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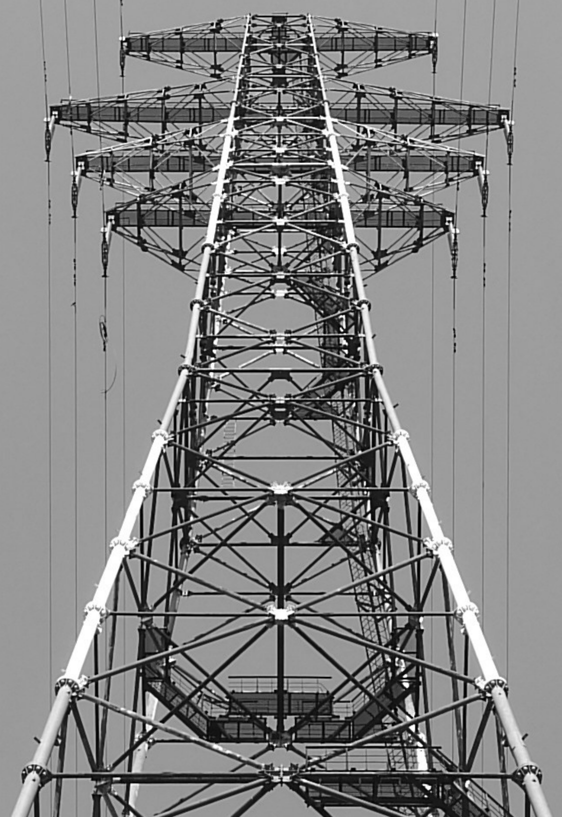
Plug, baby, plug: Unlocking Europe's electricity market

11 March 2025



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Executive Summary

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- **Europe's electricity infrastructure and market design disparities have become major obstacles to the green transition.** Delays in grid development have created a backlog of over 800 GW of wind and solar capacity awaiting connection, nearly double the current supply. Meanwhile, persistently high electricity prices are undermining industrial competitiveness and burdening consumers. Without urgent grid investments and modernization, Europe risks falling short of its 2050 net-zero target, which requires intermittent renewables to supply 82% of the continent's electricity.

- **The lack of grid flexibility exacerbates intraday price volatility, with high electricity prices during peak demand and negative prices during off-peak hours.** In Germany alone, compensation for renewables reached EUR20.9bn in 2024. Grid congestion costs are still lower (EUR2.5bn in 2019) but are projected to surge to EUR12.3bn by 2030 and EUR56.7bn by 2040 without upgrades. These costs ultimately impact electricity prices, with potential increases of +22% by 2030 and up to +103% by 2040 under a business-as-usual (BAU) scenario. However, the economic fallout extends beyond electricity prices, threatening GDP growth and sectoral competitiveness. Germany could face EUR1.6trn in GDP losses by 2050, with public services (EUR585bn in losses), finance (EUR495bn) and retail and wholesale trade (EUR266bn) being most affected.

- **Transitioning the EU's electricity sector could lower final prices by -11% as soon as 2035 and by -30% in 2040.** But this will require EUR2.3trn in grid infrastructure investments by 2050, with annual funding averaging EUR90.8bn. To meet the EU's 90% emissions reduction target by 2040, front-loaded investments could push annual investment needs beyond EUR100bn. The distribution network will absorb 56% of total investments, requiring EUR220bn by 2030, with Germany, France, and Italy accounting for 50% of the spending. Meanwhile, transmission infrastructure, set to expand by +28% by 2030, will require EUR694bn by 2050. Beyond domestic grids, interconnector and storage capacity must double by 2030, adding EUR10bn annually but delivering EUR23bn in long-term savings by 2050.

- **To reduce grid investment costs and enhance efficiency, Europe must make demand more flexible, leverage sector coupling and electric vehicle (EV) integration and improve its market design.** Expanding smart meter use can reduce peak loads and storage needs while lowering household energy consumption by 2-10%. Power-to-X technologies can utilize surplus renewable electricity to power downstream industries. In Germany alone, the 10 TWh of curtailed renewables in 2023 could have been used to produce green hydrogen, covering 12% of national demand without additional generation. EVs equipped with bi-directional charging can further enhance grid stability, reduce congestion and cut EU emissions by -7%. Finally, aligning electricity pricing zones with grid conditions would lower congestion costs and improve renewable integration, ensuring a more flexible and cost-efficient energy transition.

- **While greater integration of European electricity markets through expanded interconnector capacity can enhance system resilience and lower costs, it also raises challenges related to energy autonomy, market competition and regional price disparities.** Countries with lower electricity prices may see costs rise, creating political tensions, as seen in Sweden's cancellation of the Hansa Power Bridge over local price concerns. A surcharge-and-subsidy mechanism on electricity exports could help ensure a fair distribution of benefits, mitigating price disparities while supporting investment in interconnectors. Our analysis of the Sweden-Germany interconnection shows that implementing the 0.7 GW Hansa Power Bridge interconnector could generate EUR30bn in annual savings, vastly outweighing the EUR0.6bn investment cost. Implementing tailored pricing mechanisms and better market coordination will be key to maximizing the benefits of deeper integration while addressing distributional concerns.

- **With Europe facing fiscal constraints and rising military spending, relying solely on public financing to meet grid investment needs is not feasible.** To bridge the EUR30-50bn annual funding gap, regulatory harmonization, private sector mobilization and new financing instruments will be essential. Structural reforms, such as advancing the Capital Markets Union (CMU) and establishing an Independent System Operator (ISO) would further improve capital flows, optimize grid planning and enhance cross-border electricity trade. Strengthening the Connecting Europe Facility (CEF) and other EU-level funding mechanisms will also be crucial to ensuring efficient deployment of capital. Expanding green bonds, transition funds and adjusting capital requirements can help attract institutional investors while targeted fiscal incentives, such as amortization accounts and tax credits, can ease financial pressures. By diversifying funding sources and streamlining infrastructure approvals, Europe can accelerate its grid expansion while maintaining economic sustainability.

