress in the region.

List of abbreviations

Abbreviation	Term in full
ACER	European Union Agency for the Cooperation of Energy Regulators
ATC	Available Transfer Capacity
CBA	Cost-Benefit Analysis
CCR	Capacity Calculation Region
CEST	Central European Summer Time
CET	Central European Time
CGM	Common Grid Model
CNE	Critical Network Element
CNEC	Critical Network Element with Contingency
CNTC	Coordinated Net Transfer Capacity
CRA	Curative Remedial Action
DLR	Dynamic Line Rating
ECE	East-Central Europe
EE	Eastern Europe
ENTSO-E	European Network of Transmission System Operators for Electricity
EUTF	Energy Union Task Force
F_{max}	Maximum flow on critical network elements, respecting operational security limits
HTLS	High-Temperature Low-Sag
HVDC	High Voltage Direct Current
IDA	Pan-European intraday auctions
IGM	Individual Grid Model
JAO	Joint Allocation Office
MACZT	Margin Available for Cross-Zonal Trade
MTU	Market Time Unit
NRA	National Regulatory Authority
NRAO	Non-costly Remedial Action Optimisation
NTC	Net Transfer Capacity
RAM	Remaining Available Margin
RCC	Regional Coordination Centre
RES	Renewable Energy Sources
ROSC	Regional Operational Security Coordination
OPC	Outage Planning Coordination
OPI	Outage Planning Incompatibility
PATL	Permanent Admissible Thermal Limit
PST	Phase-Shifting Transformer
PV	Photovoltaic
SDAC	Single Day-Ahead Coupling
SEE	South-East Europe
SIDC	Single Intraday Coupling
SOGL	System Operation Guideline
SWE	South-West Europe
TATL	Temporary Admissible Thermal Limit
TEN-E	Trans-European Networks for Energy
TSO	Transmission System Operator
WB6	Western Balkans Six

Introduction

In response to a significant increase in electricity prices in Southeast Europe during the summer of 2024, the European Commission asked the Agency for the Cooperation of Energy Regulators (ACER) to assess the feasibility of implementing measures to increase cross-zonal capacities and system flexibility in the region[1]. This request, put forward through a letter delivered on 22 October 2025, formed part of the ongoing work of the Energy Union Task Force to ensure the affordability of electricity supply, and aimed to identify measures that could prevent or mitigate a recurrence of the price developments observed during 2024.

To comply with this request, ACER has been collaborating with Transmission System Operators (TSOs), Regional Coordination Centres (RCCs), and National Regulatory Authorities (NRAs) through a series of regular workshops involving all EU entities, and topical meetings involving dedicated experts from TSOs and RCCs. The primary objective of these interactions has been to identify existing operational best practices across the EU that can increase cross-zonal trade towards Southeast Europe, if applied in the relevant areas of the network.

Since many of the network limitations restricting trade towards Southeast Europe were located in Central Europe, the assessment also covered relevant Member States outside the region, notably Austria and Slovakia. Therefore, proposals to improve regional coordination processes, such as capacity calculation and regional outage planning coordination, have implications for both the Core[2] and South-East Europe capacity calculation regions.

Following the European Commission's request, ACER presented a preliminary set of proposals to the Energy Union Task Force on 9 March 2026 and committed to further elaborating these proposals in a final report. During this meeting, ACER received feedback from TSOs, RCCs and Member States on the proposals put forward, which was considered in the drafting of this final report. The final report was endorsed by ACER's Board of Regulators on 8 May 2026.

This assessment has primarily focused on practical measures to improve the utilisation of the existing electricity network through targeted investments or changes to operational processes. If rolled out, these measures would potentially increase cross-zonal capacities in the areas of the network that most hindered cross-zonal trade towards Southeast Europe during the summer of 2024. These measures are presented in Chapter 2.

Chapter 1 provides an overview of market conditions in Southeast Europe during the summer of 2024, serving as context for the proposals outlined in the subsequent chapters. Chapter 3 summarises previous proposals related to the activation of demand response and system flexibility that could help dampen price volatility in Southeast Europe. Lastly, Chapter 4 introduces structural market design and system planning measures that could strengthen price formation in the region.

ACER would like to express its gratitude for the valuable contributions received from all TSOs, RCCs and ENTSO-E, as well as all NRAs, in the preparation of this report.

[1] For the purpose of this assessment, the following EU Member States are generally referred to as 'Southeast Europe': Slovenia, Croatia, Hungary, Romania, Bulgaria and Greece.

[2] The Core CCR includes the bidding zone borders between the following Member States: Austria, Belgium, Croatia, Czechia, France, Germany, Hungary, Luxembourg, Poland, The Netherlands, Slovakia, Slovenia and Romania.

1. Market conditions in Southeast Europe

1.1. Electricity prices

During the summer of 2024, most bidding zones in Southeast Europe saw a significant increase in electricity prices, particularly during the evening hours, reaching values of up to 1000 EUR/MWh. During these high-price events, price spreads at several bidding zone borders in Central Europe rose to unprecedented levels, signalling insufficient availability of cross-zonal capacity to accommodate all the market's need for cross-zonal exchanges. This is summarised in Figure 1.

Figure 1: Average day-ahead prices in selected bidding zones in Central and Southeast Europe at 19:00 CEST – July to September 2024 (EUR/MWh)

Source: ACER calculation based on ENTSO-E Transparency Platform data.

Several fundamental drivers explain the market conditions observed in Southeast Europe during the summer of 2024. These drivers placed significant pressure on both the demand and the supply sides of the electricity system, contributing to periods of extreme-price events during the evening hours.

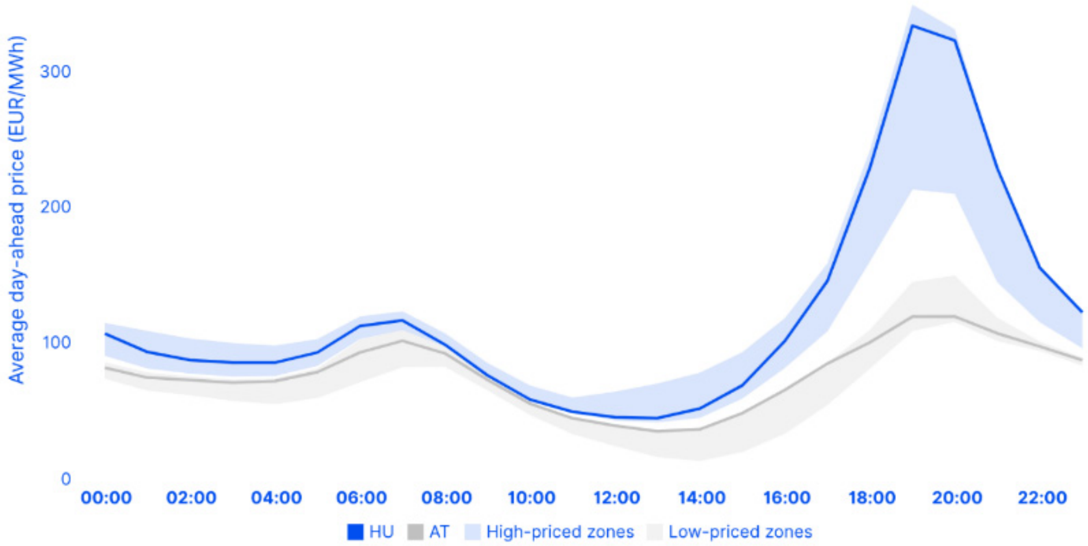
On the supply side, solar energy showed significant infeed levels during the central hours of the day, followed by a steep decline in output towards the evening. On the demand side, electricity consumption was significantly above average, with particularly high values during evening hours, driven by prolonged heatwaves affecting the region.

At the same time, the region faced limited availability of flexible resources capable of rapidly increasing production to compensate for the decline in solar generation. This reflected, among other factors, reduced availability of gas-fired power plants and low water levels in hydro reservoirs, as well as insufficient storage and demand response capabilities. In addition, increased electricity exports from EU Member States to Ukraine further intensified the tight regional supply-demand balance in Southeast Europe during the evening hours.

The lack of flexible resources to match the growing evening electricity demand with the steep decline in solar infeed resulted in a high need for exchanges from Central Europe towards the most affected bidding zones, which were constrained by limited cross-zonal capacity, including as a result of planned outages on network elements between Austria and Hungary.

Figure 2 shows the average daily profile of day-ahead prices in a selection of bidding zones across continental Europe. While electricity prices remain convergent during most periods of the day, there is a sharp decorrelation of prices between bidding zones in Central and Southeast Europe during the evening hours, coinciding with the demand peak of most Member States in Southeast Europe.

Figure 2: Average hourly day-ahead price in a selection of bidding zones in Central and Southeast Europe – July to September 2024 (EUR/MWh)



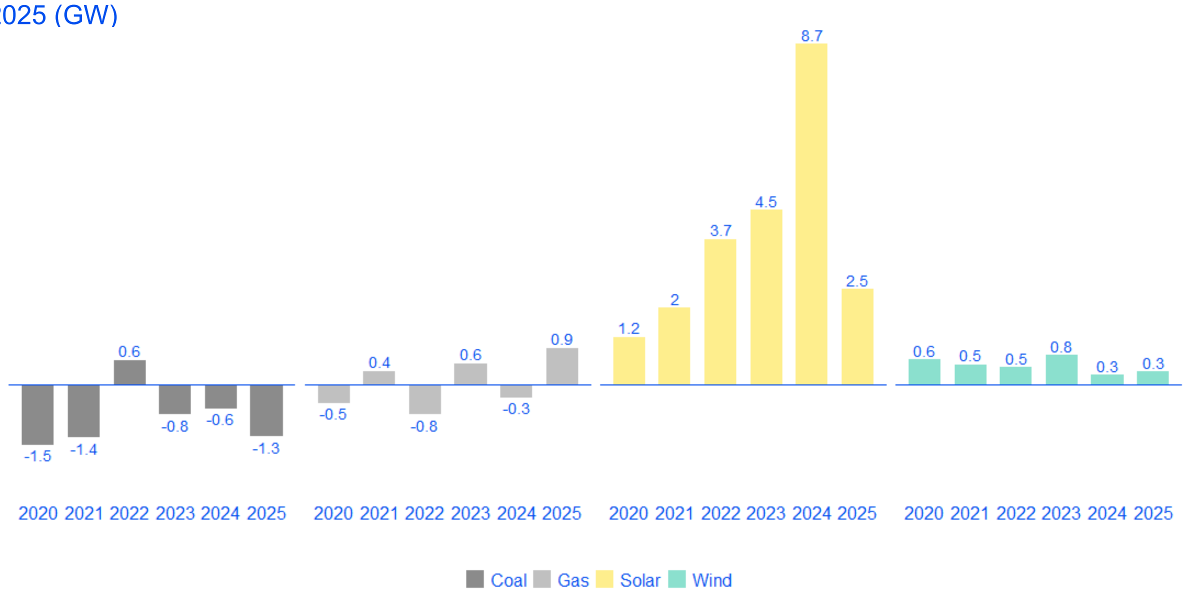
Source: ACER calculation based on ENTSO-E Transparency Platform data.

Note: Prices reflected in low-priced zones correspond to the following bidding zones: BE, FR, AT, CZ, DE-LU and NL; while prices reflected in high-priced zones correspond to the following bidding zones: GR, BG, RO, HU, SK, HR, SI and PL.

1.2. Generation structure

Over recent years, Member States in Southeast Europe have seen significant deployment of renewable energy sources (RES), particularly solar photovoltaic (PV). In 2024, new solar PV installations were roughly double those recorded in any previous year. At the same time, the region's conventional generation fleet has been on a declining trend, largely due to the decommissioning of coal-fired power plants. Figure 3 presents the yearly variation of reported installed capacity per generation technology in the region.

Figure 3: Yearly changes in installed capacity of selected technologies in Southeast Europe – 2020 to 2025 (GW)

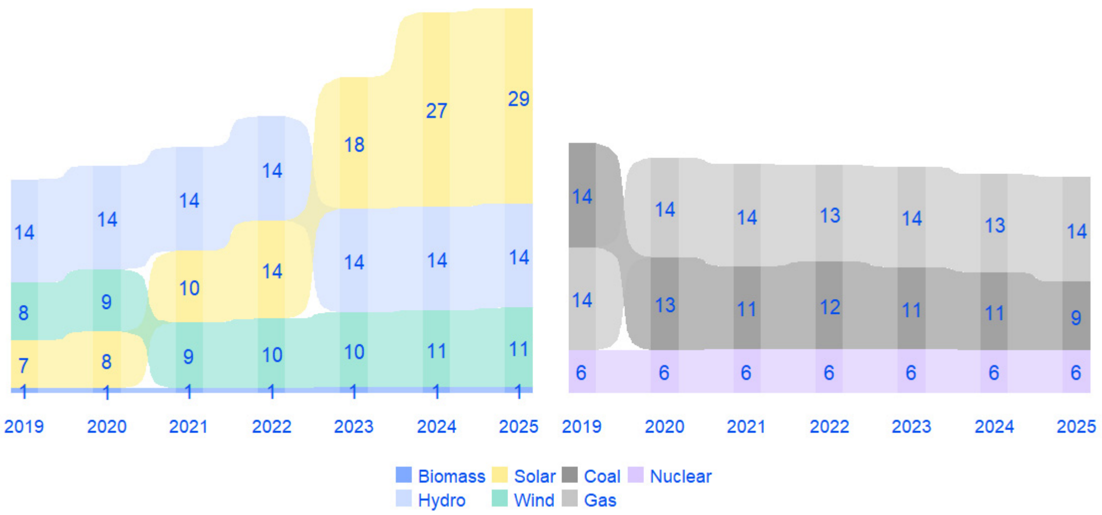


Source: ACER calculation based on ENTSO-E Transparency Platform data.

The following Member States are included in the figure: Bulgaria, Croatia, Hungary, Greece, Romania and Slovenia.

This trend has led to a significant transformation of the electricity supply structure in Southeast Europe, with solar PV capacity reaching 29 GW in 2025 and traditional generation capacity declining steadily over recent years, as highlighted in Figure 4. As a result, the region's power system has become increasingly reliant on variable renewable generation, while the availability of dispatchable capacity has not increased.

Figure 4: Evolution of installed capacity of selected technologies in Southeast Europe – 2020 to 2025 (GW)

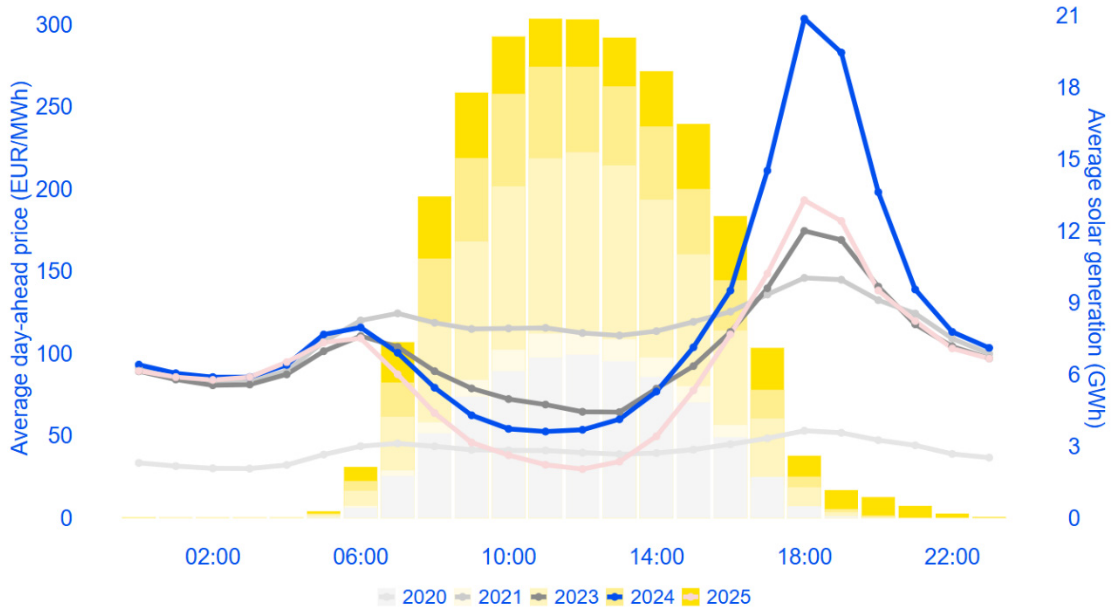


Source: ACER calculation based on ENTSO-E Transparency Platform data.

Note: The following Member States are included in the figure: Bulgaria, Croatia, Hungary, Greece, Romania and Slovenia. Installed generation capacity is presented for the end of each calendar year.

The current generation mix generally leads to high levels of solar PV output during the central hours of the day, putting downward pressure on electricity prices. In contrast, flexible generation, primarily from gas-fired power plants and hydropower, is required to meet evening demand peaks, contributing to higher prices during those hours. Gas-fired power plants may therefore be required to start up only to operate during a few hours, incurring significant start-up costs. This is highlighted in Figure 5.

Figure 5: Average hourly day-ahead price and solar generation for Member States in Southeast Europe during summer months – July to September 2020 to 2025



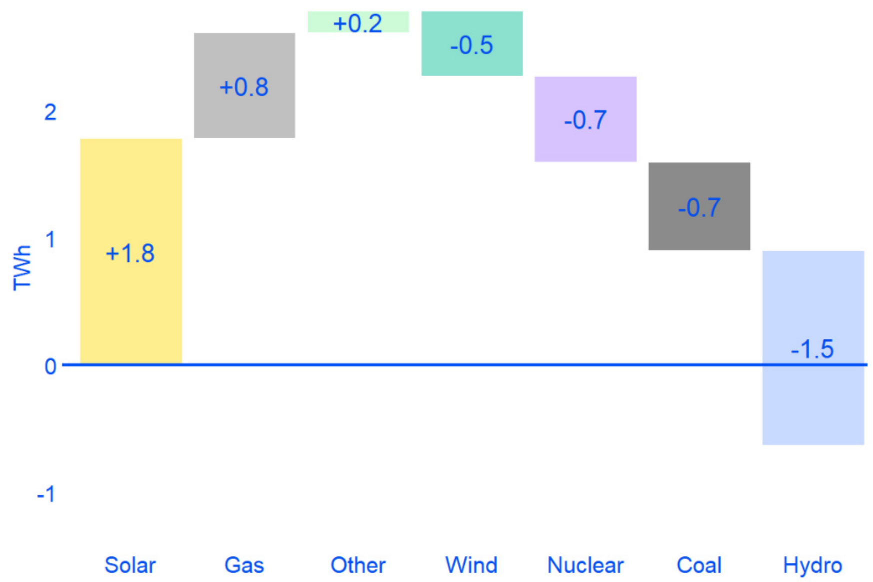
Source: ACER calculation based on ENTSO-E Transparency Platform data.

Note: The following Member States are included in the figure: Bulgaria, Croatia, Hungary, Greece, Romania and Slovenia.

The prices observed during summer of 2024 were influenced by these dynamics. A comparison of actual generation in summer 2024 with the corresponding period in the previous summer shows a marked increase in solar PV, which displaces coal-fired generation during central hours of the day. At the same time, the contribution of other non-flexible sources was lower than in the previous summer, as wind output declined and nuclear generation was reduced due to lower availability in Bulgaria, Hungary and Romania.

Flexible generation sources were therefore required to cover a larger share of residual demand, particularly during peak evening hours. However, hydro output, an important source of flexibility in the region, was significantly lower in 2024. As a result, gas-fired generation played a greater role in meeting demand peaks, as well as more imports of electricity from outside the region. These developments are illustrated in Figure 6.

Figure 6: Year-on-year changes in electricity generation in Southeast Europe during the summer, categorised by generation technology – July to September 2023 and 2024



Source: ACER calculation based on ENTSO-E Transparency Platform data.

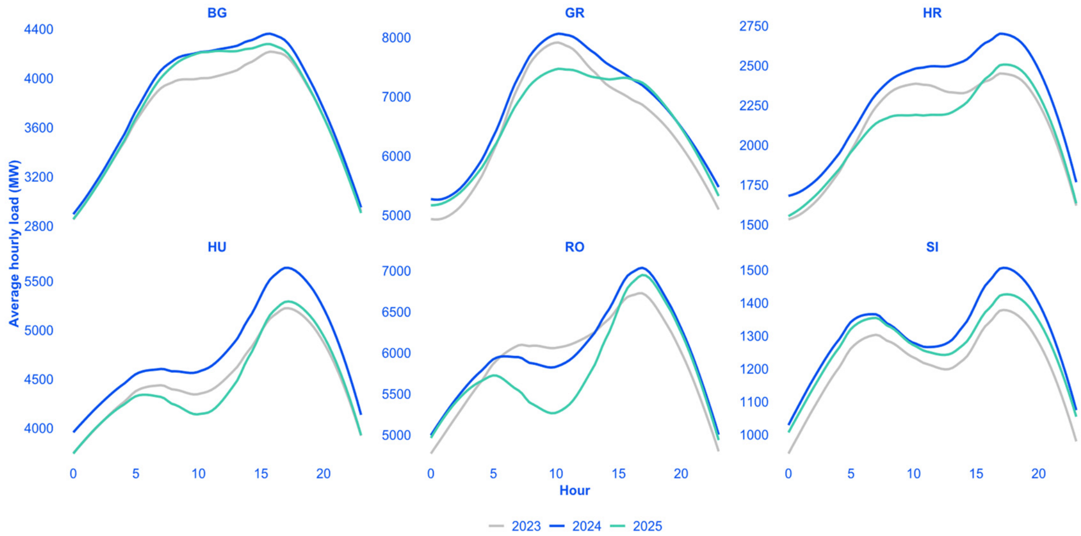
Note: Member States included in the figure are Bulgaria, Croatia, Greece, Hungary, Romania and Slovenia.

1.3. Electricity load

In summer 2024, electricity demand across Southeast Europe was unusually high compared to previous summers, following several weeks of persistently high temperatures across the region. This increase was particularly pronounced in Hungary, Slovenia and Croatia, where demand rose markedly above typical seasonal levels. The prolonged heatwaves are likely to have contributed to higher electricity consumption through increased cooling needs.

During the summer months, electricity demand in the region typically peaked in the evening hours, when temperatures remained elevated while solar generation was already declining. Greece is an exception to this pattern, with demand tending to peak in the morning hours of the day. Figure 7 compares the average electricity demand in the most affected Member States in Southeast Europe, during the summer months of 2023, 2024 and 2025. These demand patterns intensified pressure on the power system during the evening hours in the summer of 2024, contributing to the tight regional supply-demand balance.

Figure 7: Comparison of average daily load profile in Southeast Europe during the summer – July to September 2023 to 2025 (MWh)

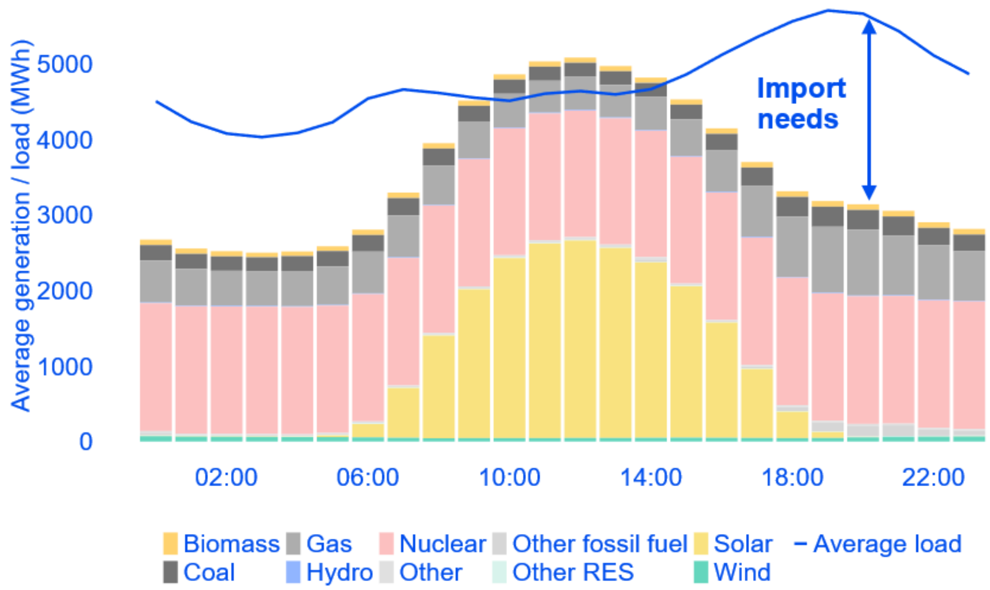


Source: ACER calculation based on ENTSO-E Transparency Platform data.

1.4. Cross-zonal electricity exchanges

The resulting generation and demand balance is characterised by high renewable infeed, mostly solar PV, in the central hours of the day and sharp increases in load in the evening hours, as temperatures remain elevated and solar output declines. As a result, the residual demand to be supplied by non-solar resources increases rapidly in the late afternoon and evening, creating a significant need for flexible resources to bridge this gap. This was particularly so for Hungary, as highlighted in Figure 8.

Figure 8: Average load and generation pattern in Hungary during the summer of 2024 – July to September 2024



Source: ACER calculation based on ENTSO-E Transparency Platform data.

This gap was covered, to a significant extent, by imports from neighbouring EU zones. In doing so, cross-border exchanges played a key role in meeting evening demand and preventing even higher prices, especially when domestic flexible generation was constrained or already fully utilised.

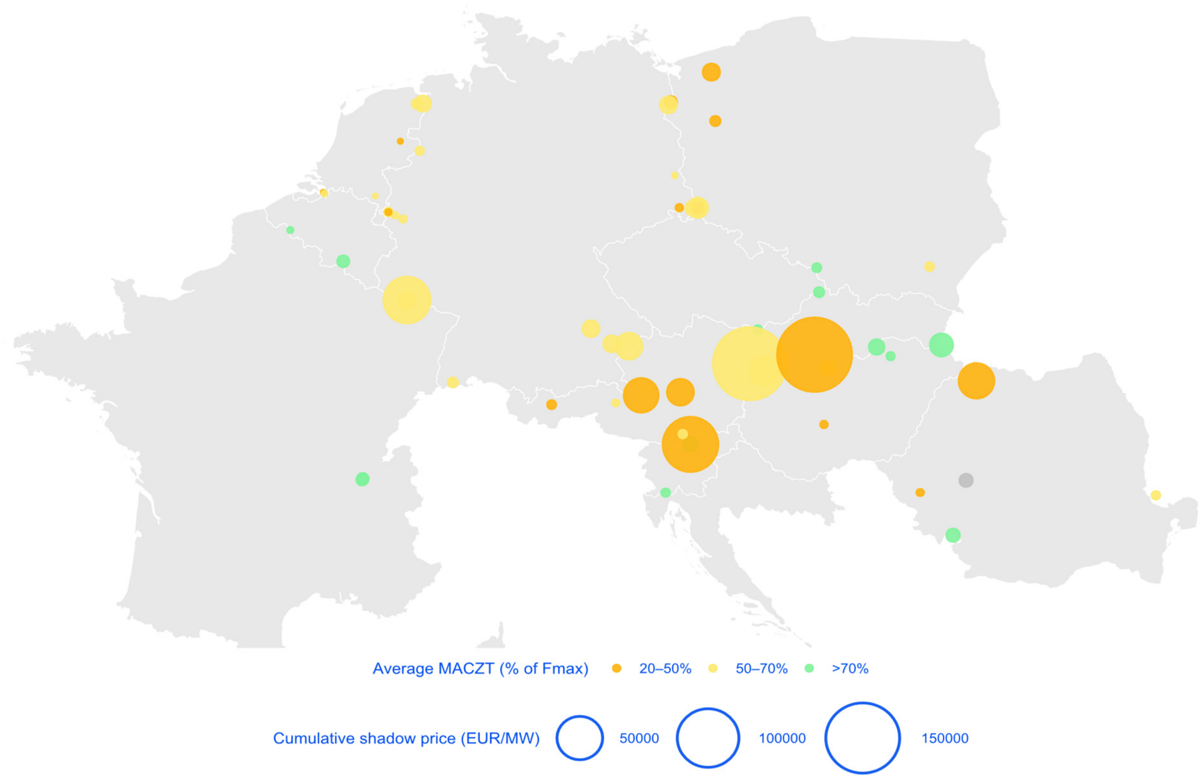
1.4.1. Exchanges within the EU

Electricity exchanges within the EU are an outcome of a welfare optimisation, within the limits of the network constraints defined by the TSOs. In the Core capacity calculation region (CCR), such network constraints are defined at the network element level, by means of a flow-based domain, while in the rest of continental Europe such network constraints are represented by border limitations to electricity trade, or Net Transfer Capacities (NTCs).

In the summer of 2024, available capacity in specific network elements in Central Europe proved insufficient to accommodate all needs for exchanges towards Southeast Europe. This is demonstrated by the observed shadow prices associated with network constraints in Central Europe, which are non-zero when a network constraint is binding the market coupling optimisation solution. These shadow prices represent the additional economic surplus of relaxing a given constraint (i.e. increasing its capacity) by a single MW.

The overview of network elements that limited additional trade in Central Europe during the evening hours of the summer months of 2024 is represented in Figure 9. The size of each entry represents how restrictive a given network element was to market coupling (i.e. single day-ahead coupling, or SDAC). The colour represents the margin made available for cross-zonal trade (or MACZT), which is further discussed in section 2.3.

Figure 9: Active network elements in Core flow-based market coupling during the evening peaks (18:00 to 22:00 CEST) – July to September 2024 (EUR/MW)

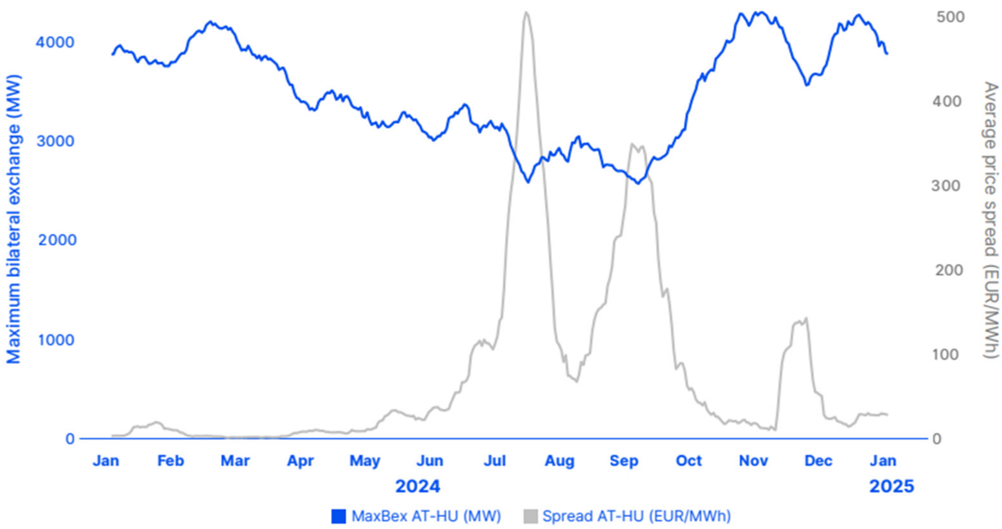


Source: ACER calculation based on JAO Publication Tool data.

Note: Cumulative shadow prices represent the additional socio-economic surplus that would have been generated in the day-ahead market by allowing for one extra MW of cross-zonal trade on a given network element, for all its contingencies, over the relevant period.

Available capacity was lower than usual during the summer period on the network elements that enable trade towards Southeast Europe. Figure 10 confirms that the periods with sharpest price differences between Austria and Hungary correlated highly with those periods where available cross-zonal capacity was lowest throughout the year. This may be partly explained by transmission assets undergoing maintenance in Central Europe during the summer, together with other seasonal effects.

Figure 10: Two-week rolling average of the maximum possible bilateral exchange and price spread on the Austria-Hungary bidding zone border at 19:00 CET/CEST – 2024 (MW and EUR/MWh)

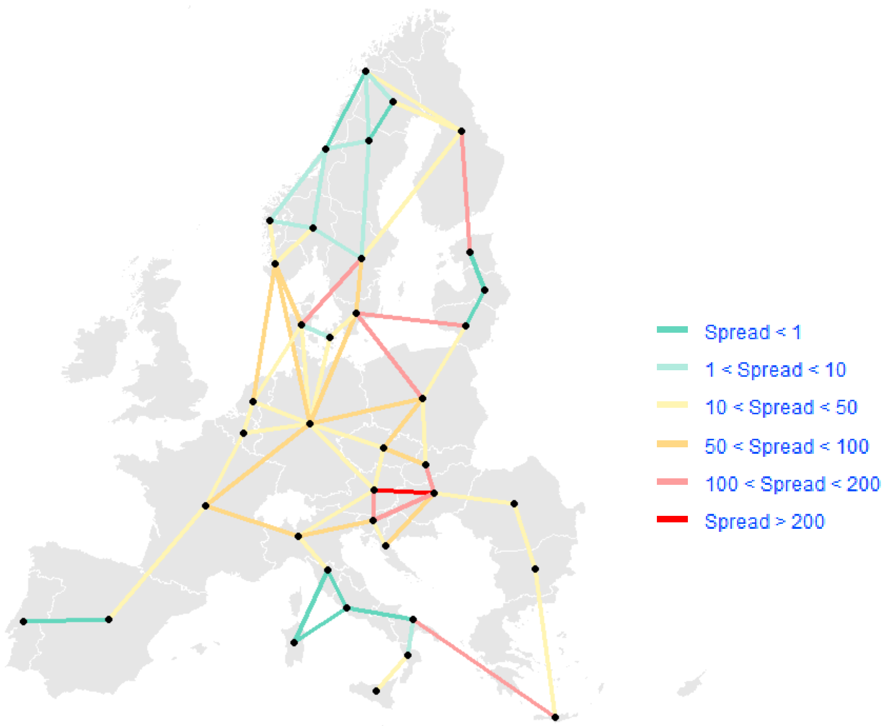


Source: ACER calculation based on JAO Publication Tool and ENTSO-E Transparency Platform data.

Note: Maximum possible bilateral exchange is based on the MaxBex indicator, which is calculated under the assumption that no other cross-zonal exchanges are present in the Core CCR.

The combination of tight local supply-demand conditions and limited cross-zonal capacity contributed to severe price spreads during the evening hours in the bidding zone borders connecting Southeast Europe with the rest of the EU. This is particularly visible for the northern bidding zone borders of Hungary, and the border between Italy and Greece, as highlighted in Figure 11. These high spreads during the evening hours between Southeast Europe and the rest of the EU were sustained during the entire summer.

Figure 11: Average price spreads in the single day-ahead coupling during peak hours of the summer of 2024 - July to September 2024 at 19:00 and 20:00 CEST



Source: ACER calculation based on ENTSO-E Transparency Platform.

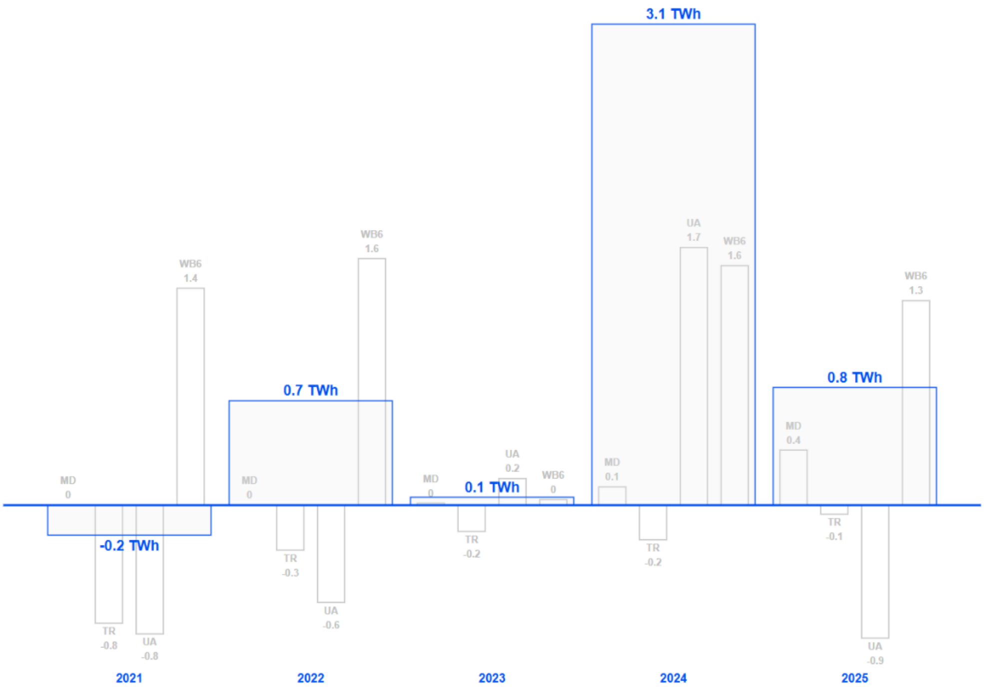
1.4.2. Exchanges with non-EU countries

EU Member States in Southeast Europe also exchange electricity with non-EU countries, most notably the Western Balkans (WB6) and Ukraine, and, to a lesser extent, Moldova and Turkey. These exchanges are supported by the explicit allocation of cross-zonal capacity through auctions organised by the relevant TSOs.