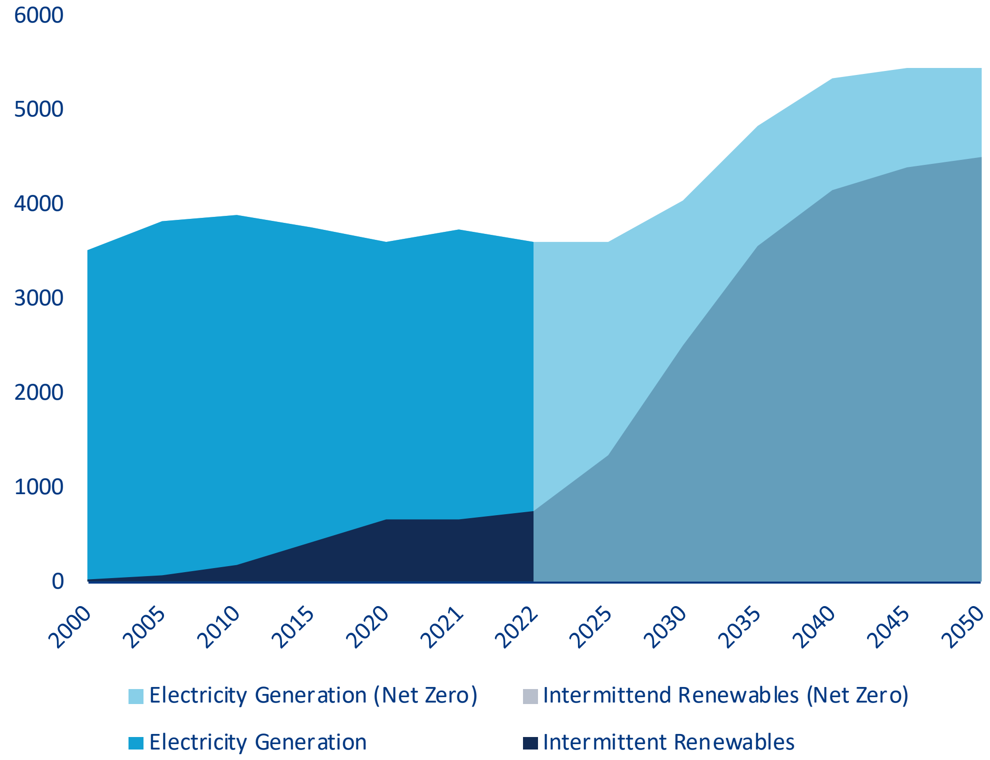
Europe's electricity market: a bottleneck for transition and competitiveness?

Just 10 years after the Paris Agreement and five years before the Fit for 55 deadline, Europe stands at a critical juncture in its decarbonization efforts. Reaching decarbonization targets while lowering the continent's energy costs critically depends on the rapid build-up of renewable capacities and an efficient integration into the region's power system. Under Europe's updated Renewable Energy Directive (RED), this would require final energy consumption from renewables to increase from 24.5% in 2023 to 42.5% by 2030. The primary drivers of this development are the expansion of wind and solar capacities. Wind power must increase by +52.9% until 2030, reaching 425 GW, while solar would need to see an even steeper increase of around 262 GW in five years, increasing the existent supply by more than 75%. Financing this expansion of renewables will be challenging, with annual investment costs for wind and solar estimated at around EUR101bn through 2030.[1] However, Europe's biggest obstacle may not be funding but rather the lack of supporting infrastructure.

In recent years, Europe's electricity infrastructure and market design disparities have increasingly become a roadblock for the green transition and competitiveness. Delays in grid development have led to a massive backlog, preventing new renewable capacity from coming online. As a result, over 800 GW of wind and solar capacity – nearly double the current supply – is awaiting grid connection at a time when the continent is struggling with persistently high electricity prices.[2] These setbacks threaten Europe's 2050 net-zero ambitions, which require intermittent renewables to generate 82% of the continent's electricity by mid-century (Figure 1). The transition away from fossil fuels via increased electrification, combined with rising electricity demand from data centers, will also necessitate an even greater expansion of grid infrastructure to keep pace with growing power needs. In a net-zero consistent scenario, electricity production would need to grow by approximately +50% by 2050. However, without adequate grid infrastructure to support this increase in demand and the expansion of renewable energy sources, the EU will struggle to meet its climate targets. This shortfall would impact not only the energy sector but also downstream industries that rely on the decarbonization of electricity to achieve their own net-zero goals.

[1] NGFS V5 Net Zero Scenario REMIND Model
[2] Aurora Energy Research

Figure 1: Electricity generation and intermittent renewable share for Europe in net-zero scenario (in GWh/year)



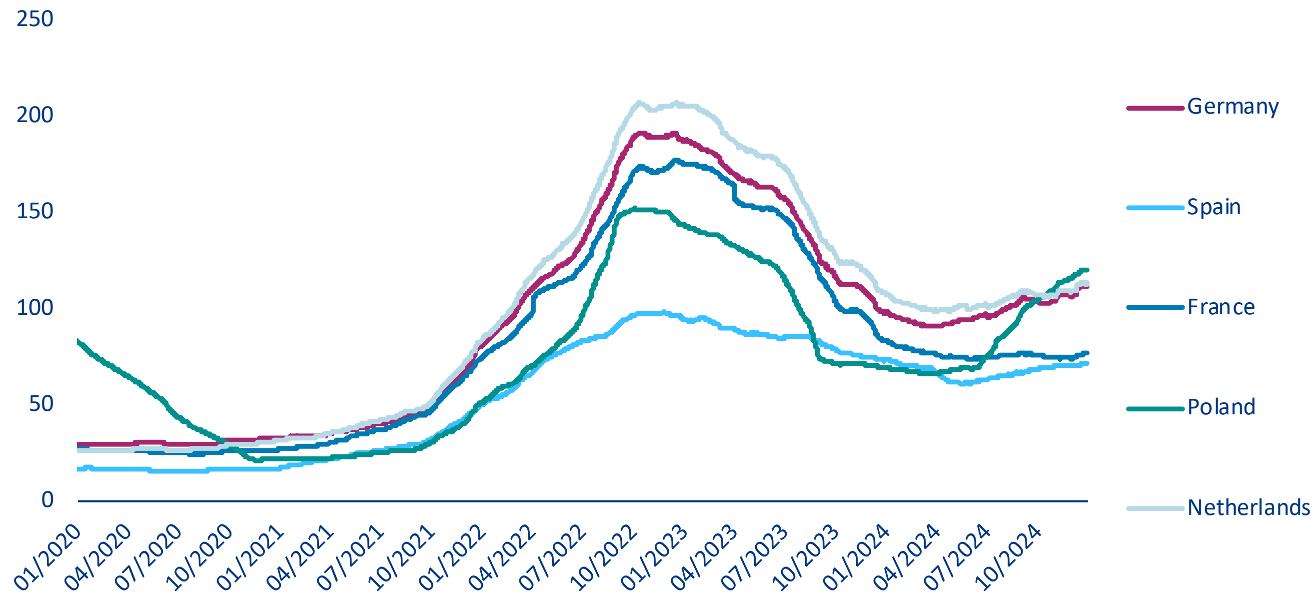
Sources: IRENA, NGFS (REMIND Model), Allianz Research

Meanwhile, the lack of grid flexibility – both in renewable electricity supply and consumer demand – exacerbates intraday price volatility. As a result, during periods of peak demand – typically in the evening – consumers face high electricity prices, while daytime prices increasingly drop into negative territory. In 2024, EU electricity prices were negative for an average of 308 hours across countries, reflecting the ongoing challenges of balancing supply and demand. This mismatch hurts both producers and consumers, and needs to be financed by already strained government budgets. In Germany alone, the compensation to renewable electricity production (§19 EEG) – which reimburses producers when market prices fall below a guaranteed rate – cost the government around EUR20.9bn in 2024. Without the expansion of grid infrastructure and an improvement of demand-side flexibility, there is also the risk of further delays in the transition. As companies observe more volatile prices, they experience higher uncertainty, which in turn discourages long-term investments in renewable energy. This was highlighted in recent months with several wind turbine tenders not receiving any bidders.[3]

Integrating more grid storage could improve power system flexibility, but it comes with its own challenges. With lithium-ion battery prices declining more than 85% over the last 10 years, reaching EUR110/kWh in 2024, investments into grid storage have become substantially cheaper. Simultaneously, the rapid expansion of intermittent renewables, coupled with Europe's pivot away from Russian gas, has widened intraday electricity price spreads (Figure 2). This growing market volatility has strengthened the business case for energy storage, allowing investors to capitalize on greater price differentials, improving the overall return on investment. The consequence of this development is a substantial increase in the development of battery storage projects. In Germany alone, project developers have requested to add a staggering 226 GW of large-scale energy storage to the power grid. However, the expected system needs for storage in the country are estimated at just 56GW by 2045. Given the significant oversupply, grid operators must evaluate which projects can be effectively integrated into the system in a manner that ensures stability and efficiency. While an insufficient storage capacity has led to higher price volatility and rising system costs, an oversupply and misallocation of storage could put a strain on the network infrastructure, potentially leading to costly congestion.