During the summer of 2024, significant cross-border electricity exchanges were observed from EU Member States in Southeast Europe to Ukraine and the Western Balkans. As a result, the EU recorded a net export position of more than 3 TWh over that period, as shown in Figure 12. In particular, the EU's net balance with Ukraine shifted from a predominantly importing position in previous years to sustained exports during the summer of 2024, reflecting increased Ukrainian needs.

Overall, sustained exports to Ukraine and, to a lesser extent, to the Western Balkans increased net demand in the exporting EU Member States. This amplified price pressures during peak hours and contributed to the price formation observed in Southeast Europe during the summer months of 2024. By contrast, in the summer of 2025, exchanges with Ukraine were more balanced, with more frequent two-way flows and an overall net import position, while exchanges with the Western Balkans remained broadly similar to those observed in 2024.

Figure 12: Day-ahead net cross-zonal exchanges between the EU and UA, WB6, TR and MD during summer months - July to September 2021 to 2025 (TWh)



Source: ACER calculation based on ENTSO-E Transparency Platform data.

Note: WB6 correspond to the six non-EU countries of the Western Balkans: Albania, Bosnia and Herzegovina, Kosovo, Montenegro, North Macedonia, and Serbia.

2. Targeted proposals to increase cross-zonal capacity

As discussed above, while cross-border trade contributed to mitigating the regional system stress experienced in Southeast Europe during the summer of 2024, the capacity available on network elements in Central Europe, as well as on the HVDC interconnection between Greece and Italy, was not sufficient to prevent the occurrence of significant price spikes across the region. Greater availability of cross-zonal capacity on specific network elements would have enabled additional imports into the region, thereby reducing prices in Southeast Europe and narrowing the price spreads with the rest of the EU.

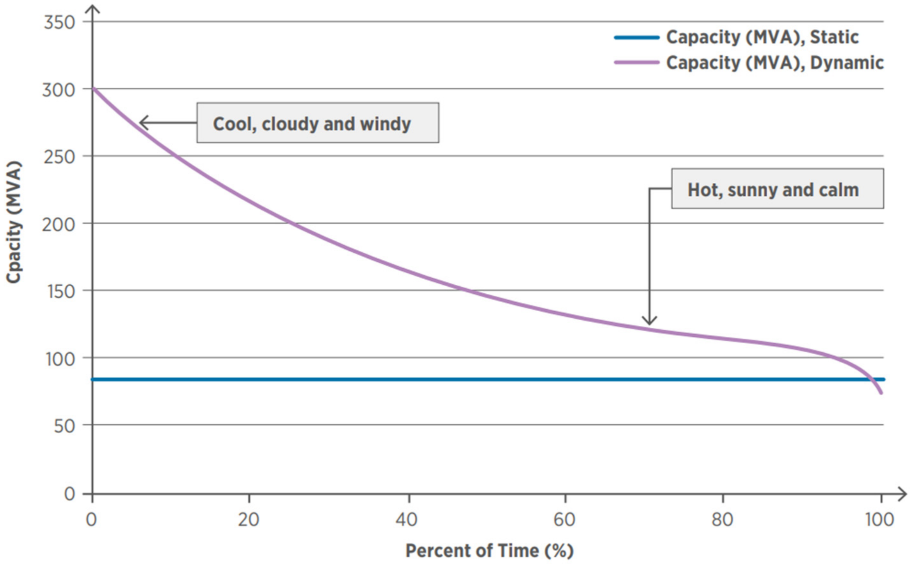
This second section sets out several targeted measures aimed at improving the operational processes and network infrastructure that affect cross-zonal trade within Southeast Europe, as well as between Southeast Europe and the rest of the EU. If implemented, these measures could increase cross-zonal capacity in the short to medium term and improve the ability of imports from the rest of the EU to alleviate prices in Southeast Europe.

2.1. Wider introduction of dynamic line rating in capacity calculation

Power line ratings, which define the amount of electricity that a given line can accommodate, have been traditionally static. This means that they define a single limit for the entire year, based on conservative assumptions and worst-case operating conditions. This approach generally ensures secure system operation, but it may also underestimate the actual transmission capability of a line under more favourable operating conditions. In particular, lower ambient temperatures and higher wind speeds can allow TSOs to increase the ampacity of overhead lines, without compromising grid security.

By allowing the ampacity of existing lines to be adjusted dynamically based on ambient conditions, dynamic line rating (DLR) can improve the utilisation of the existing network infrastructure. This may in turn support higher cross-zonal capacities and facilitate additional cross-zonal trade, thereby complementing the need for investment in new transmission lines. The comparison between dynamic and static line rating is exemplified in Figure 13.

Figure 13: Exemplary figure on the functioning of dynamic line rating, compared to that of static line rating



Source: IRENA elaboration

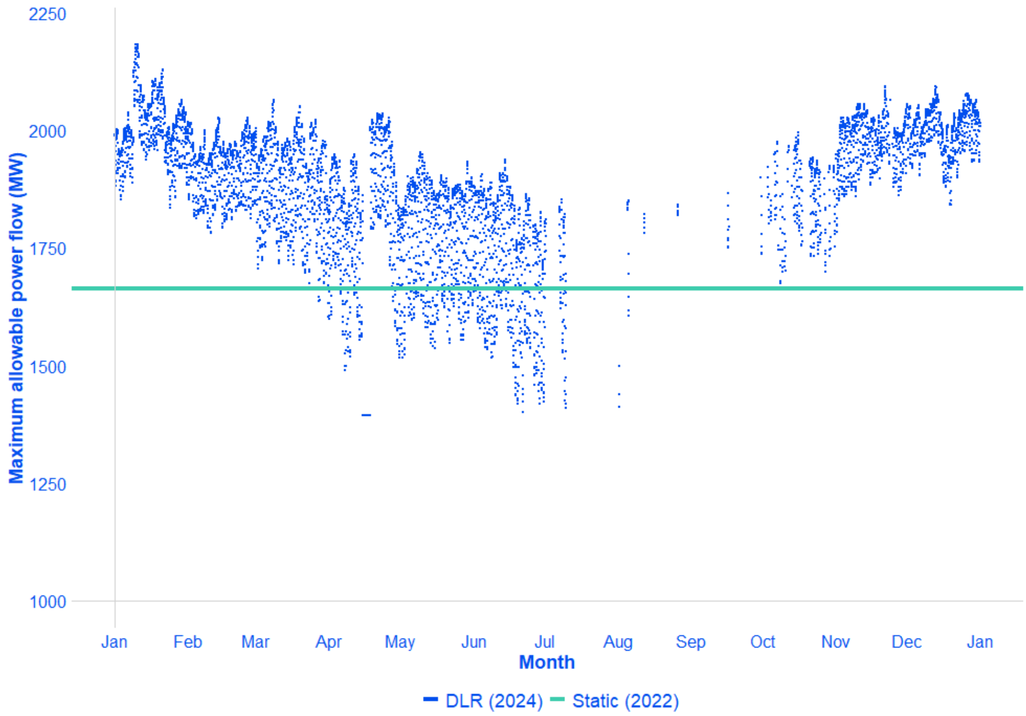
It is important to note that DLR does not only lead to higher line ratings, and thus more electricity flows through a given network element. In some cases, ambient conditions may be worse than those assumed when defining static ratings and thereby imply lower ampacity values, which result in reduced cross-zonal trade. While this may indeed constrain electricity exchanges, compared to the static alternative, it will also enhance operational security by ensuring that transmission limits continue to reflect actual system conditions.

To effectively contribute to increased cross-zonal trade, dynamic ratings need to be properly reflected in capacity calculation. This requires forecasting relevant meteorological conditions along the full length of the power lines, typically up to two days ahead, so that updated line ratings can be taken into account in capacity calculation inputs.

Past implementation in the Core region can provide a useful indication of the potential from integrating DLR into capacity calculation. One such example is the network element '*Hradec - Mírovka*', operated by ČEPS, which transitioned from a fully static rating in 2022 to highly dynamic rating in 2024. This is shown in Figure 14.

This transition led to an increase in the available transmission capacity of the line for most market time units of the year. Concretely, the maximum admissible flow (or Fmax) was higher in 90% of available MTUs, while the average increase in Fmax amounted to 13%. At its maximum, the increase in Fmax reached 31.2%. These results illustrate the significant potential of DLR to unlock additional transmission capacity where weather conditions are more favourable than those assumed under static ratings. This example also shows that fixed ratings may, in certain situations, overestimate the actual ampacity of a line. This appears to occur mainly during specific hours in the summer months, when ambient conditions are less favourable than those considered when defining the static rating.

Figure 14: Example of implementation of dynamic line rating in capacity calculation on network element *'Hradec - Mirovka'* – 2022 and 2024 (MW)



Source: ACER calculation based on JAO Publication Tool data.

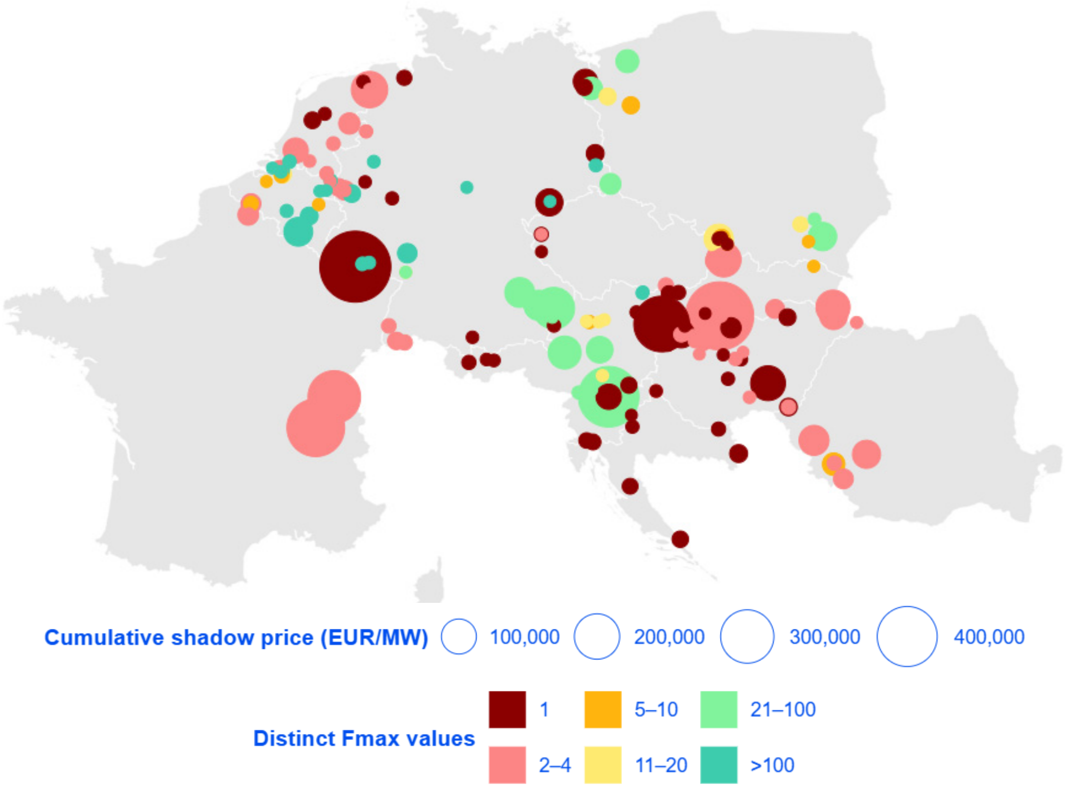
Note: Periods in 2024 with no observations correspond to the power line undergoing maintenance or not fulfilling the relevance threshold defined in capacity calculation.

As observed above, the Fmax values reported as part of the Core capacity calculation process can be used to infer to which extent DLR is applied by each Core TSO at the level of individual network elements. Figure 15 categorises the rating of critical network elements in Core flow-based market coupling that were significantly congested during 2024. As an example, the presence of four or fewer different Fmax values over the year may indicate the use of fully static or, at most, seasonal ratings. These cases are represented in red.

Critical network elements associated with high cumulative shadow prices are likely to offer the greatest potential benefits from the introduction of DLR in capacity calculation, provided that such introduction does lead to a net increase in capacity during congested periods. On congested network elements, the expected market gains from increasing transmission capacity are more likely to outweigh the costs of implementation. In Figure 15, larger red circles indicate network elements with fully static or seasonal ratings that significantly constrained cross-zonal trade in 2024, and where additional capacity could have enabled more cross-zonal trade.

In addition, ACER noticed that TSOs operating cross-border network elements often do not apply the same rating approach to both sections of the line. This is observed in cases where one side of the cross-border line used highly dynamic ratings, the other uses static ratings. In these cases, the more restrictive section of the cross-border line may become binding, limiting the overall capacity made available to the market and reducing the benefits of applying higher ratings on the neighbouring section.

Figure 15: Usage of dynamic line rating in Core capacity calculation on network elements limiting cross-zonal trade - 2024 (EUR/MW)



Source: ACER calculation based on JAO Publication Tool data.

Figure 16 shows an overview of the operational practices regarding line rating followed by the different Core TSOs on their critical network elements. The TSO-level overview shows that, in 2024, a large share of CNEs within the Core CCR were modelled using at most seasonal ratings. In fact, six Core TSOs modelled virtually all of their network elements in capacity calculation under these ratings, with a considerable number of network elements using a single value of Fmax throughout the year. By contrast, Amprion, 50Hertz, Elia and ČEPS appear to show the broadest deployment of highly dynamic ratings in capacity calculation among Core TSOs.

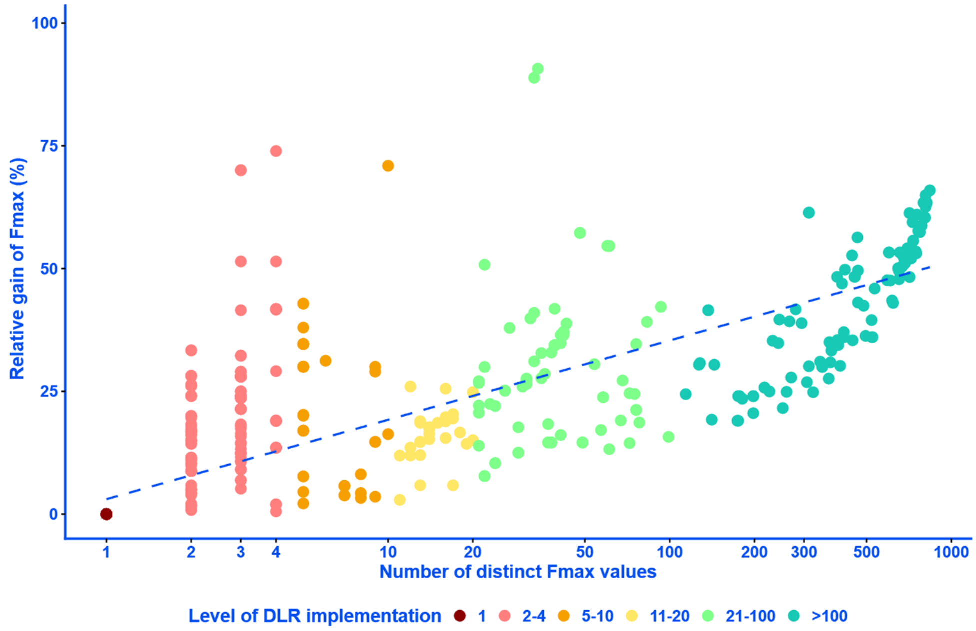
Figure 16: Overview of dynamic line rating use in capacity calculation per Core TSO - 2024 (% of CNEs)

Distinct Fmax values	≤4	5–10	11–20	21–100	≥100
AT	63.8%	1.7%	5.2%	26.7%	2.6%
BE	6.9%	58.6%	3.4%	0.0%	31.0%
CZ	72.5%	0.0%	0.0%	11.8%	15.7%
DE - 50Hertz	89.7%	0.0%	0.0%	0.0%	10.3%
DE - Amprion	45.1%	0.0%	2.9%	4.6%	47.4%
DE - TenneT	62.7%	1.7%	6.8%	25.4%	3.4%
DE - TransnetBW	45.1%	9.8%	21.6%	21.6%	2.0%
FR	100.0%	0.0%	0.0%	0.0%	0.0%
HR	100.0%	0.0%	0.0%	0.0%	0.0%
HU	98.5%	1.5%	0.0%	0.0%	0.0%
NL	89.3%	0.0%	0.0%	3.6%	7.1%
PL	19.6%	26.1%	21.7%	32.6%	0.0%
RO	98.1%	1.9%	0.0%	0.0%	0.0%
SI	100.0%	0.0%	0.0%	0.0%	0.0%
SK	100.0%	0.0%	0.0%	0.0%	0.0%

Source: ACER calculation based on JAO Publication Tool data.

Experience from the Core capacity calculation process shows that the network elements with highly dynamic ratings generally exhibit significantly greater increases in Fmax than those modelled using seasonal or otherwise less dynamic ratings. The most positive cases of DLR implementation in the Core region, corresponding to Amprion and ČEPS, show a difference between the lowest and highest value of Fmax in a year that exceeds 50%. This difference is highlighted in Figure 17, for all network elements in the region.

Figure 17: Comparison between number of distinct Fmax values (logarithmic scale) and relative difference between the lowest and highest Fmax value, per Core CNE - 2025 (%)

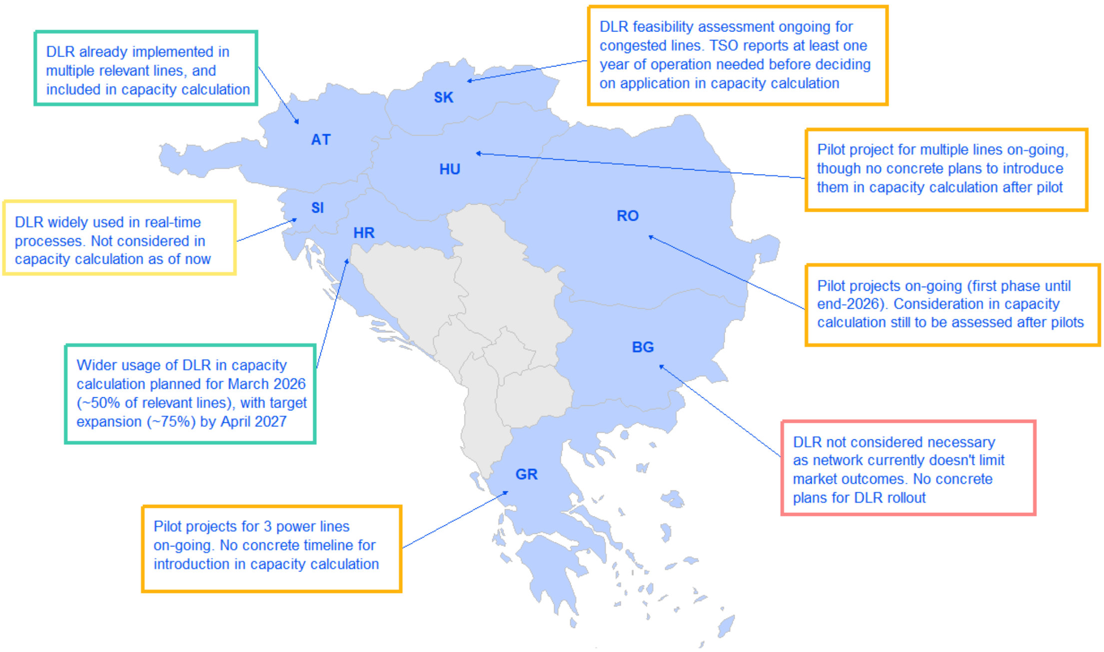


Source: ACER calculation based on JAO Publication Tool data.

As observed in the Figure 17, even among the network elements modelled with several pre-defined ratings over the year, there are substantial differences in the way such ratings are defined. Determining Fmax for specific periods of the year based on a probabilistic assessment of historical conditions can already deliver significant gains compared with applying a single Fmax value throughout the year.

The roll-out of DLR in real-time processes and its consideration in capacity calculation is uneven across the EU, with some TSOs already forecasting ambient conditions in most of their network elements, and some others still relying on fully fixed ratings. In the context of this assessment, ACER summarised the level of implementation of DLR in Southeast Europe as highlighted in Figure 18.

Figure 18: ACER assessment of the level of implementation of dynamic line rating in the evaluated area



Source: Information reported by TSOs in the context of this assessment.

Considering the potential benefits of monitoring power line conditions, both in terms of increased cross-zonal trade and enhanced system security, ACER proposes the following measures to accelerate the uptake of DLR in Central and Southeast Europe:

1. TSOs to prioritise the implementation of DLR on highly congested network elements within the evaluated region, where potential benefits outweigh implementation costs;
2. TSOs to make sure that the use of DLR is reflected as such in capacity calculation inputs as soon as possible after it is implemented in real-time processes, with due consideration for the uncertainty introduced by forecasts of ambient conditions;
3. In the meantime, TSOs to assess whether the granularity of line ratings can be increased for network elements that currently rely on static or seasonal ratings in capacity calculation, such as:
    - by introducing seasonal ratings for network elements with a fixed yearly rating, or;
    - by increasing the number of ratings based on probabilistic assessments of ambient conditions;
4. TSOs to ensure that the deployment of DLR is sufficiently coordinated on both sections of cross-border lines, so that its benefits are not limited by static ratings applied by the neighbouring TSO;
5. Policymakers to consider introducing a harmonised EU-level requirement to ensure the deployment of DLR on network elements often limiting cross-border trade, subject to a positive cost-benefit analysis.

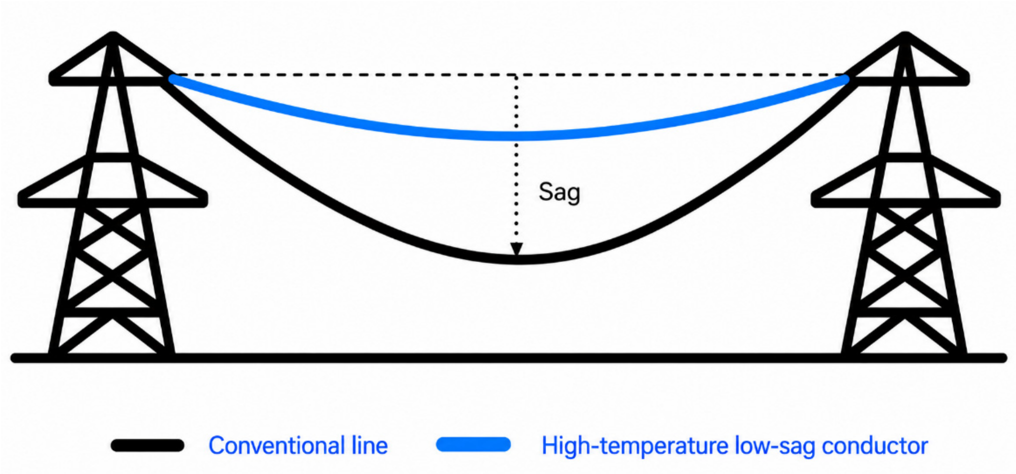
2.2. Upgrading of standard power lines with high-temperature low-sag conductors

Conventional overhead line conductors are typically designed to operate within relatively limited temperature ranges, as higher conductor temperatures lead to thermal expansion and therefore increased sag. When the conductor heats up under higher current flows or warmer ambient conditions, it elongates and hangs lower between towers, reducing the distance to the ground, and constraining the maximum transferable power.

Replacing existing overhead line conductors with high-temperature low-sag (HTLS) technologies enables operation of the line at higher temperatures while maintaining sag within acceptable limits. This uprating can typically increase conductor ampacity by 50 to 100%, depending on the technology and operating conditions. The comparison between standard and HTLS conductors is exemplified in Figure 19.

Reusing existing towers and rights-of-way generally allows for faster deployment and lower investment costs compared to the construction of new lines. Nonetheless, TSOs indicate that reinforcement of pylons and/or upgrades to adjacent substations may be required, potentially extending project timelines and increasing costs. TSOs also need to assess permitting requirements for each reconductoring project, including any reinforcement works on pylons and substations.

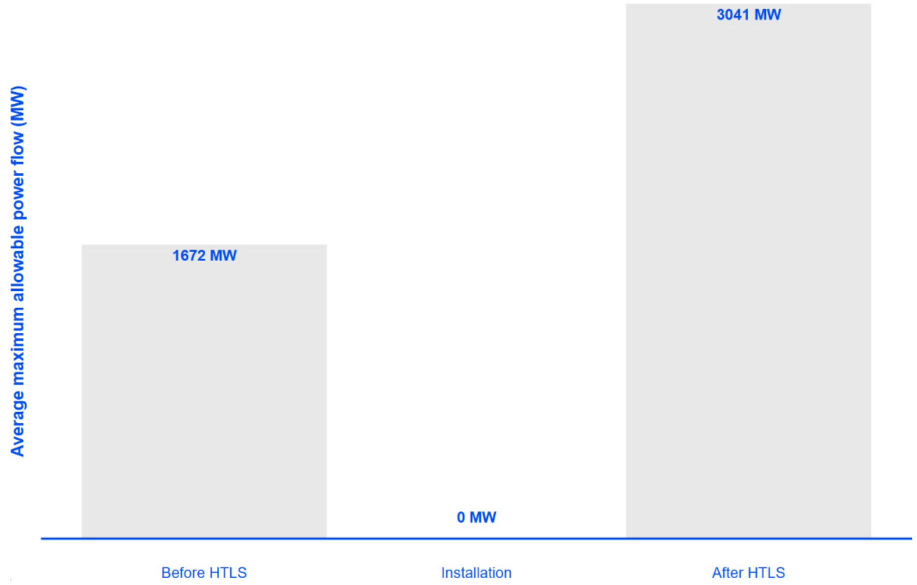
Figure 19: Exemplary figure on the functioning of high-temperature low-sag conductors, compared to that of conventional conductors under the same loading



Source: ACER elaboration.

Some EU TSOs, such as Elia, have extensive experience with conductor replacement projects and with reflecting the resulting technical parameters in capacity calculation processes. The example in Figure 20 shows the upgrade of cross-border line *'Avelgem - Avelin'* between Belgium and France, which took place in 2022, and resulted in an increase in the maximum allowable power flow of over 80%, allowing for significantly more cross-zonal trade through this network element.

Figure 20: Impact on average Fmax of upgrading the conductor of cross-border line between Belgium and France '*Avelgem - Avelin*' – 2022 (MW)

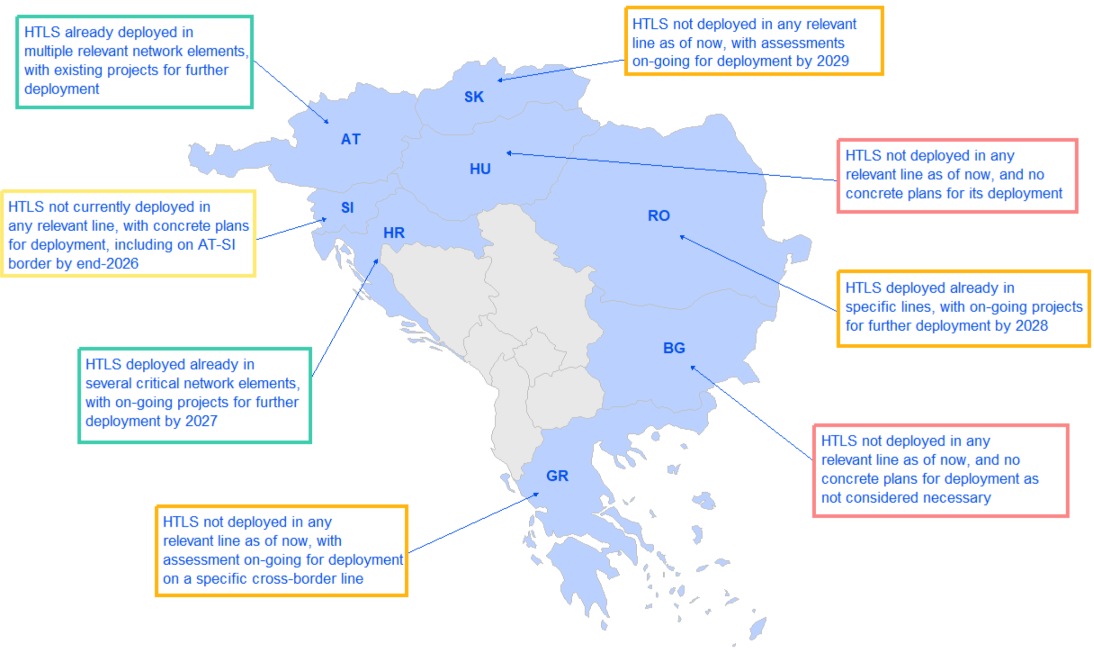


Source: ACER calculation based on JAO Publication Tool data.

Given the potential market and operational impact of taking the line out of operation during the construction works, conductor replacement projects require significant planning and regional coordination. In the case of the reconductoring of the *'Avelgem - Avelin'* power line, the upgrade required the network element to be unavailable for approximately three months in order to complete the project, following an extensive planning phase. During the replacement period, no cross-zonal capacity was made available on this network element.

The upgrading of standard conductors with HTLS alternatives has thus far been mostly limited to specific Member States. In the context of this assessment, ACER summarised the level of implementation of HTLS conductors in the evaluated area as presented in Figure 21.

Figure 21: ACER assessment of the level of implementation of high-temperature low-sag conductors in the evaluated area



Source: Information reported by TSOs in the context of this assessment.

Considering the significant potential of HTLS conductors to increase network capacity faster and at a lower cost than by building new power lines, ACER proposes the following measures to increase network capacity in Central and Southeast Europe:

1. TSOs to systematically assess the feasibility of upgrading traditional power lines with HTLS or similar technologies, prioritising those power lines most often restricting trade.
2. TSOs to ensure that upgraded conductor characteristics are promptly reflected in capacity calculation processes, once the project is completed.
3. TSOs to assess the feasibility of combining HTLS conductors and DLR on priority corridors, to maximise available capacity while maintaining grid security.

2.3. Finalising the implementation of the minimum 70% requirement

In the EU, the main regulatory tool to ensure the maximisation of cross-zonal capacities is the 70% requirement, introduced in the Electricity Regulation. It requires TSOs to offer at least 70% of their physical capacity on all relevant lines for cross-zonal trade, while complying with safety standards of secure network operation. This requirement was introduced to address the discrimination of cross-zonal exchanges in favour of intra-zonal exchanges, inherent to a zonal market design.

To fulfil the 70% requirement without endangering system security, EU Member States could opt for a transitional period i.e. action plan, to address structural congestion in the power grid while gradually implementing the requirement until the end of 2025. In parallel, TSOs could also be granted yearly derogations by their NRA wherever the 70% requirement or transitional targets would prevent TSOs from maintaining operational security. The 70% requirement is currently being implemented by EU TSOs, with uneven progress across the EU.

Figure 22: Average level of implementation of the 70% requirement in the Core CCR per Member State, considering flows induced by third-country exchanges – 2022 to 2024 (% of Fmax)

Source: ACER 2025 Monitoring Report on cross-zonal capacities and congestion management.

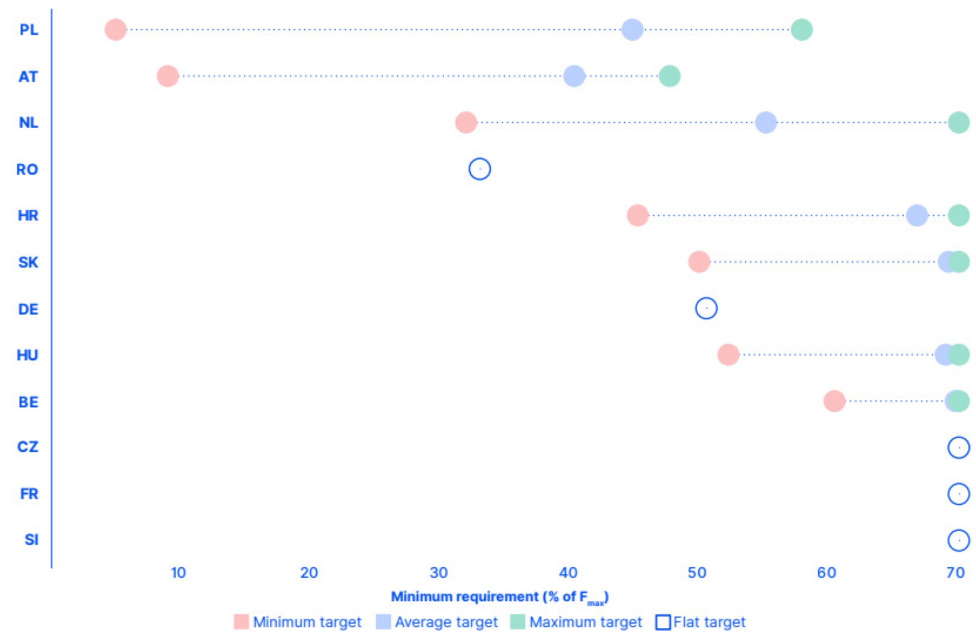
ACER monitors yearly the progress in implementing the minimum 70% requirement in the EU. The latest ACER Monitoring Report on cross-zonal capacities was published in September of 2025 and assesses data from 2024. This average level of implementation of the 70% requirement in the Core CCR is shown in Figure 22[3].

In six Member States in the Core CCR, derogations have been granted yearly, with most citing the presence of excessive loop flows[4] and the lack of a coordinated congestion management framework as the main reason. Derogations applicable in Austria, Belgium, the Netherlands and Poland detail a methodology to adjust the applicable targets to account for excessive loop flows. Such a methodology, along with the threshold for excessive loop flows, are provided in the derogation request which is approved by the relevant NRA.

In the derogations of these four systems, the level of acceptable loop flows is currently defined as 20% for cross-zonal network elements, as no internal flows are present on such lines and another 10% is reserved as reliability margin. For internal network elements, on the other hand, the TSOs in Austria and Poland define a maximum level of 2%, while those from Belgium and the Netherlands allow for loop flows up to 10%. Any forecasted loop flows above such levels are deducted from the minimum 70% requirement.

The derogations of Slovakia and Romania introduced a single requirement, covering all CNECs and MTUs, regardless of forecasted conditions such as the expected non-allocated flows and local remedial action potential. Figure 23 shows the average requirements applicable on the network elements of all Core TSOs in 2024.

Figure 23: Minimum requirements for cross-zonal trade in the Core CCR per Member State – 2024 (% of Fmax)



Source: ACER 2025 Monitoring Report on cross-zonal capacities and congestion management.

In the South-East Europe (SEE) CCR, derogations are applicable in Romania and Greece and both based on fixed targets applicable to all CNECs. The targets applicable in 2024 in Romania and Greece were 41% and 60%, respectively.