[3] Wind Europe

Figure 2: Intraday wholesale power spreads: 12-month rolling average (in EUR/MWh)



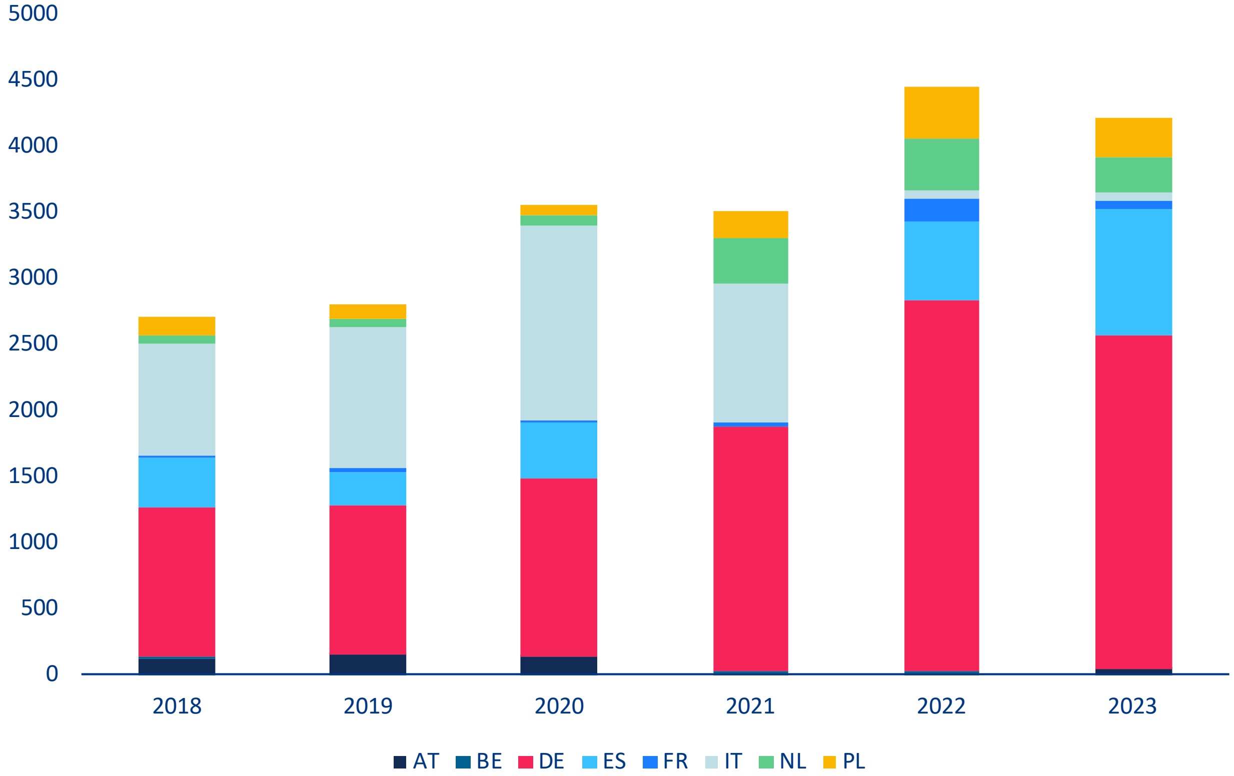
Sources: Allianz Research, ENTSO-E Transparency Platform

More volatile electricity generation from intermittent renewables and lacking network infrastructure increase the risk of grid congestion. When regional energy production is high, transmission constraints may prevent electricity from reaching demand centers without overloading the grid. To manage this, grid operators either reduce overall generation (curtailment) or adjust production by lowering output in congested areas while increasing it in high-demand regions (redispatch). While part of the standard network management toolkit, the need for conducting these grid interventions has increased considerably in Europe, with management costs rising by +55% between 2018 and 2023 to EUR4.2bn (Figure 3). These costs stem from compensation payments to power producers for redispatch adjustments and curtailed electricity, higher operational expenses for grid balancing and investments in short-term flexibility measures. This trend is largely driven by the rapid expansion of intermittent renewable energy, which has more than doubled in Europe's largest economies over the past decade.

Countries with high shares of wind and solar power – such as Germany, Spain and the Netherlands, where renewables exceed 30% of the energy mix – also face the highest congestion costs (Figure 4). Germany in particular bears the brunt, spending over EUR2.5bn per year, or nearly 60% of the EU's total congestion management costs. Beyond renewable capacity growth, the country's soaring network costs stem from multiple structural issues. Grid expansion is severely delayed – currently seven years behind schedule –limiting the ability to transmit electricity efficiently. Additionally, the lack of demand-side flexibility and storage infrastructure further strains the system. A major challenge is also the geographical mismatch between energy generation hubs, located primarily in the north, and the main demand centers in the south. Even though the costs of curtailment and redispatch are already significant today, failing to address congestion issues while continuing to expand renewable capacity could drive EU-wide power costs up more than 20-fold by 2040, placing a strain on consumers.[4]