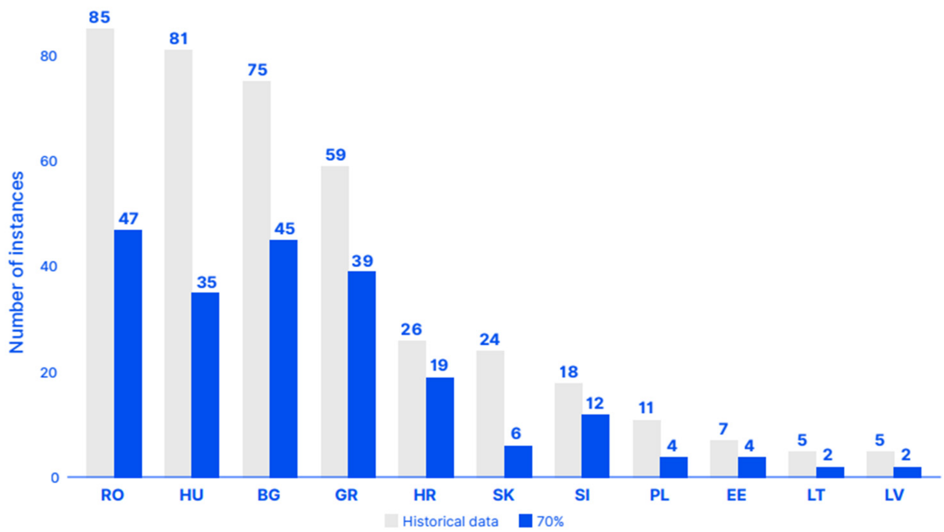
The ACER 2025 monitoring report on cross-zonal capacities indicated that higher fulfilment of the 70% requirement in 2024 would have mitigated the price spikes observed in Southeast Europe to a significant extent, under the simplified assumptions used in this counterfactual analysis. This is because it would have allowed for additional cross-zonal trading possibilities in the network elements that

[3] In 2024, all but three Member States in the Core CCR (France, Slovenia and Czechia) were bound by interim requirements lower than 70%, due to applicable Action Plans and derogations.

[4] Flows induced in the network of a given bidding zone by internal trading in a different bidding zone.

prevented additional trade during the summer of 2024. This was assessed by simulating market coupling conditions under higher availability of cross-zonal capacity[5], and the results are summarised in Figure 24.

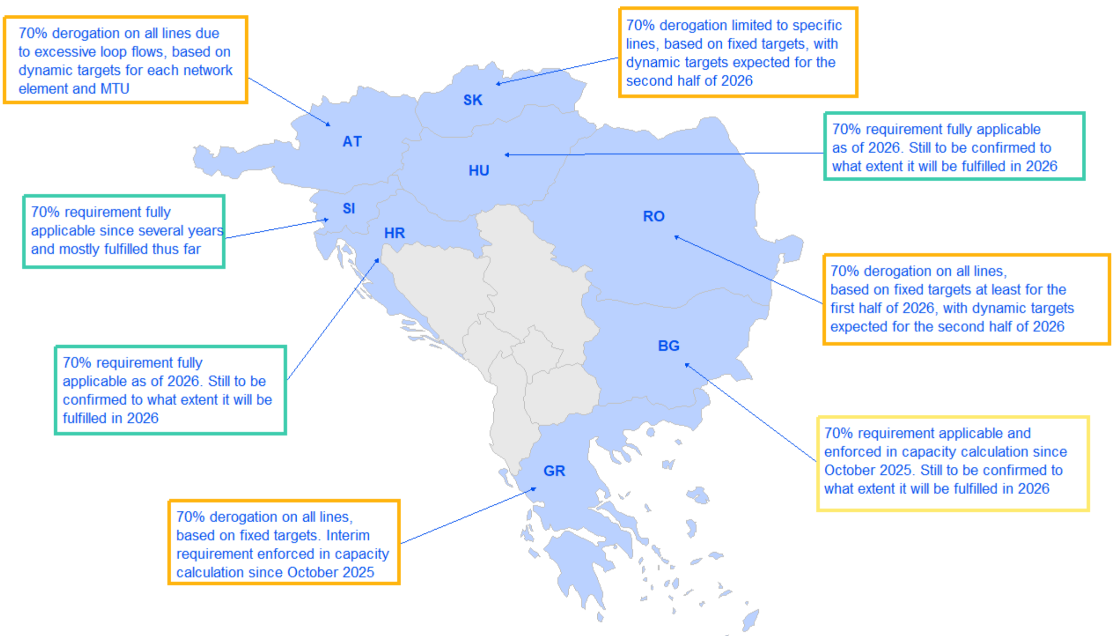
Figure 24: Count of instances of day-ahead prices above 400 EUR/MWh in select EU bidding zones, compared with the counterfactual analysis – July to September 2024 (number of instances)



Source: ACER 2025 Monitoring Report on cross-zonal capacities and congestion management.

At the time of drafting this assessment, the monitoring results on the implementation of the minimum 70% requirement for year 2025 were still not available. In the context of this assessment, ACER summarised the level of implementation of the 70% requirement in the evaluated area as presented in Figure 25.

Figure 25: ACER assessment of the level of implementation of the minimum 70% requirement in the evaluated area



Source: Assessment performed by ACER based on 70% monitoring.

[5] Simplified assumptions were used for such a simulation. More details can be consulted in the ACER 2025 Monitoring Report on cross-zonal capacities and congestion management.

Considering the demonstrated impact of finalising the 70% requirement in mitigating price spikes across the EU, and particularly in Southeast Europe, ACER proposes the following measures to increase the margins of capacity made available in Central and Southeast Europe:

1. All TSOs with fixed derogations to ensure that derogations define applicable targets dynamically per hour and CNEC, so that at least all internal flows and the acceptable level of loop flows are tested against TSOs' remedial action potential[6].
2. TSOs to ensure that any dynamic derogation defines an absolute minimum requirement, as is already the case for the relevant Core TSOs.
3. In the longer term, Core TSOs to avoid derogations based on loop flows, by prioritizing the implementation of a functioning ROSC with associated cost sharing that ensures adequate and fair mitigation of excessive loop flows.
4. In the near term, Austrian and Polish TSOs to assess whether the share of acceptable loop flows on internal network elements could be increased without compromising system security[7].
5. TSOs to make best efforts to maximise cross-zonal capacities made available to the intraday market, with due consideration to the more limited availability of remedial actions close-to-real-time.

2.4. Wider usage of curative remedial actions in capacity calculation

TSOs may use phase-shifting transformers (PSTs) and topological remedial actions to optimise power flows across the network. PSTs are devices that help direct electricity flows away from congested lines and towards less loaded parts of the network. Topological remedial actions consist of temporary changes to the network configuration, such as switching certain network elements on or off, in order to reroute flows and reduce congestion.

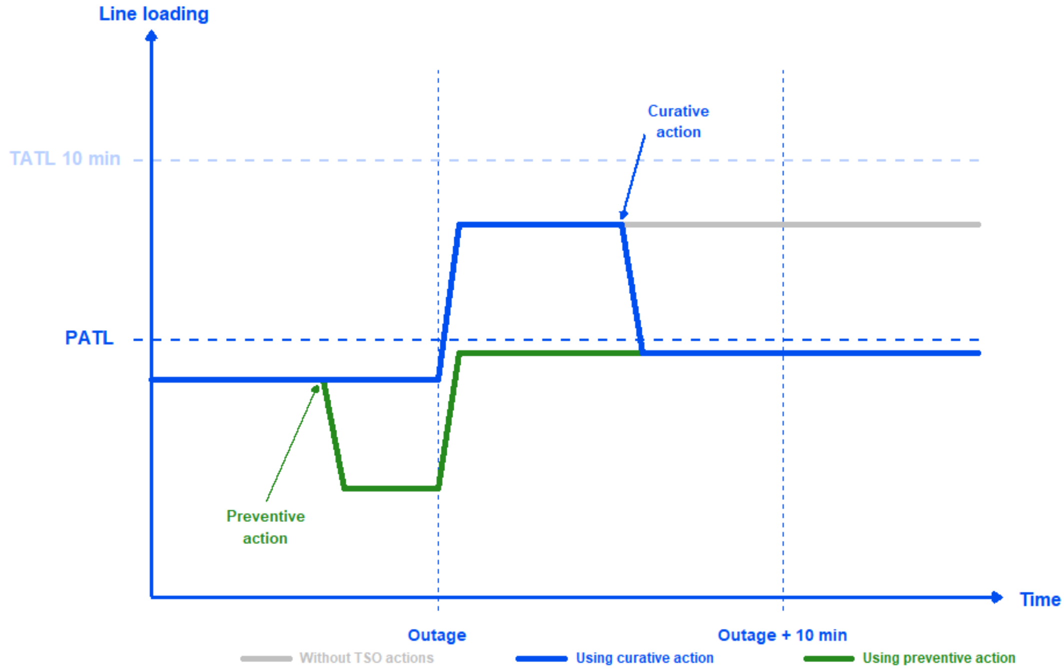
These non-costly remedial actions may be used preventively or curatively. Preventive actions are activated in advance of an N-1 outage, when such outage is forecasted to create a violation of security limits in another network element, so that flows remain below the maximum admissible limit under contingency conditions. Curative actions, on the other hand, are activated only if the outage occurs, immediately after, allowing for a controlled temporary overload until the remedial action is triggered by the TSO. The comparison between the two types of remedial actions is illustrated in Figure 26.

The safe use of curative remedial actions in system operation requires efficient operational processes and a high degree of coordination between neighbouring TSOs. Because curative actions must be triggered within minutes after an outage, TSOs need to forecast in advance both the expected security violations and the sequence of remedial actions required to address them. Moreover, in order for curative remedial actions to be considered in capacity calculation, their availability must be reliably known already two days ahead of delivery.

[6] Whenever such remedial action potential is insufficient to secure the calculated capacities, the TSO is to reduce capacities accordingly via validation.

[7] These two TSOs currently only allow, as per the approved derogations, up to 2% of physical capacity on internal network elements for the purpose of loop flows, with any forecasted loop flows surpassing that threshold directly reducing the 70% requirement.

Figure 26: Exemplary figure on the functioning of curative remedial actions, compared to that of preventive remedial actions



Source: ACER elaboration.

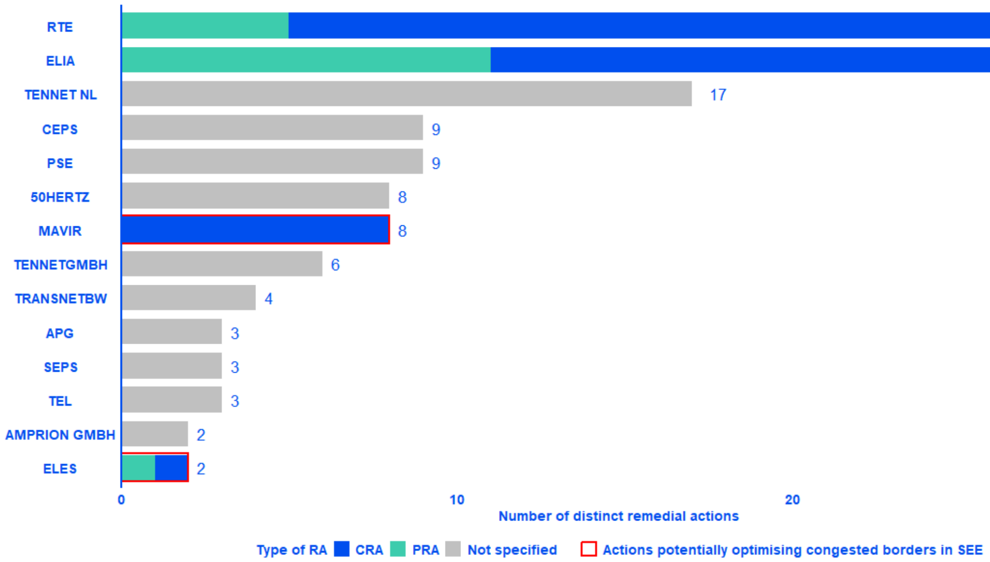
Note: 'TATL 10 min' stands for a thermal limit that is admissible only for a maximum of 10 minutes.

When curative actions are included in capacity calculation, they allow TSOs to increase the thermal rating of critical network elements up to a temporary admissible thermal limit (or TATL). If the curative action can reduce the flow on the critical network element back below its permanent admissible thermal limit (PATL) after the outage, the temporary limit can support higher cross-zonal capacity. Should the curative action not be effective, then the permanent limit will define the available capacity of the network element.

In the Core capacity calculation process, there is a dedicated process to optimise the usage of non-costly remedial actions, both curatively and preventively. This is the non-costly remedial action optimisation (NRAO). Since preventive actions need to be implemented in the base case, meaning before any contingency takes place, their optimisation needs to be global and consider all critical network elements in the region. On the other hand, the optimisation of curative actions can be local, as a given action will only affect those critical network elements that share a contingency.

All non-costly remedial actions enabled by Core TSOs in the NRAO, both for curative and/or preventive use, are listed by Core TSOs in the Static Grid Model. As observed in Figure 27, this data confirms that almost all Core TSOs, with the exception of HOPS, have some degree of availability of topological remedial actions or PSTs. Nonetheless, these actions may not always be available in the daily Core capacity calculation process, such as in the case of outages or specific substation topologies, and most TSOs will only enable them as preventive actions.

Figure 27: Overview of available non-costly remedial actions in Core capacity calculation per Core TSO based on Core Static Grid Model – 2025



Source: ACER calculation based on Core Static Grid Model.

Note: In grey, all remedial actions where no identifier for curative or preventive is available, and thus no categorisation was possible.

The optimisation of non-costly remedial actions in the Core NRAO is described in the Core capacity calculation methodology. Its objective function is to maximise the 'relative RAM' parameter on the most constraining CNECs based on the cross-zonal exchanges assumed in the grid model. The 'relative RAM' parameter aggregates the available capacity on a given CNEC (i.e. the RAM), together with the sensitivity of such CNEC to cross-zonal exchanges, into a single numeric indicator[8].

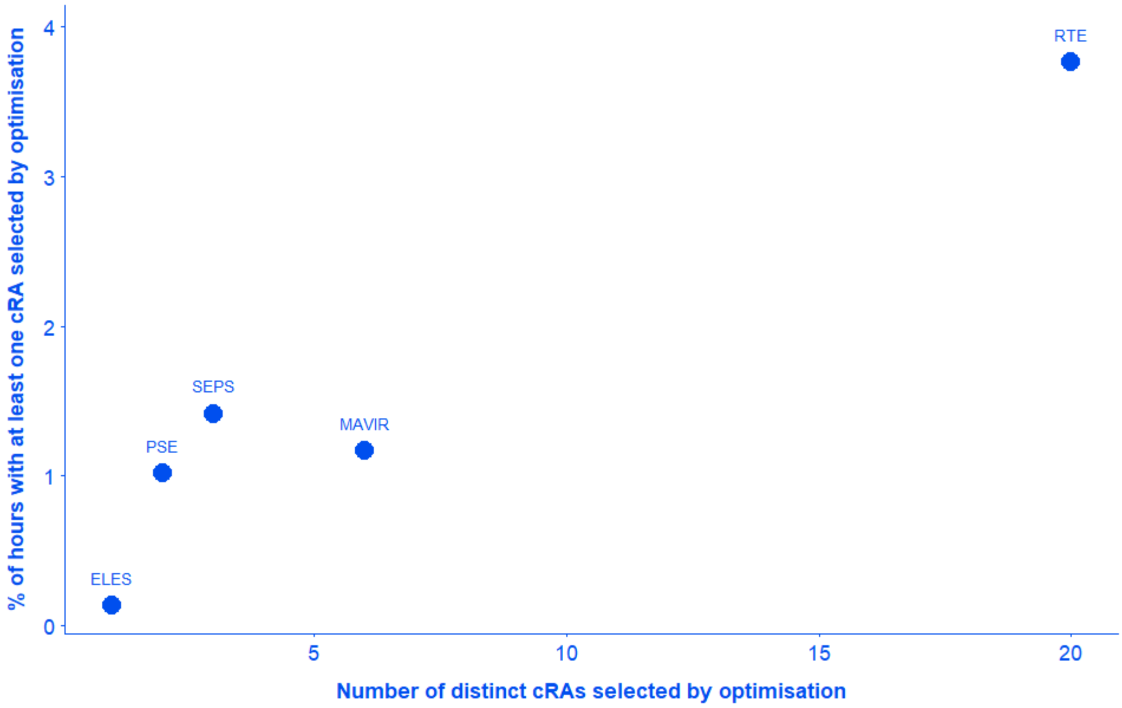
For a non-costly action to be selected by the optimisation, it needs to have a minimum impact on the objective function, meaning that it needs to improve the 'RAM relative' parameter on the most constraining CNEC(s), while respecting several optimisation constraints. The selected non-costly actions must satisfy two main constraints: they must not create or worsen an overload on any network element by more than 50 MW, including elements not considered in capacity calculation; and they must not cause loop flows on any cross-zonal CNEC to exceed a predefined threshold. These conditions should in principle be easier to meet for curative actions than for preventive actions, as these only affect critical network elements that share a contingency.

However, the current optimisation approach results in very few of the available curative remedial actions being selected by the optimisation, either due to no positive impact on the objective function or for violating any of the optimisation constraints. Moreover, the current process seems to focus only the most congested lines under the exchanges assumed in the CGM and does not systematically assess all possible combinations of curative remedial actions and contingencies. However, since the effect of curative actions is independent between CNECs that don't share a contingency, in principle all combinations of contingencies and curative remedial actions could be tested by the NRAO.

[8] Relative RAM is calculated as per the Core capacity calculation methodology, dividing the RAM of a given network element by the sum of positive zone-to-zone PTDFs.

Figure 28 presents the percentage of hours where the existing optimisation has selected a curative remedial action of each Core TSO over a three-year period, showing that curative actions are only actually used on up to 4% of market time units.