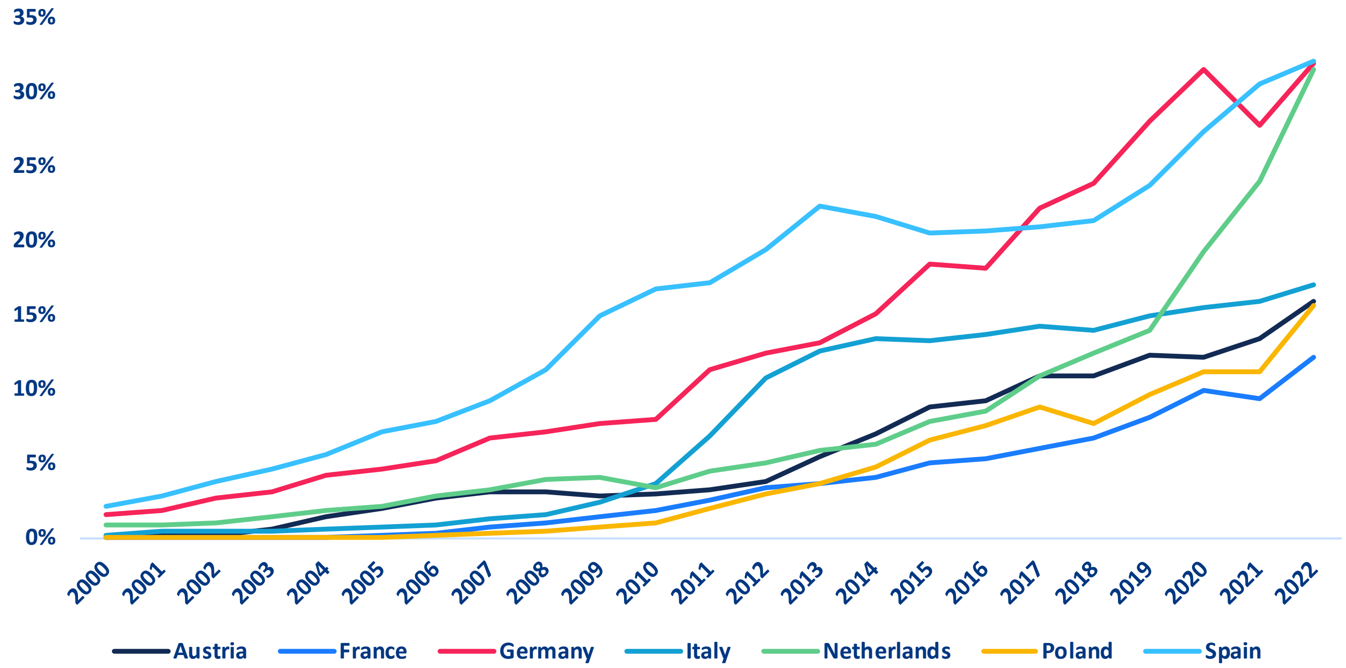
[4] Redispatch and Congestion Management (JRC)

Figure 3: Congestion management cost in Europe (in EUR mn)

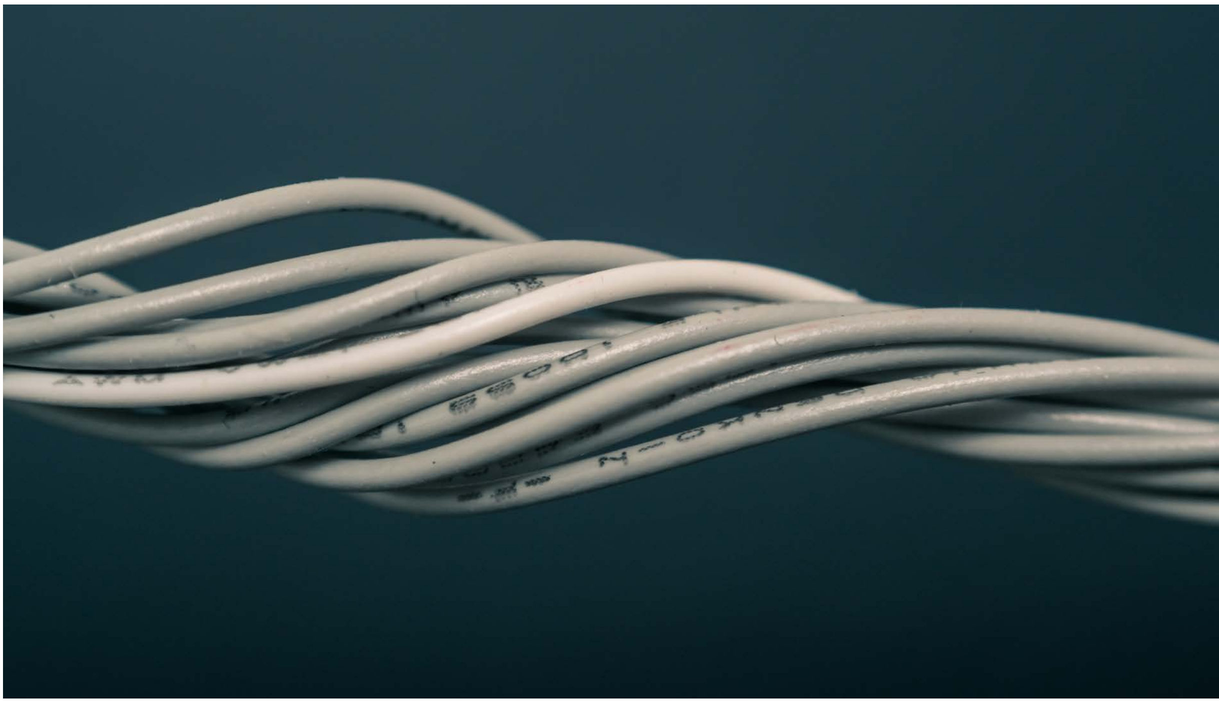


Sources: ACER monitoring reports, Allianz Research

Figure 4: Share of intermittent renewables in the electricity mix of selected European countries



Sources: IRENA, Allianz Research



Powering progress: The investment imperative for a resilient grid

Transitioning the EU's electricity market will require an average annual investment of EUR90.8bn and a total of around EUR2.3trn by 2050 (Table 1). Compared to the current annual investment of approximately EUR60bn, funding needs until 2030 must increase by at least +30% (EUR18bn per year). Post-2030, assuming a linear investment trend, annual investments would average EUR94bn between 2030 and 2050. However, to meet the EU's 90% emissions reduction target by 2040, a faster expansion of renewables is essential at the beginning of the next decade. That means grid investments will need to be front-loaded. As a result, total grid investment needs could exceed EUR100bn per year until 2040. The distribution network will require the largest share of this investment, demanding at least 56% of total funding – an estimated EUR220bn by 2030. The highest investment needs are concentrated in Germany, France and Italy, which together account for roughly 50% of total distribution network investments.[5] Meanwhile, the transmission network, expected to expand by +28% by 2030, will also require substantial funding, estimated between EUR476bn and EUR911bn by 2050.

[5] Grids for speed (Eurelectric)

Table 1: Investment needs in Europe's power system (in EUR bn)

Grid Component	2025-2030		2030-2050		Total until 2050
	annual	total	annual	total	
Transmission network	26	130 (91-166)	30	600 (385-755)	**730**
Distribution network	44	220 (175-252)	53	1060 (924-1300)	**1280**
Interconnectors & Storage	8	40 (25-58)	11	220 (190-231)	**260**

Sources: Allianz Research based on ENTSO-E, EMBER, ACER, Eurelectric, European Commission, ERT and Goldman Sachs

An efficient transition of Europe's power system will require not only network investments but also a significant expansion of interconnector capacity and battery storage. According to the European Network of Transmission System Operators for Electricity (ENTSO-E), Europe currently has 126 GW of interconnection capacity and 24 GW of storage. By 2030, both cross-border transmission infrastructure and energy storage capacity will need to double, with further increases to 385 GW of interconnector capacity and 540 GW of storage by 2050. This expansion is expected to add around EUR10bn annually to grid investment costs. However, these investments would also enhance system flexibility, reducing the need for costly congestion-management interventions. ENTSO-E estimates that increased interconnection and storage could generate EUR23bn in annual benefits by 2050, resulting in a net system cost reduction of approximately EUR10bn per year. Beyond cost savings, interconnection and storage improvements would also help stabilize electricity prices. Greater grid storage would allow for better supply distribution throughout the day, mitigating price spikes during peak demand periods. At the same time, enhanced interconnectivity would facilitate a more efficient distribution of electricity across Europe, leading to lower average costs for both industries and consumers.