Figure 28: Overview of activation of curative remedial actions in the Core capacity calculation process per Core TSO – 2023 to 2025

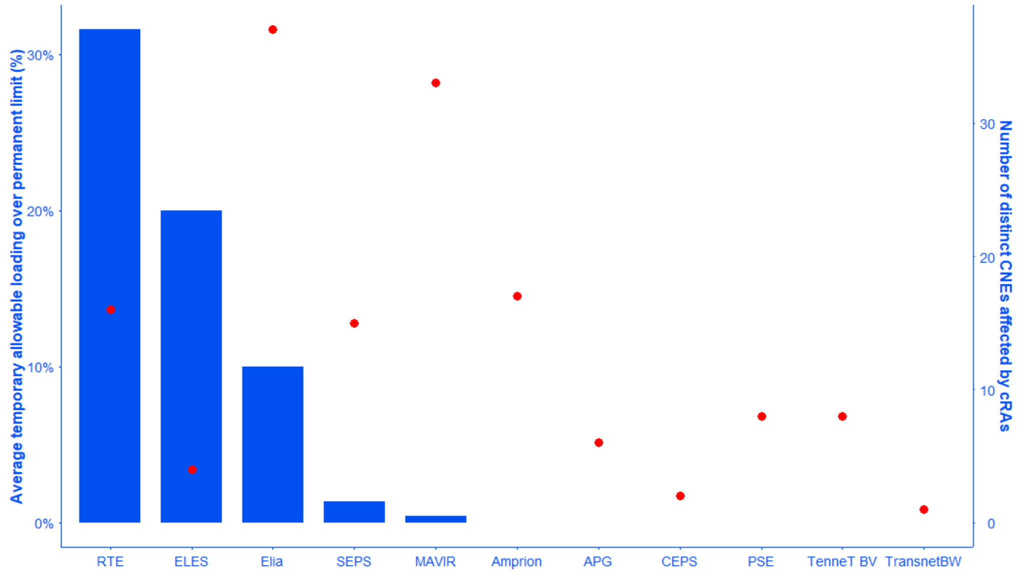


Source: ACER calculation based on JAO Publication Tool.

As anticipated above, TSOs need to define temporary limits (TATLs) on specific network elements to enable the use of curative actions, so that a controlled temporary overload is permitted until the curative action can be triggered. These temporary limits are only allowable provided that a curative remedial action can reduce the flow back within the permanent limit, once the contingency takes place. Figure 29 shows the average temporary limits defined by each Core TSO on their network elements, as a percentage increase over the permanent limits.

As highlighted in the Figure 29, only three TSOs define meaningful temporary limits, with RTE making the widest use. By contrast, most Core TSOs do not define temporary limits at all, or do so to a negligible extent, making curative actions entirely ineffective on their network elements. It is important to note that, when the most constraining network elements in capacity calculation (i.e. those that the NRAO will try to decongest) do not have temporary limits defined, the optimisation will most likely not be able to find any beneficial curative action.

Figure 29: Average allowable temporary increase of Fmax and number of CNEs affected by curative remedial actions per Core TSO – 2025 (% over permanent thermal limit)

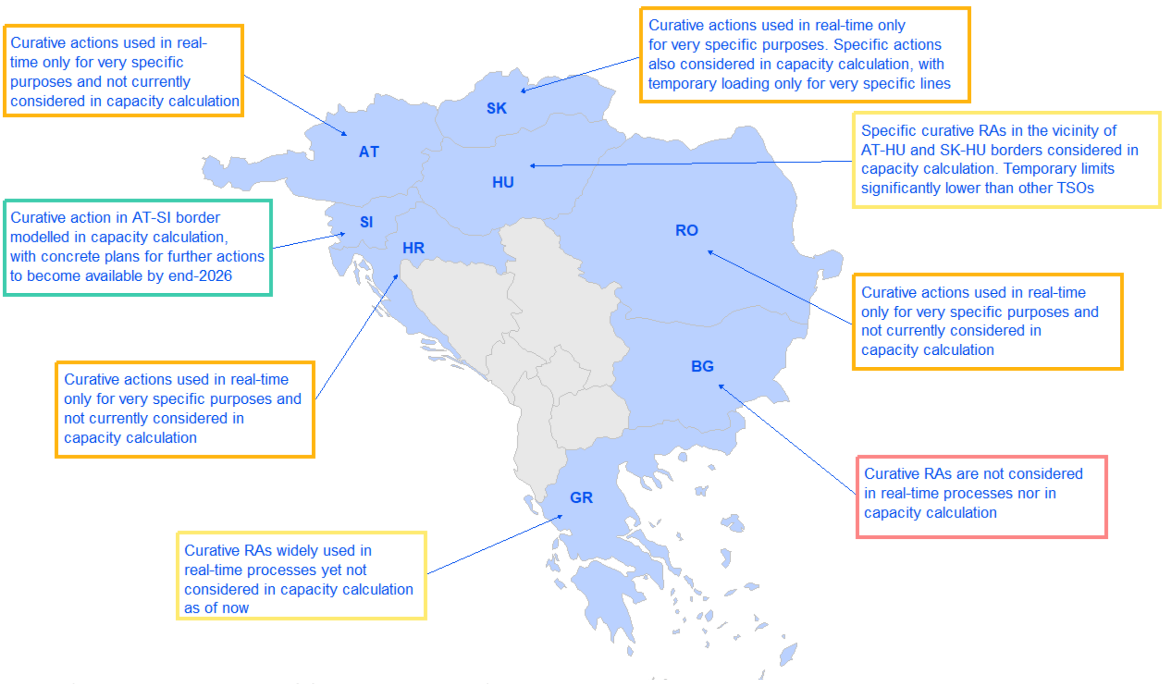


Source: ACER calculation based on JAO Publication Tool.

TSOs may, in principle, allow for temporary limits on their network elements even when they don't define any curative remedial action themselves. This will allow for remedial actions defined by neighbouring TSOs to potentially decongest their network elements, enabling more actions to be selected by the optimisation.

In summary, the consideration of curative remedial actions in capacity calculation in the Core CCR is limited to only a few TSOs, such as those of France, Belgium or Slovenia. Even for such TSOs, the design of the remedial action optimisation results in these actions being very rarely used. However, this practice is significantly more common in the South-West Europe or the Nordic CCRs. With regard to the evaluated area, ACER summarised the usage of curative remedial actions as presented in Figure 30.

Figure 30: ACER assessment of the level of usage of curative remedial actions in the evaluated area



Source: Information reported by TSOs in the context of this assessment.

The use of curative remedial actions allows for a more efficient way of managing grid congestion that when relying solely on preventive actions, as these can be optimised more locally. Their use, however, must give due consideration to system security, as they depend on the TSO being able to react rapidly following an outage. When appropriately modelled in capacity calculation, curative remedial actions can increase cross-zonal trade over the most congested network elements. In light of this, ACER proposes the following measures to ensure a more effective use of the curative remedial action potential in Central and Southeast Europe:

1. Core TSOs to jointly study the factors behind the observed limited activation of curative remedial actions in the Core capacity calculation process and propose amendments to the current optimisation approach to ensure a more effective solution, as foreseen by the Core capacity calculation methodology.
2. Individual Core TSOs that do not rely on curative actions to assess the possibility of introducing temporary limits on highly congested lines that they operate, so that these lines can be more effectively optimised by curative actions introduced by neighbouring TSOs[9].
3. TSOs regularly relying on curative actions in real-time processes, and for which their availability can be guaranteed at the time of capacity calculation, to consider including such actions in capacity calculation, with due regard for system security.
4. TSOs that do not currently rely on curative remedial actions in their system operation practices to assess the feasibility of revising their operational practices to enable their use.

2.5. Increasing coordination in network modelling between Central and Southeast Europe

Coordinated operational processes, such as capacity calculation and security analysis, rely on power system representations that cover multiple TSO control areas. These representations are captured in the Common Grid Models (CGMs), which are created by merging each TSO's individual representation of its control area, referred to as an Individual Grid Model (IGM), on the basis of a common forecast of expected exchanges between control areas.

Initially, each CCR created and used its own CGM for capacity calculation purposes, typically covering the entire synchronous area in which the region operates. Each CGM is built using the IGMs specifically delivered by participating TSOs for this purpose, together with common forecast of net positions. For the representation of control areas outside the region, less representative models are often used, such as reference models created for day-ahead congestion forecasts.

In the case of the Core and SEE CCRs, both regions model the entire Continental Europe synchronous area for the purpose of capacity calculation. The Core region collects dedicated two-day-ahead individual grid models from Core TSOs and completes them with reference day-ahead models for control areas outside the region, including EU and non-EU control areas in Southeast Europe. Conversely, the SEE CCR relies on dedicated models from SEE TSOs and reference models for areas outside the region. In addition, each region uses its own forecast of exchanges between areas for the whole synchronous area.

Better coordination between the Core and SEE regions in grid modelling can support a more accurate assessment of available network capacity. This will in turn ensure that offered cross-zonal capacity is closely in line with the network possibilities and reduce some of the uncertainty that TSOs need to deal with when calculating capacities.

Core TSOs have already committed to, and to some extent implemented several improvements in common grid modelling that are relevant for capacity calculation. These improvements are mainly aimed at achieving a better representation of grid conditions in Southeast Europe and Ukraine. Examples

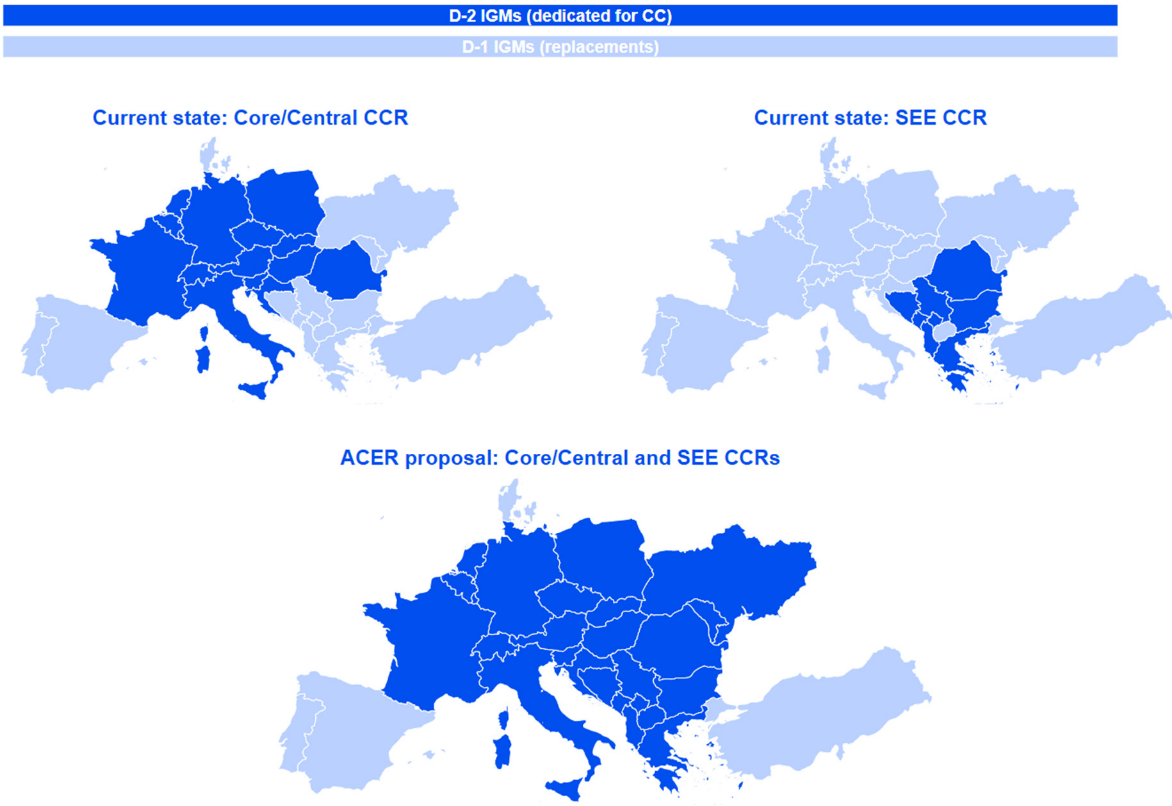
[9] This would be particularly important for cross-border lines where one TSO introduces curative remedial actions, since congestion management on such lines is a shared responsibility of both TSOs.

include the integration of two-day-ahead models from Balkan TSOs, both EU and non-EU, into the Core CGM, as well as the extension of the Net Position Forecast to include non-Core areas.

Nevertheless, further coordination between Central and Southeast Europe in grid modelling would provide a more accurate representation of system conditions for capacity calculation. This also includes the CCRs expected to become operational in the future, namely Central Europe, East-Central Europe and Eastern Europe. In light of this, ACER proposes:

1. TSOs to exchange the most representative two-day-ahead individual grid models, at least between the CCRs in Central and Southeast Europe, so that they can be taken into account in each regional CGM used for capacity calculation.
2. TSOs in Central and Southeast Europe to use the same forecast of exchanges (Net Position Forecast) for producing IGMs and creating the CGMs, through the set-up of a common forecast of exchanges that covers, at least, the bidding zones of Central and Southeast Europe.
3. Progressively moving towards a single CGM for capacity calculation, to be used for regional capacity calculation processes across at least Central and Southeast Europe, including Energy Community contracting parties.

Figure 31: Usage of individual grid models (IGM) for creating common grid model (CGM) of Continental Europe, for the day-ahead capacity calculation processes of Core and SEE



Source: ACER elaboration based on TSO information.

2.6. Improvements to the regional outage planning coordination processes

Outages of transmission assets have a significant impact on available cross-zonal capacities, and thus on cross-zonal trade and resulting price differences. During summer 2024, planned outages on cross-border lines between Austria and Hungary scheduled during several weeks of the summer period significantly reduced possibilities for trade between Central and Southeast Europe, preventing cross-border trade to further mitigate price spikes in Southeast Europe.

Considering the significant regional impact of the unavailability of transmission assets on both system operation and price formation, outage planning requires significant coordination among TSOs. Currently, the regional outage planning coordination is tasked to Regional Coordination Centres, as part of their obligations under Regulation (EU) 2019/943.

The regional coordination of outage planning takes place in two different time frames. Outage plans of relevant transmission elements created by TSOs are first coordinated on a yearly level and then reassessed on a week-ahead level on the basis of adjusted year-ahead grid models. In both cases, regional processes are based solely on a grid security criterion: RCCs will identify any operational security violation in the network that cannot be addressed with non-costly remedial actions (defined as Outage Planning Incompatibility) and propose recommendations to address it.

In the security assessment, RCCs may recommend cross-border redispatching as a solution to the identified Outage Planning Incompatibility (OPI), before proposing rescheduling or cancelling of a given outage[10]. Given that cross-border redispatching is not actually triggered until after the day-ahead market, if such a solution is accepted by TSOs and the planned outage is maintained, it will likely result in consequently lower cross-zonal capacities as the outage will be included in the grid models used later on for capacity calculation. Where the outage remains included in the grid models used for later capacity calculation, the identified security concern may ultimately be addressed through lower cross-zonal exchanges rather than through the remedial action initially identified in the regional outage planning coordination process, as the identified operational security violation will not materialise.

At present, regional outage planning coordination processes do not systematically assess the impact of planned outages on cross-zonal capacity, nor do they evaluate potential adjustments to existing outage plans in light of expected or observed market conditions. Individual TSO processes to define the initial outage plans may consider their potential impact on cross-border capacity. However, such practices remain mostly bilateral, and are not coordinated nor optimised in a consistent manner at the regional level.

In practice, regional OPC processes remain organised around the shareholder structure of individual RCCs, which may result in different approaches across RCCs, including within the same CCR[11]. This is despite the existing legal framework requiring regional coordination of outage planning to be at least at the CCR level[12]. CER also understands that, in some regional processes, year-ahead and week-ahead analyses may rely on a limited number of scenarios selected partly on the basis of operational experience, rather than on fully standardised optimisation criteria.

In addition, ACER notes that the recommendations issued by RCCs in the context of regional outage planning coordination, and the extent to which these recommendations are considered by TSOs, are not regularly published or reported in sufficient detail to NRAs and ACER. Instead, only aggregated statistics on the regional coordination processes are made available through annual ENTSO-E reporting[13], resulting in a lower level of transparency than in other regional processes, such as that of capacity calculation.

[10] Due to the significant differences between the different RCC processes, some of the considerations described above may not be applicable to all RCC processes.

[11] This is the case of the Core CCR, where two RCCs are actively performing regional outage planning coordination.

[12] The legal framework defines an outage coordination region (OCR), which is to be at least of the size of a CCR.

[13] As per Article 17 of the System Operation Guideline (SOGL).

Legal background of regional outage planning coordination in relation to maximising cross-zonal trade

The existing legal framework governing regional outage planning coordination already provides that these processes must take into account not only operational security considerations, but also their impact on cross-zonal trade. This is reflected in the following two legal provisions:

- Annex I to the Electricity Regulation, which sets out the tasks of RCCs, provides in its paragraph 10.1, that the regional outage planning coordination process must ensure operational security while minimising adverse effects on cross-zonal capacity[14];
- Article 96 of the System Operation Guideline, adopted prior to the Electricity Regulation, requires year-ahead outage coordination to minimise market impact of planned outages of relevant transmission assets, while preserving system security[15].

Accordingly, ACER has identified and put forward a number of potential improvements to existing regional outage planning coordination processes, with the intention of minimising market impact. These proposals set out a direction for strengthening the current framework, which are described in the following subsections and then summarised in Table 1. The detailed methodology and procedures should be defined by TSOs and RCCs, in cooperation with the relevant NRAs and ACER.

Assessing and optimising ex-ante outage plans according to their impact on cross-zonal capacities

As outlined above, regional outage coordination processes currently only consider an operational security criterion. Where a security violation is identified in the year-ahead or week-ahead planning process, the RCC may propose non-costly or costly remedial actions to resolve the overload, or, ultimately, recommend that the planned outage be rescheduled or cancelled. In practice, however, RCCs appear to recommend the rescheduling of outages only very rarely. Instead, identified security violations are generally addressed through remedial actions while maintaining the outage plan. Where the outage remains reflected in the common grid models used in later timeframes, this can reduce the cross-zonal capacities subsequently calculated for the day-ahead market.

As already explained, the existing legal framework requires that outage planning not only ensures operational security, but also minimises its impact on cross-border trade. Accordingly, the introduction of a secondary optimisation criterion to minimise the impact of outage plans on available cross-border capacity would provide RCCs and TSOs with valuable information on the potential market implications of planned outages, both at the year-ahead and week-ahead timeframes. Such a process would support more informed decisions on whether proposed outage plans should be adjusted in order to better preserve cross-zonal trade.

This secondary optimisation criterion is currently being developed by TSCNET. However, as currently envisaged, it would be limited to using non-costly remedial actions to reduce flow on actual cross-border lines. As a result, it is expected to have only a very limited impact on cross-zonal capacity, if at all. Alternatively, this secondary optimisation criteria could compare the impact of outage plans on cross-zonal capacities across different weeks to support recommendations on potential changes in the outage plan.

A capacity indicator of this kind could be defined for both flow-based and coordinated NTC regions, using broadly similar calculation principles. In flow-based regions, the indicator could be based on the calculation of RAM (or 'relative RAM', as described beforehand) for most relevant CNECs. In

[14] Electricity Regulation, Annex I, Article 10.1: "Each Regional coordination centre shall carry out regional outage coordination in accordance with the procedures set out in the system operation guideline adopted on the basis of Article 18(5) of Regulation (EC) No 714/2009 in order to monitor the availability status of the relevant assets and coordinate their availability plans to ensure the operational security of the transmission system, while maximising the capacity of the interconnectors and the transmission systems affecting cross-zonal flows."

[15] SOGL, Article 96.3: "3. When establishing the availability status of relevant grid elements in accordance with paragraphs 1 and 2, the TSO, DSO and CDSO shall: (a) minimize the impact on the market while preserving operational security; and (b) use as a basis the availability plans submitted and developed in accordance with Article 94."

coordinated NTC regions, a similar approach could be applied, potentially focusing on the network elements that typically constrain NTC values.

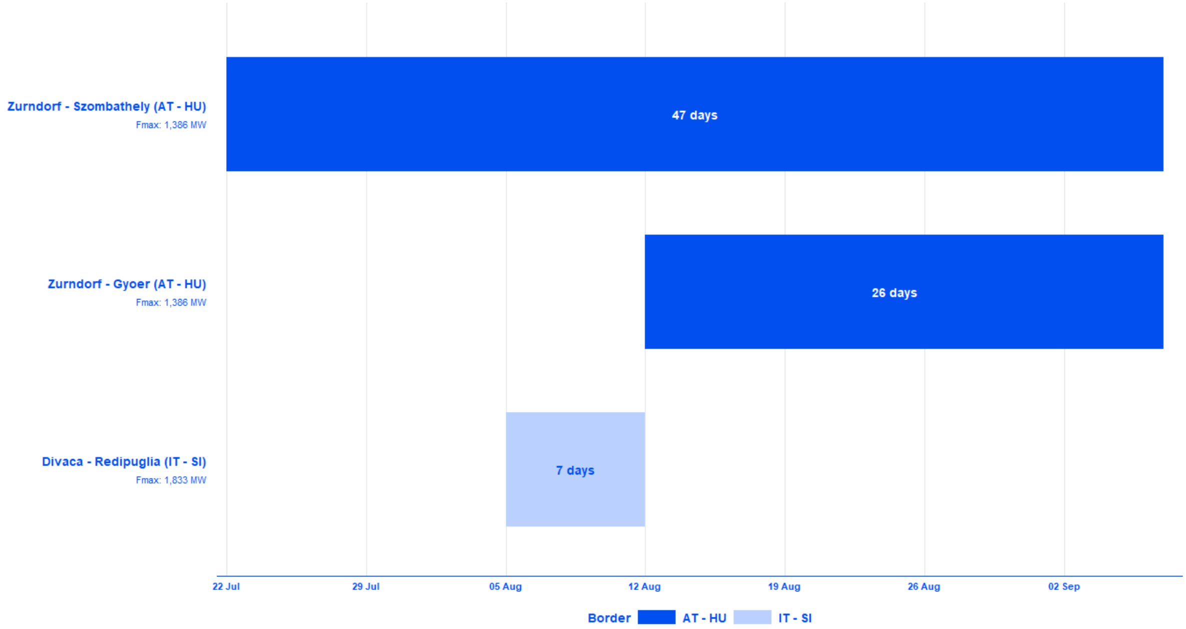
Lastly, it is important to mention that low available cross-zonal capacity does not necessarily imply significant market impact, but it remains the only relevant proxy available at the stage when outage plans are being coordinated. It could thus enable the comparison of potential variants of outage plans, with regard their effect on cross-border capacity.

Increasing the flexibility of outage planning based on observed market dynamics, wherever feasible

Secondly, and in line with the principles of maximising cross-zonal capacity and minimising market impact within outage planning, RCCs could be tasked with regularly monitoring the realised market impact of outage plans while they are being executed. Where outages are found to have a significant and persistent impact on prices and cross-border trade, RCCs could, in the week-ahead process, recommend the rescheduling or cancellation of comparable (or the same) outages planned for the subsequent weeks, where there is a reasonable expectation that similar market dynamics would continue.

The summer of 2024 provides a relevant example. During that period, outages were planned on interconnectors at the border between Austria and Hungary and remained in place for much of the summer, over several consecutive weeks, as highlighted in Figure 32. These planned outages continued long after the significant spreads on the border between Austria and Hungary had been observed. Such cases illustrate the importance of complementing ex-ante regional outage planning coordination with ongoing monitoring of realised market outcomes, so that prolonged outages with particularly severe effects on cross-zonal trade and regional price formation can be reassessed in light of actual system conditions.

Figure 32: Unavailability of cross-border lines reducing cross-border capacity in the bidding zone border between Austria and Hungary during the summer of 2024 – July to September 2024



Source: ACER elaboration based on ENTSO-E Transparency Platform.

At the same time, TSOs have repeatedly underlined that planned outages are subject to important and rigid operational constraints. For example, it may not be possible to return lines into operation at short notice, or the outage may be part of a sequence of interdependent maintenance works or network investment activities. It should therefore be recognised that any RCC recommendations to cancel or reschedule outages may be rejected by TSOs where such changes are not operationally feasible or would have a significant impact on grid development projects. Accordingly, individual TSOs could flag the details of each planned outage in advance, in particular regarding the lead time needed to bring the line back into operation, as well as the potential associated cost or impact on other processes, to feed into the RCC assessment.

To assess the severity of the market impact of outages, a set of indicators could be developed and applied consistently across regions. In flow-based regions, relevant indicators would include shadow prices on specific CNECs and observed price spreads per bidding zone borders. This can be complemented by ad hoc market simulations, using the Simulation Facility tool, where the line out of service is brought back into operation to confirm the market impact of the outage. In coordinated NTC regions on the other hand, as shadow prices on particular CNECs are not immediately available, observed price spreads would serve as the main indicator. Appropriate thresholds for identifying particularly high shadow prices and/or price spreads are to be defined in cooperation with NRAs, RCCs and TSOs.

Longer-term improvements to regional outage planning coordination

In a later stage of the improvement to the regional outage planning coordination process, RCCs could place greater emphasis on improving the underlying network modelling framework used for week-ahead analyses. This would involve the establishment of a dedicated week-ahead modelling process, including the preparation of net position forecasts, the creation of dedicated individual grid models, and their merging into a common grid model for the purposes of network analysis and capacity assessment for the following week.

In parallel, RCCs could also develop a dedicated market modelling and a forecasting framework for the week-ahead horizon, with the consideration of week-ahead transmission capacities. Such a framework would allow for a more robust forecasting for the following week and would provide a stronger basis for assessing the expected market impact of planned outages. Together, these improvements would make the week-ahead regional outage coordination process better equipped to tackle both operational security and market implications of outage planning.

Table 1: Summary of proposed improvements to existing regional OPC processes

	Outage flexibility and transparency	Ex-ante assessment on cross-zonal capacity	Adjustments based on observed market conditions
Current state	No standardised information on the possibilities to reschedule or cancel an outage	Regional analysis based only on system security.	Weekly teleconferences, focusing on security violations
		Performed on selected grid models created on the basis of year-ahead models	Identified network security issues resolved with remedial actions or, ultimately, by cancelling planned outages
Short-term	**Flagging of outage information, including its possibilities for rescheduling**	**Ex-ante optimisation of outage plans based on impact on cross-zonal capacities**	**Monitoring of realised market impact of planned outages**
			Assessment of potential market impact of planned outages for next week
	Sharing of outage plans and detected OPIs with regional NRAs		**Recommendation of rescheduling flexible outages also due to expected market stress**
Long-term	-	Dedicated week-ahead network modelling, including net position forecast	Week-ahead market modelling and forecasting framework

Considering the significant impact of outage planning on electricity price formation, particularly in Southeast Europe during the summer of 2024, ACER urges TSOs and RCCs in Central and Southeast

Europe to take the above considerations into account to strengthen the current framework for regional outage planning coordination, and to ensure that it is better aligned with existing legal provisions.

3. Activating demand response and system flexibility

As observed in Chapter 1, price formation in Southeast Europe during the summer of 2024 was strongly affected by limited system flexibility during evening peaks, when solar output declined and demand remained high. System flexibility has been traditionally provided by gas-fired and hydro power plants, capable of adjusting their output rapidly to adjust to system needs. However, demand-side response and grid-scale batteries are becoming increasingly relevant providers of this flexibility.

With increasing shares of variable renewable generation, electricity price dynamics are becoming more volatile, with wider spreads between central and evening hours of the day. This makes demand-side flexibility increasingly valuable, both for the system and for consumers. However, retail markets in Southeast Europe, with the exception of Slovenia, remain largely dominated by flat-price contracts, with limited translation of day-ahead price signals into consumer bills. This is highlighted in Figure 33.

Figure 33: Adoption of time-varying retail contracts among households across the EU and Norway – 2024 (% of total household consumers)

Source: ACER calculation based on NRA data.

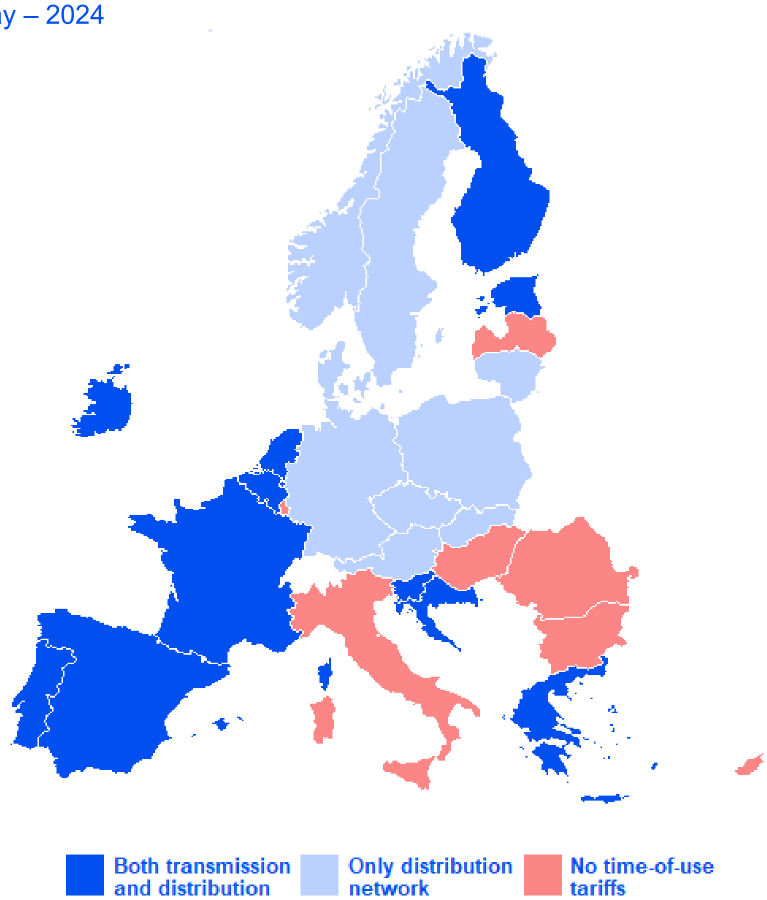
Note: For the purpose of this figure, retail contracts with any within-day time differentiation are considered.

Flat retail pricing can constitute a significant barrier to unlocking flexibility in the electricity system. In the absence of time-varying price signals, consumers are unable to benefit from lower midday prices or to reduce consumption during evening peaks, preventing system needs from translating into lower electricity bills. This is particularly relevant for consumers with greater flexibility potential, including industrial and commercial consumers and households with flexible assets such as electric vehicles, heat pumps or batteries.

Moreover, given that network costs account roughly for one third of final electricity bills, adequate price signals in the network component would also create stronger incentives for consumers to adjust their consumption patterns in response to system conditions. Alongside more dynamic retail contracts, time-of-use network tariffs can thus also play an important role in encouraging consumers to adapt their behaviour and optimise grid use. By reducing peak demand, appropriate cost signals can help avoid costly grid reinforcements and lower overall system costs for consumers.

Time-of-use signals in network tariffs are already common across much of the EU, particularly at distribution level. However, as of 2024, time-of-use network tariffs were still not in place at neither distribution nor transmission level in Bulgaria, Romania or Hungary. Figure 34 shows an overview on the status of implementation of time-of-use network tariffs, both at transmission and distribution level, in the EU and Norway.

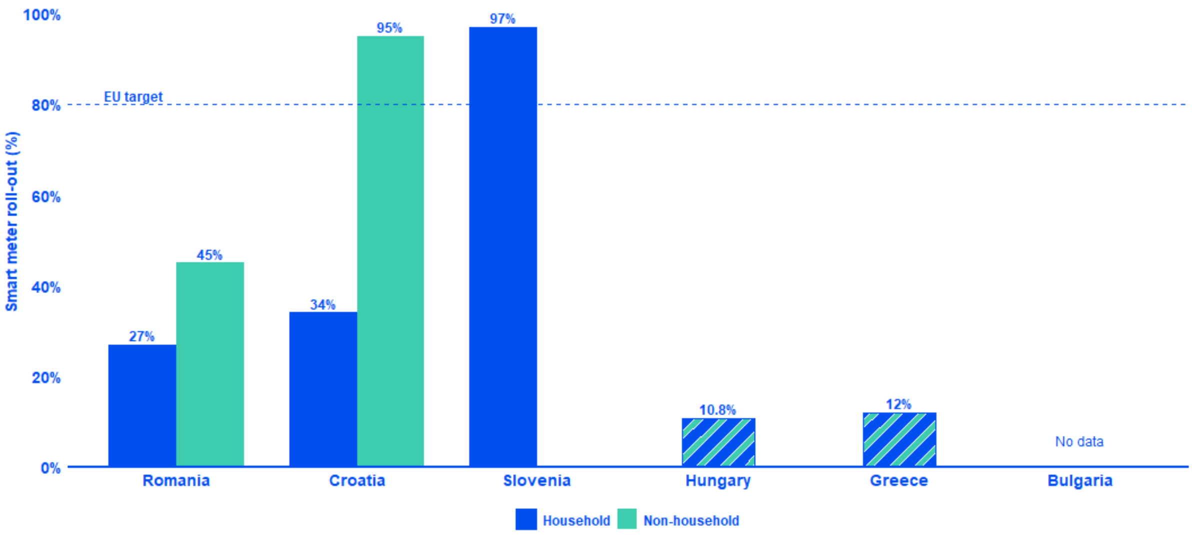
Figure 34: Uptake of time-of-use network tariffs for the transmission and distribution networks across the EU and Norway – 2024



Source: ACER calculation based on NRA data.

Smart meters are a key enabler for the uptake of time-varying retail contracts, as they provide the granular consumption data needed to support demand response. Without a widespread rollout of smart meters, the flexibility potential of consumers will remain largely untapped. Yet smart meter deployment remains uneven across the EU. In Southeast Europe in particular, rollout is still well below EU targets, materially limiting the number of consumers able to provide flexibility to the system. In Hungary and Greece, for example, only around 10% of consumers are equipped with smart meters.

Figure 35: Smart meter roll-out across Southeast Europe – 2024 (% of household and non-household consumers)



Source: ACER calculation based on NRA data.

Note: The information reported for Hungary and Greece included both household and non-household consumers. No data was available for non-household consumers in Slovenia, nor for all consumers in Bulgaria.

Moreover, in some Member States, the participation in wholesale markets and system operation services remains constrained by restrictive eligibility criteria or by legal frameworks that are incomplete or not yet fully operational. As a result, markets remain partly closed to smaller and more decentralised actors, including active customers, energy communities and aggregators.

In conclusion, the absence of time-varying retail contracts and network tariffs in some Member States in Southeast Europe limits the pass-through of wholesale price signals and network cost signals to consumers, thereby constraining their ability to provide flexibility to the market. At the same time, barriers to the non-discriminatory participation of market actors in wholesale markets and system services persist across the region[16], hindering the entry of distributed energy resources such as storage, demand response and independent aggregators.

Removing these barriers to the participation of demand and other distributed energy resources in wholesale markets and system operation services would provide much-needed system flexibility in Southeast Europe, which could in turn help mitigate high prices in evening hours. ACER's recommendations to unlock flexibility have been recently collected in the 2025 report 'Unlocking flexibility: No-regret actions to remove barriers to demand response'.

[16] Such barriers to market participation are also reported on by Energy Traders Europe in their assessment on market inefficiencies in Southeast Europe.

4. Broader improvements to market design and system planning

Lastly, this fourth section presents a set of structural improvements in market design and system planning, some of which are already under implementation, that are expected to increase the level of integration of electricity markets within Southeast Europe. Greater market integration would support more efficient price formation by increasing regional liquidity, strengthening competition, and enabling the dispatch of the most cost-effective resources available to meet demand across the region.

4.1. Increasing network interconnectivity of Southeast Europe

Beyond improving the usage of existing infrastructure, strengthening the level of interconnectivity of the Member States and regions that are currently less interconnected, such as the case of Southeast Europe, remains a key priority for improving the resilience and efficiency of the European electricity system.

Increasing the level of interconnectivity primarily requires the development of additional network infrastructure, both cross-border and internal, based on an effective assessment of the actual cross-border needs and on an efficient planning of infrastructure projects. Moreover, it calls for faster and more streamlined permitting procedures, as well as adequate mechanisms for sharing the costs of network infrastructure in accordance to the location of the benefits reaped by it.

The issues outlined above are, to some extent, already being addressed through several legislative processes at EU level. In December 2025, the European Commission presented the European Grids Package, which includes a proposal to revise the TEN-E Regulation, as well as a proposal to accelerate permit-granting procedures through amendments to the Renewable Energy Directive, the Electricity Market Design framework, and the Gas Directive.