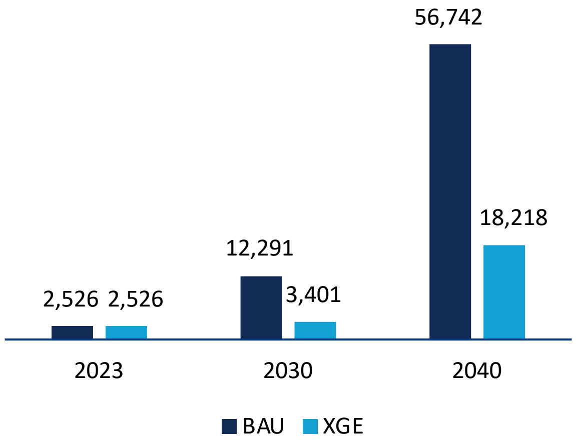
Advancing the integration of European energy markets is crucial for a more resilient and efficient power system, especially as the transition to renewables increases supply volatility. Expanding interconnections and storage capacity will not only enhance system flexibility but also reduce reliance on national backup capacity by 15-19%, lowering both costs and CO2 emissions.[6] Cross-border trade has already proven its value in crises, such as the European energy crisis and France's nuclear outages in 2022, by balancing supply shortages and stabilizing electricity prices. Looking ahead, a "Managed Transition Scenario", where interconnections are expanded and renewables are deployed in optimal locations, could reduce wholesale electricity prices by -40% in the long run.[7] In contrast, a "Frustrated Transition Scenario", where national governments prioritize domestic energy policies over European cooperation, would lead to higher costs, inefficiencies and increased volatility. The European Commission estimates that deeper integration could generate EUR16-43bn in annual welfare gains, reinforcing the economic case for a more interconnected market. However, unlocking these benefits requires overcoming key challenges. Maintaining some level of energy autonomy, ensuring fair cost distribution and supporting producers facing increased competition will be crucial. Price disparities between regions could also lead to policy tensions, as seen in Sweden's cancellation of the Hansa Power Bridge over concerns about rising local electricity prices. To fully realize the advantages of integration, expanding interconnectors, modernizing grid infrastructure and implementing EU-wide funding mechanisms will be essential. Additionally, cross-continental projects like Xlinks, which aims to connect Europe with Morocco's renewable energy resources, could further strengthen energy security and affordability in the long term.

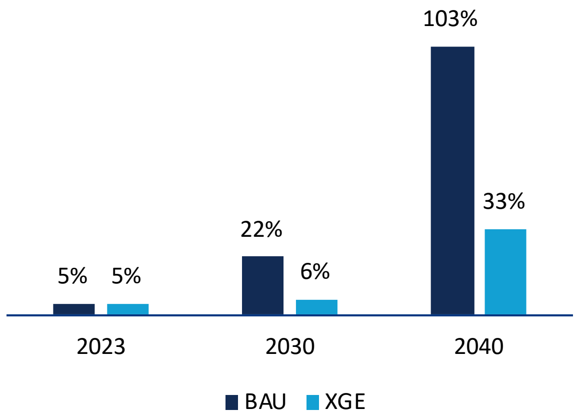
[6] Unity in power, power in unity: why the EU needs more integrated electricity markets (Bruegel)
[7] Energy and climate transition: How to strengthen the EU's competitiveness (2024). A study for BUSINESSEUROPE. Energy and climate transition: How to strengthen the EU's competitiveness - Reboot Europe and Energy and climate transition: How to strengthen the EU's competitiveness – Re-boot Europe

The economic cost of an unreliable electricity grid

Delaying investments in a stable and reliable electricity grid has far-reaching consequences, particularly for electricity costs borne by consumers. Without timely upgrades, grid inefficiencies lead to rising congestion, increased reliance on countertrading and redispatching and ultimately higher electricity prices. These costs are initially covered by transmission system operators (TSOs) but are eventually passed on to consumers through network tariffs, making grid-related inefficiencies a significant factor in electricity price volatility. In 2019, congestion costs in Germany amounted to EUR2.5bn, contributing to an electricity price increase of EUR2.32 per MWh, which represented 4.6% of the average monthly wholesale electricity price that year. If grid expansion remains limited under a business-as-usual (BAU) scenario, congestion costs are projected to rise sharply, reaching EUR12.3bn by 2030 and EUR56.7bn by 2040. In contrast, under a strong grid expansion scenario (XGE), the increase in congestion costs is expected to be more moderate, reaching EUR3.4bn in 2030 and EUR18.2bn in 2040 (Figure 5a). For simplicity, we assume that these congestion costs will be absorbed linearly into the final electricity price in Germany, leading to different levels of price shocks compared to a baseline scenario in which no additional congestion costs occur. These impacts are illustrated in Figure 5b. Depending on the grid expansion scenario, either business-as-usual (BAU) or strong grid expansion (XGE), electricity price shocks are projected to vary significantly. In 2025, price increases are estimated at +5%. By 2030, they are expected to reach +22% under the BAU scenario and +6% under the XGE scenario. By 2040, the disparity widens further, with price shocks reaching +103% in the BAU scenario and +33% in the XGE scenario. These electricity price shocks account solely for congestion costs and do not factor in potential savings from more affordable renewable energy sources.

Figure 5: Evolution of the annual redispatch costs in Germany (Figure a, in EUR mn) and implied potential electricity price increase (Figure b, in %)

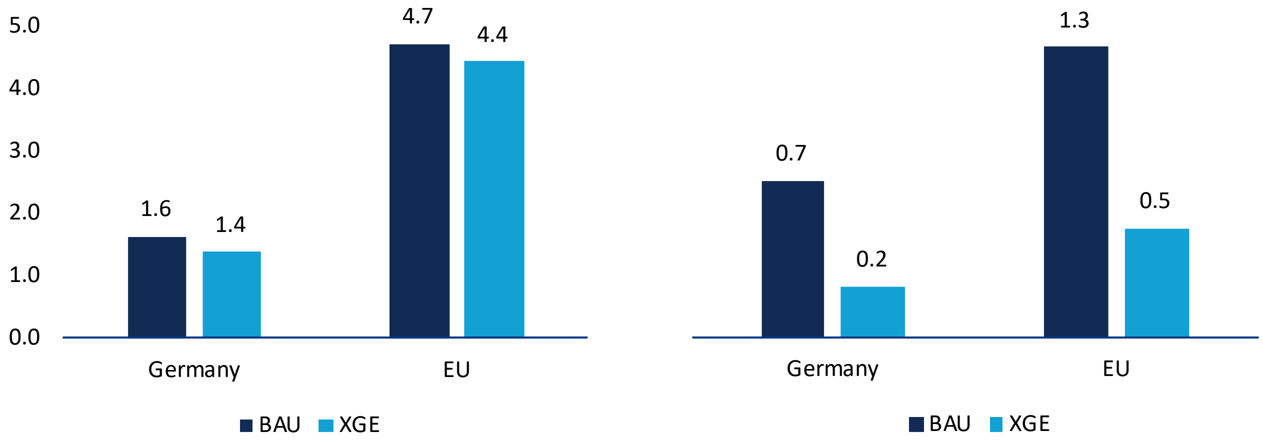




Sources: JRC, Allianz Research

Electricity congestion is more than just a technical challenge. It also poses potential economic risks. Our modeling, which focuses on grid congestion costs while abstracting potential gains due to factors like cheaper renewable energy, highlights the significant economic consequences of failing to take decisive action to expand and modernize the grid. Under a business-as-usual (BAU) scenario with only limited grid expansion, Germany could face cumulative GDP losses of EUR1.6trn by 2050 (Figure 6a), while the EU as a whole could suffer economic losses reaching EUR4.7trn. Even with a more ambitious grid expansion (XGE), economic losses remain substantial: EUR1.4trn in Germany and EUR4.4trn across the EU, driven by persistently high electricity prices. Moreover, the indirect economic costs of an unreliable grid far outweigh the direct financial burden of congestion itself (Figure 6b). In Germany, direct congestion costs under BAU are projected at EUR0.7 trn, but the broader economic impact on GDP is more than twice that amount. A similar pattern emerges at the EU level, where direct congestion costs of EUR1.3trn translate into an economic loss of EUR4.7 trn. Even with extensive grid expansion, congestion costs could be reduced to EUR0.2 trn in Germany and EUR0.5 trn in the EU, but GDP losses would still remain significant. The message is clear: failing to expand and modernize the electricity grid is not just about higher electricity prices; it threatens economic stability and competitiveness. Our findings underscore that the energy transition and grid expansion must go hand-in-hand to ensure a resilient and prosperous future. However, even with a substantial expansion of grid infrastructure, other measures will be required to make demand more flexible and reduce congestion in a future electricity market dominated by renewables.

Figure 6: Economic loss from electricity market congestion in Germany & the EU (2025 – 2050, EUR trn): GDP loss (a) and direct congestion costs (b)

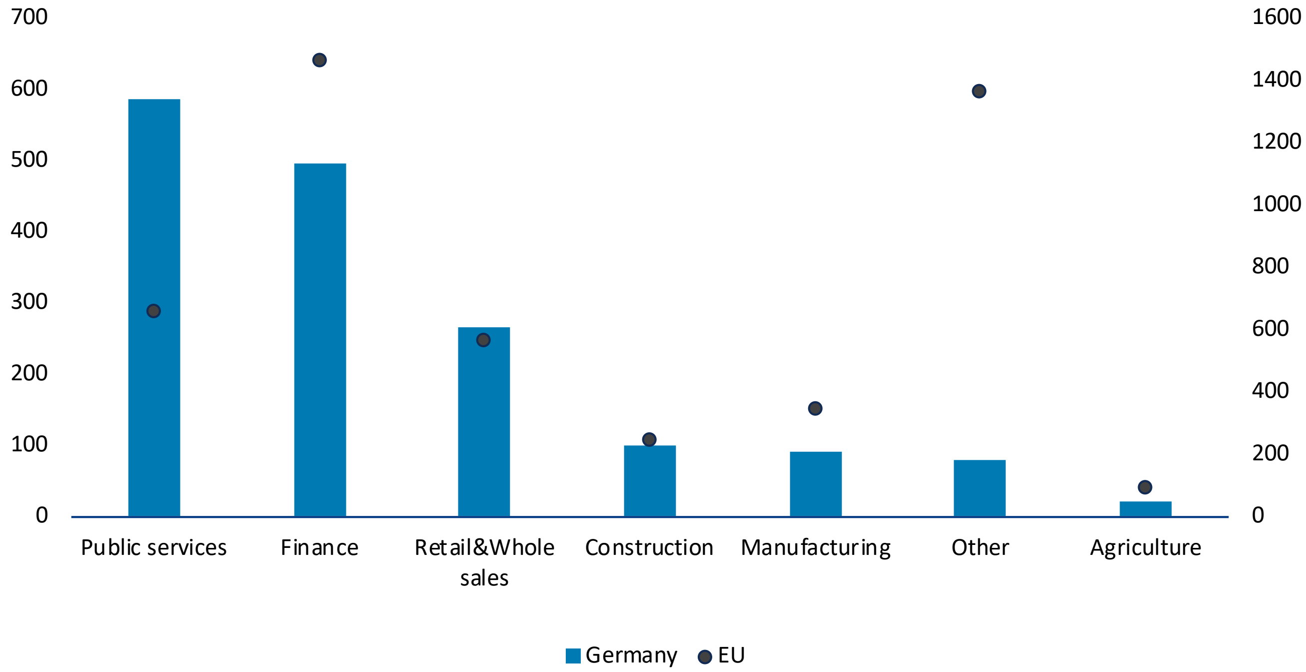


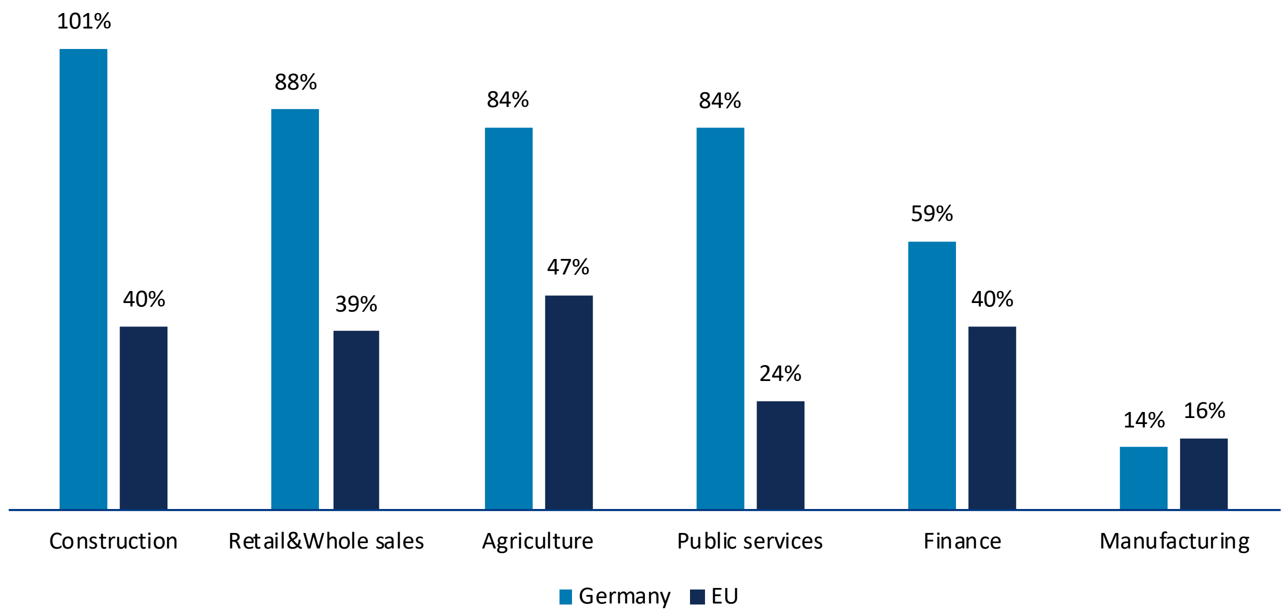
Sources: Oxford economics, Allianz Research