The proposals put forward by the Commission as part of the Grids Package aim to strengthen coordination in network planning at EU level, in order to better identify cross-border infrastructure needs and plan infrastructure projects accordingly. This includes introducing more effective cost-sharing mechanisms. While the final text is still being agreed on by policymakers, including on the basis of amendments proposed by ACER and NRAs, the package is intended to address some of the observed shortcomings in the existing network development framework. Within this broader package, the Energy Highways initiative explicitly includes Southeast Europe as one of the regions in need for greater interconnectivity.

Moreover, in the current network development processes, congestion patterns that have already materialised may not be sufficiently taken into account when defining infrastructure projects and their priority, often leading to mismatches between existing needs and the timelines of projects aimed to address them.

As a complement to the above-mentioned infrastructure development initiatives, ACER also sees the need to accelerate, wherever possible, those projects aimed at addressing congestion patterns already observed today. This would imply adjusting infrastructure development plans to reflect persistent or emerging congestion in the system. This approach is also reflected in Regulation (EU) 2018/1999 on the Governance of the Energy Union, which identifies wholesale electricity price differentials between bidding zones as one of the indicators for assessing the urgency of action to increase interconnectivity.

A more dynamic and congestion-driven approach to network planning, where feasible, would help ensure that investments are directed to the areas where they can deliver the greatest benefit in terms of market integration, RES integration and security of supply. As an example, should price spreads between Southeast Europe and the rest of the EU remain persistently high over a significant period of time, it would potentially be advisable to prioritise network investments that would increase cross-zonal capacity towards this region.

4.2. Improving the design of electricity bidding zones in the EU

Well-designed bidding zones should reflect structural patterns of network congestion so that price signals accurately represent the underlying physical constraints of the system. When bidding zone configurations are appropriately aligned with structural congestion, they support more efficient price formation and improve the allocation of generation and demand across the network. In turn, this facilitates cross-zonal trade while also ensuring operational security, as a better alignment between market outcomes and network reality can reduce the volume of unscheduled loop flows affecting neighbouring zones.

Congestion within a bidding zone can be alleviated through several complementary measures. First, internal grid investments, whether AC or HVDC, can strengthen the transmission network and make a bidding zone more electrically compact. By reducing internal bottlenecks, such investments improve the ability of the zone to accommodate internal exchanges without creating adverse cross-border effects, thereby mitigating the negative impact of loop flows on neighbouring systems.

Second, the deployment of flexible network assets can support a more efficient management of congestion. Technologies capable of controlling power flows, such as phase-shifting transformers, synchronous series static compensators (or SSSCs), and HVDC links, provide TSOs with greater controllability and can help direct electricity along more efficient paths. This increases the operational flexibility of the network and can reduce the need for more costly and less efficient remedial actions, such as redispatching.

Lastly, where structural congestion cannot be adequately and promptly addressed through internal grid reinforcement or operational measures alone, bidding zone reconfiguration may be appropriate. In this context, the recommendations stemming from ENTSO-E's 2025 bidding zone review provide an important basis for assessing whether the existing bidding zone configuration remains efficient. In some cases, reconfiguring bidding zones may offer a more durable and less costly solution to persistent structural congestion, while improving the overall efficiency of market outcomes. In this regard, a recent study published by the European Commission's Joint Research Centre (JRC) estimated that a more granular delineation of electricity bidding zones in the EU could generate significant cost-savings for the internal electricity market.

Ensuring that existing bidding zones minimise negative externalities on neighbouring systems, mainly in the form of loop flows, would support higher cross-zonal capacities across all market timeframes. This, in turn, would enhance the ability of the internal electricity market to prioritise exchanges towards regions facing higher import needs, as was the case in Southeast Europe during the summer of 2024.

4.3. Expanding market coupling and flow-based approach in Southeast and Eastern Europe

The aim of market coupling is to create a single pan-European electricity market. To this end, the Single Day-Ahead Coupling (SDAC) and the Single Intraday Coupling (SIDC) allocate scarce cross-border transmission capacity in the most efficient manner by coupling wholesale electricity markets from different regions through a common algorithm. This algorithm simultaneously considers cross-border transmission constraints and matches supply and demand across bidding zones, thereby maximising overall social welfare.

An integrated electricity market improves the efficiency of cross-border trading in several ways. It promotes competition by enabling market participants to compete across a wider geographical area, increasing market liquidity and allowing for generation resources across Europe to be used more efficiently. As a result, electricity can flow to where it is most valued, reducing the overall cost of meeting demand.

By contrast, on borders that are not part of market coupling, cross-zonal capacity is typically allocated explicitly, meaning that capacity and energy are traded as separate products. Under this approach, market participants must anticipate the efficient trading direction and acquire transmission capacity before the day-ahead energy market takes place. This creates additional complexity and may lead to less efficient outcomes, particularly where market participants are unable to accurately predict price differentials and network conditions.

Expanding market coupling to Energy Community bidding zones

As introduced in Chapter 1, price formation in Southeast Europe is influenced by electricity exchanges between EU and Energy Community bidding zones, for which capacity is allocated explicitly. Extending the EU internal electricity market to these bidding zones would improve the allocation of cross-zonal capacity in the region by enabling the implicit allocation of transmission capacity together with electricity trading.

Deeper market integration in Southeast Europe would strengthen competition across the region and support a more efficient price formation process. It would reduce the risks associated with limited liquidity and market concentration in smaller bidding zones, where insufficient competition can amplify price volatility and lead to less efficient outcomes. By broadening the geographic scope of competition, market coupling would help align prices more closely with underlying supply and demand conditions.

In situations of system stress, market coupling would also help ensure that available transmission capacity is directed to where it creates the greatest value. This would support the affected bidding zones, improve the overall efficiency of cross-border exchanges, and contribute to a more coordinated regional response to tight system conditions.

However, it is important to underline that a prerequisite for the integration of Energy Community bidding zones into the EU's internal electricity market is the full transposition of the EU energy acquis by the Energy Community contracting parties.

Introducing flow-based capacity calculation and allocation to Southeast and Eastern Europe

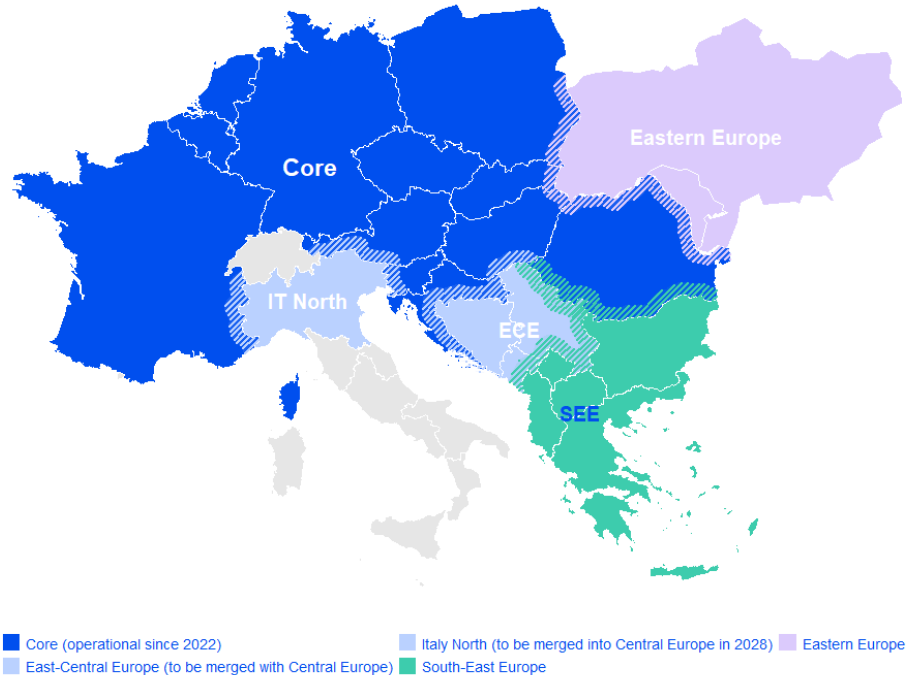
Flow-based market coupling allocates scarce transmission capacity across the region by considering the constraints on each critical network element and assigning capacity to the combination of trades that delivers the highest overall welfare. Unlike an NTC-based approach, it is not limited by an ex-ante bilateral split of transmission capacity across individual bidding zone borders. This allows the allocation process to better reflect the physical reality of a highly interconnected electricity system and to make more efficient use of available network capacity.

Experience in the Core and Nordic CCRs shows that flow-based market coupling can deliver tangible benefits, particularly in highly meshed systems. It can increase trading opportunities, thereby supporting greater price convergence and helping to dampen extreme price spreads and peak prices, especially in periods of system scarcity. It also increases transparency by providing clearer information on which network elements are constraining cross-zonal trade. The merger of the Core and Italy North CCRs into the Central Europe CCR, with the application of a flow-based approach, is also expected to have positive effect on available capacities and regional operational security coordination.

Once NTC-based market coupling has been implemented across the newly defined CCRs in Southeast Europe, namely East-Central Europe, South-East Europe, Eastern Europe and Italy-Montenegro, the NTC-based approach to capacity calculation and allocation should gradually be replaced by the progressive introduction of flow-based market coupling, including through a gradual accession to the Central Europe CCR.

Such a transition would further deepen the integration of electricity markets in Southeast Europe, where the electricity network is highly meshed and bidding zone borders are strongly interdependent. Under these conditions, a flow-based approach is expected to deliver significant added value compared with the NTC-based alternative, as it is better suited to managing the network effects and trade-offs that arise in such systems.

Figure 36: Newly defined capacity calculation regions in Central and Southeast Europe to progressively introduce flow-based market coupling



Source: ACER elaboration.

Note: The details of the newly defined capacity calculation region are outlined in ACER Decision 10/2025 on the amendment to the determination of capacity calculation regions.

Expanding flow-based capacity calculation and allocation to later market timeframes, where already implemented in day-ahead

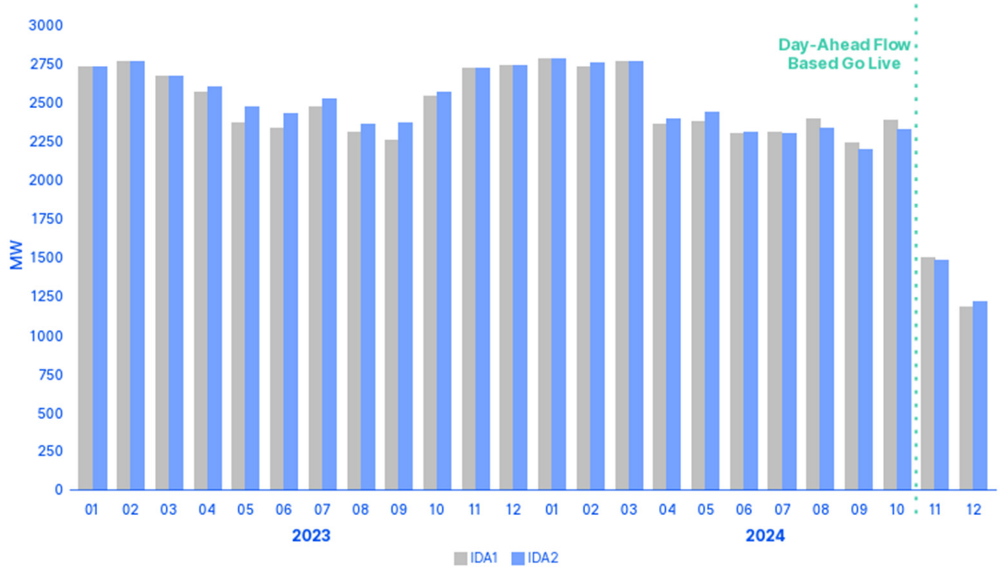
The inefficiencies associated with NTC-based allocation in the day-ahead market, in areas with strongly interdependent bidding zone borders, are also relevant in later market timeframes. At present, all intraday and balancing trading across the EU continues to rely on ATC-based allocation, mostly using the leftovers from previous market timeframes, while flow-based market coupling has so far been implemented in the day-ahead market in the Core and Nordic regions.

As noted above, flow-based market coupling captures the interdependencies between exchanges across different bidding zone borders, whereas ATC-based approaches treat each bilateral exchange in isolation. This distinction becomes even more important in intraday and balancing timeframes, where market conditions are more dynamic and transmission constraints are more strongly affected by the outcome of earlier market clearings.

In intraday and balancing markets, ATC allocation may be even less efficient than in the day-ahead timeframe, because market clearing no longer starts from a zero-exchange position, but rather from the outcome of the day-ahead market and previous intraday allocations. From this non-zero starting point, the extraction of ATCs from flow-based domains can lead to highly constraining outcomes, including bidding zone borders with no remaining capacity in either direction and, in some cases, effectively isolated bidding zones.

As an example, Figure 37 shows the drop in intraday ATCs observed in the Nordic CCR after the implementation of flow-based market coupling in the day-ahead market, back in October of 2024. This drop is precisely caused by the need to extract ATC values from flow-based domains, starting from the day-ahead market clearing point, due to intraday auctions not allowing for flow-based allocation. Such a drop highlights the inherent inefficiency of an ATC-based intraday market that follows a day-ahead market using flow-based capacity allocation.

Figure 37: Impact of ATC extraction from flow-based domains in the Nordic CCR, compared to ATC leftovers prior to the implementation of flow-based market coupling in day-ahead – 2023 to 2024 (MW)



Source: ACER 2025 Monitoring Report on cross-zonal capacities and congestion management

Note: The metric shows the sum of capacity released in both directions of a given bidding zone border, averaged for the whole region. The capacity levels displayed for the period before the implementation of pan-European intraday auctions correspond to the cross-zonal capacity released for continuous trading at 15:00 and 22:00.

ACER considers that significant benefits could be achieved by introducing flow-based allocation in market timeframes after day-ahead. This is to be implemented as soon as possible in all pan-European intraday auctions, and at a later stage in continuous intraday trading and balancing markets. Currently, the introduction of flow-based is only legally mandated in the intraday timeframe, wherever it has been implemented in the day-ahead market, while its extension to balancing markets is still being discussed.

A more efficient allocation of cross-zonal capacities, and consequently improved price signals in intraday and balancing timeframes, would also have positive knock-on effects in the day-ahead market, as market participants will typically reflect the opportunity costs of later timeframes in their day-ahead bidding behaviour.

Conclusions

Price spikes in Southeast Europe in 2024 were largely driven by a combination of tight supply-demand conditions in the region, and limited opportunities to import more electricity from the rest of the EU. Periods of high demand, often associated with extreme weather conditions, were matched by limited flexible supply resources capable of responding rapidly to changing system needs. As a result, the system relied at times on a relatively small number of flexible generation assets to meet the evening demand peaks, putting strong upward pressure on prices.

At the same time, limited cross-border transmission capacity constrained the region's ability to import lower-priced electricity from neighbouring markets, thereby reducing the extent to which market integration could mitigate higher prices in the region. This was exacerbated during the summer of 2024, when planned outages on the border between Austria and Hungary further reduced the available capacity towards Southeast Europe from the rest of the EU. Together, these factors significantly amplified short-term price volatility and contributed to pronounced price spikes across the region.

While fundamental market conditions in 2025 did not result in electricity prices as high as they did during Summer 2024, price spreads between Southeast and Central Europe remained significant during the entire year of 2025, as well as during the first months of 2026. This indicates that the price spikes of 2024 were not merely an isolated event caused by exceptional weather conditions or specific outages but rather revealed deeper structural challenges in the region. Addressing these challenges requires both immediate and long-term action.

Accelerate deployment of lower-cost and faster network upgrades

In the near term, priority should be given to lower-cost and faster-to-deploy network measures that can unlock additional transmission capacity. Grid enhancing technologies, such as dynamic line rating and the replacement of standard conductors with high-temperature low-sag alternatives, can increase the usable capacity of existing infrastructure more rapidly than conventional grid expansion projects, and at a lower cost. With due consideration to investment costs and system security, these measures should be assessed by all TSOs and NRAs in Central and Southeast Europe and, where deemed appropriate, accelerated in order to deliver timely benefits to the region, particularly ahead of future periods of seasonal system stress.

Continue strengthening regional coordination in system operation

At the same time, stronger regional operational coordination remains essential. Continued improvements in TSO coordination, including via a more relevant role of RCCs in outage planning, and the wider use of curative remedial actions, can help maximise the capacity made available to the market while preserving operational security. In this report, ACER has identified significant shortcomings in existing regional outage planning coordination processes, particularly in their ability to minimise the impact of outages on cross-zonal trade, as well as in the optimisation of curative remedial actions in capacity calculation in the Core region.

Implement EU legal requirements that aim at further integrating markets

More broadly, Southeast Europe would benefit from a stronger implementation of existing EU legal and regulatory requirements aimed at enhancing market integration in the EU. These include finalising the implementation of the minimum 70% requirement across Central and Southeast Europe, including on bidding zone borders with Energy Community countries, the extension of market coupling to non-EU neighbours in Southeast Europe, and the progressive expansion of flow-based capacity calculation and allocation in Southeast Europe, both geographically and to closer-to-real-time market timeframes.

Increase the interconnectivity of Southeast Europe by accelerating network investments

Beyond operational improvements and upgrades to the existing network, the observed price dynamics in Southeast Europe over recent years also point to the need to accelerate investment projects with a high impact on regional market integration and security of supply in the region. It is important to note that increasing cross-zonal capacity at strategic locations in the network can result in significant benefits for the whole region. Mechanisms for sharing the costs between the Member States where the grid is reinforced and the Member States which benefit from it are therefore essential for a fair distribution of costs and benefits.

Unlock system flexibility in Southeast Europe, by removing market barriers and mobilising investments in flexible assets

Finally, reducing the frequency and severity of future price spikes in Southeast Europe will also require local actions, such as removing market barriers to unlock greater system flexibility and increasing market competition. Storage, demand response, and flexible generation capacity can all play an important role in allowing the system to rapidly respond to sharp changes in demand and supply, particularly during evening peaks and other stress situations. Strengthening the participation of demand in wholesale markets, and the further deployment of short-term flexibility assets, would greatly improve the resilience and degree of competition of electricity markets in Southeast Europe, and support a more stable and efficient price formation process.