The economic impact of electricity congestion is not felt equally across sectors; some industries are far more exposed than others (Figure 7). Public services, finance and retail and wholesale trade will bear the greatest burden in both Germany and the EU. In Germany, public services are projected to accumulate losses of around EUR585bn from 2025 to 2050 (84% of the sector value added in 2025), making it the most affected sector. The finance industry is not far behind, facing losses of EUR495bn due to its high sensitivity to electricity price fluctuations (59% of the sector value added in 2025). The banking sector, for instance, could see a direct impact on both returns on assets and returns on equity, making grid instability a significant financial risk.[8] Retail and wholesale trade, which is central to supply chains and consumer markets, would also be significantly impacted, with losses of EUR266bn (88% of the sector value added in 2025). Construction and manufacturing are not spared either, with expected losses of EUR99bn and EUR90bn, respectively, representing more than 100% of 2025 value added for the construction sector and 14% for manufacturing. At the EU level, the finance sector stands out with an enormous projected loss of EUR1.46trn, almost three times the hit seen in Germany alone, representing 40% of its value added in 2050. Public services follow with losses of EUR654bn, while retail and wholesale trade is expected to lose EUR566bn. Finally, manufacturing and construction, key pillars of the European economy, also face significant losses of EUR340bn and EUR243bn, respectively.

[8] Energy shocks and bank performance in the advanced economies - ScienceDirect

Figure 7: Sectoral value added loss from electricity congestion in Germany & the EU: (a) total cumulative loss in EUR trn for the period 2025 – 2050; (b) total cumulative (2025 – 2050) loss relative to sectoral value added in 2025

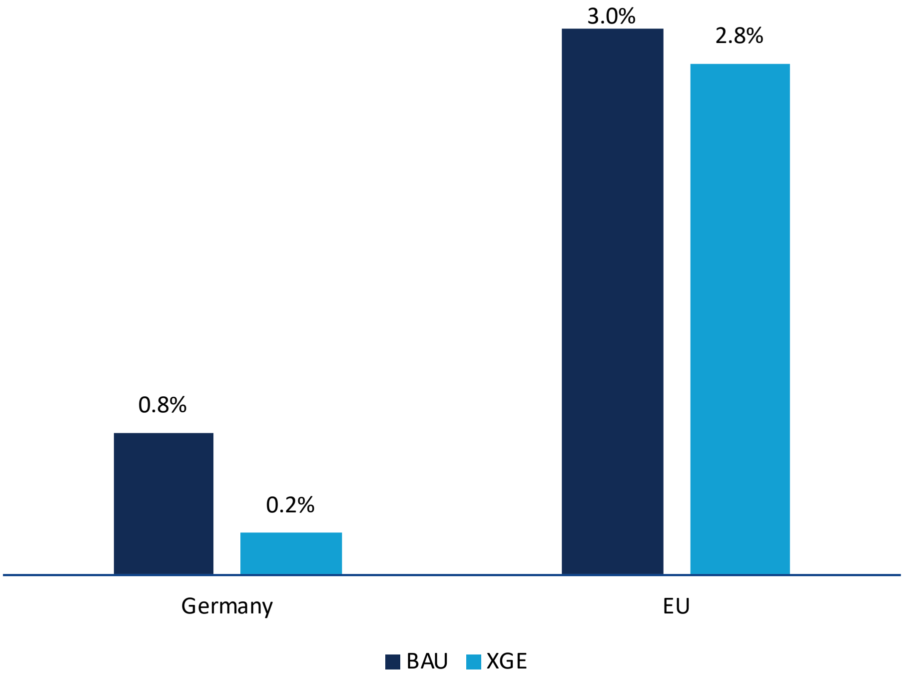




Sources: Oxford economics, Allianz Research

Electricity congestion directly affects production prices, making goods and services more expensive and undermining competitiveness. Figure 8 illustrates the impact of electricity congestion on production costs in Germany and the EU, with significant disparities between a business-as-usual (BAU) scenario and a strong grid expansion (XGE) scenario. In Germany, electricity congestion is expected to drive up production costs by +0.8% under the BAU scenario, whereas under the XGE scenario the increase is limited to just +0.2%. While these percentages may seem small, they can have far-reaching consequences, particularly for energy-intensive industries such as manufacturing and construction. Higher production costs make German goods less competitive on international markets, potentially shifting industrial activity to regions with more stable and efficient electricity infrastructure. At the EU level, the impact is even more pronounced, with production costs rising by +3.0% under BAU and +2.8% even with a more ambitious grid expansion. This suggests that congestion-related inefficiencies in Germany are not just a German problem but a broader European challenge. As energy costs continue to shape industrial competitiveness, regions with constrained grids will face increasing pressure from global competitors with more reliable and cost-effective energy systems. Therefore, the failure to invest in grid expansion will make European industries more vulnerable to price volatility, reducing their ability to compete globally.

Figure 8: Impact of electricity congestion on production costs in Germany & the EU (average 2025 – 2050)



Sources: Oxford economics, Allianz Research

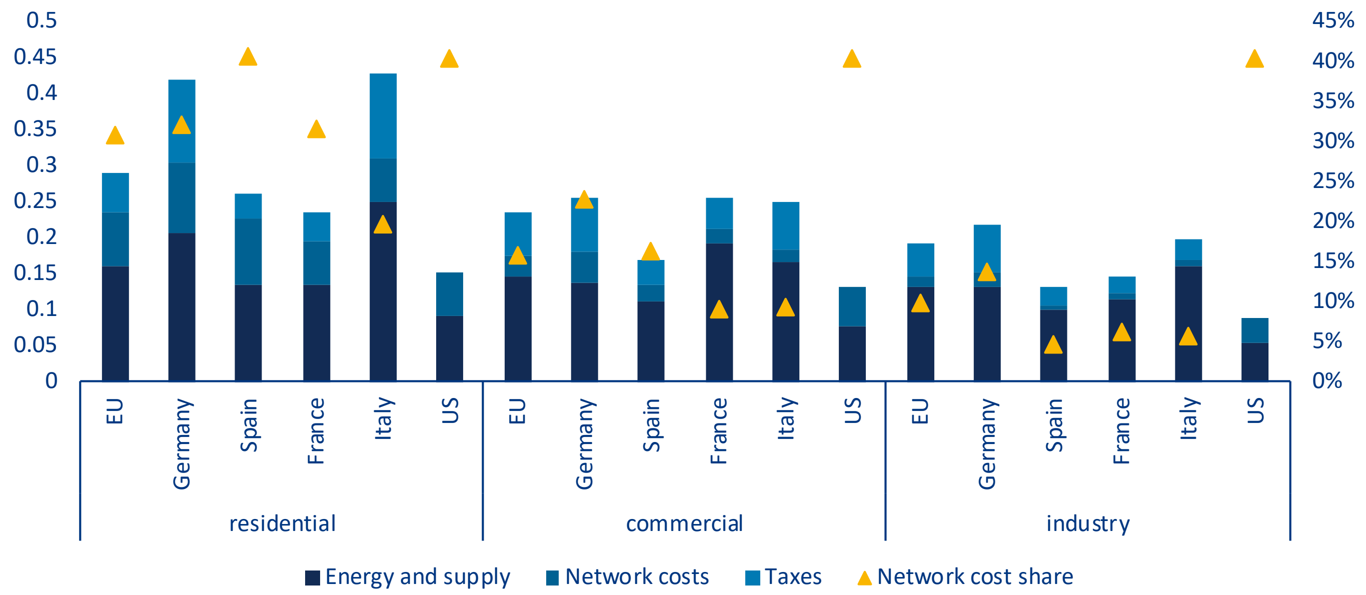
Implications for electricity prices

To maintain competitiveness and minimize the economic burden on both households and industries, it is crucial to assess the implications of the network transition on electricity prices and take measures to limit price increases. The additional investments required for developing new generation capacities and expanding the associated network infrastructure further strain Europe's already high electricity prices. Network investments alone are projected to increase grid costs by +25% until 2030 and up to +60% by 2050 compared to 2022 levels.[9] Additionally, electricity generation costs are likely to increase as investments in energy generation will need to double, reaching EUR93bn annually to meet Europe's Fit-for-55 emission reduction targets.[10] On the other hand, lower generation costs of wind and solar have the potential to decrease electricity prices in the mid to long-run, with potential price declines of -11% by 2035 and -30% until 2040 in a net-zero scenario. This discrepancy between immediate cost increases and long-term gains warrant measures to distribute the current financial burden of the transition to future generations that are reaping more of the benefits. Debt-based financing by governments and a prolonging of refinancing periods for grid investments could help to smooth out the price path for consumers.

Given the existing fragmentation in Europe's electricity system, it is worth examining the country-specific factors determining electricity prices (Figure 9). In terms of price differentials and compositions, different types of consumers in different countries are facing vastly different electricity costs. Of Europe's major economies, Germany and Italy recorded the highest average electricity prices for households in 2023. Some of this price differential can be attributed to higher generation costs that are 17% and 41% above the European average, respectively (20 cents/kWh for Germany and 24 cents/kWh for Italy). However, the most important factor is electricity taxation, which adds about 38% or 11 cents/kWh to the base costs. As expected, network charges are more elevated in countries such as Germany and Spain, with a higher share of renewables in their respective electricity mix. But until now, they were not the central factor reducing price competitiveness. With a slower transition to renewables, the US shows lower generation costs but a relatively high share of network costs (40% for households). Electricity taxes in the US are state-specific but would only add 7-10% to the price, keeping overall costs to consumers below European levels. Commercial and industrial consumers face lower prices across the board, even though prices in Germany are higher than in the other major economies of the EU. Interestingly, network charges paid by industrial consumers are very low in Europe. This means that the proposed lowering of network charges recently discussed in the German elections would likely do little in terms of improving industrial sector competitiveness.

[9] 2024 Monitoring Report (ACER)
[10] European Commission

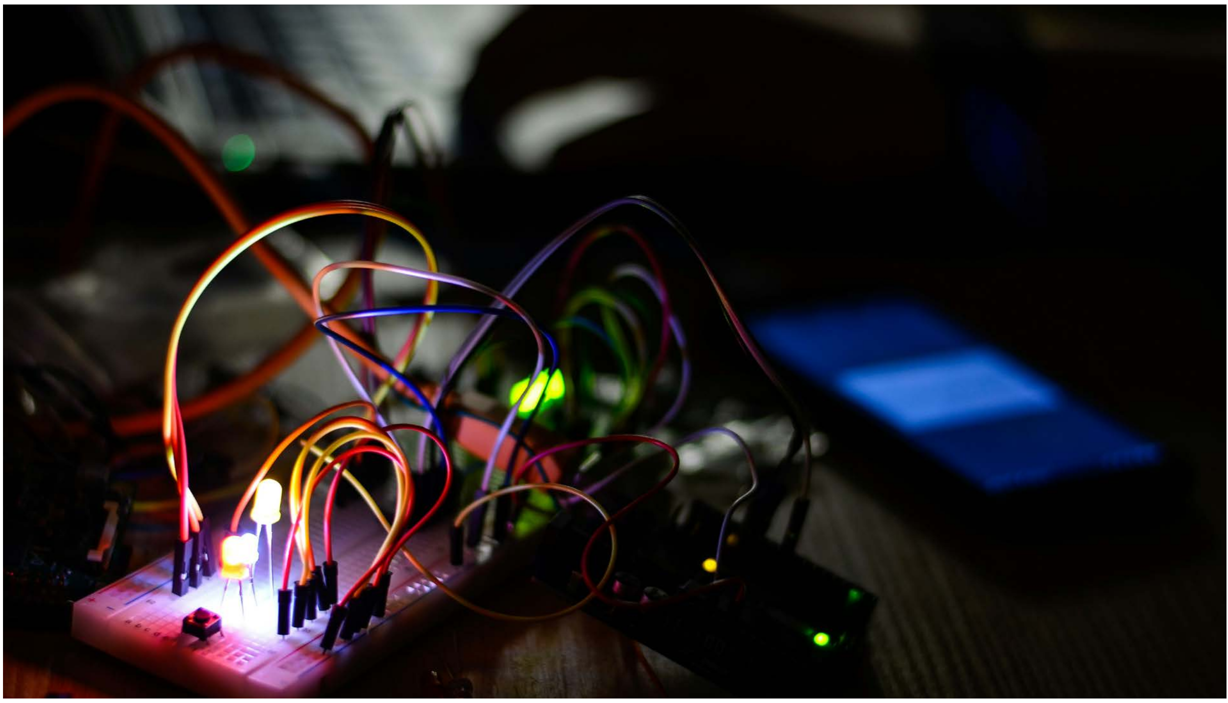
Figure 9: Decomposition of electricity prices in Europe & US in 2023 (EUR/kWh, lhs) and share of network cost in the price relative to total cost of electricity provision (%, rhs)



Sources: Eurostat, EIA, Allianz Research

Lowering electricity prices for consumers requires a combination of short-term measures and long-term structural reforms to reduce system costs. In the short term, targeted policy interventions, such as reducing electricity taxation, optimizing network tariffs, and enhancing retail market competition, can provide immediate relief to households and businesses. Additionally, market design improvements, such as strengthening Power Purchase Agreements (PPAs) and expanding the use of Contracts for Difference (CfDs), can help stabilize prices for consumers while de-risking investments for electricity suppliers. However, achieving sustained price reductions requires addressing structural cost disparities in the energy system. While the continued expansion of renewables can lower electricity generation costs, these benefits will only materialize if they are supported by investments in grid infrastructure and system efficiency. The EU's new Action Plan on Affordable Energy marks an important first step in tackling these challenges, outlining targeted measures to reduce energy costs, improve market integration, and accelerate investments in renewables and grid infrastructure.[11]

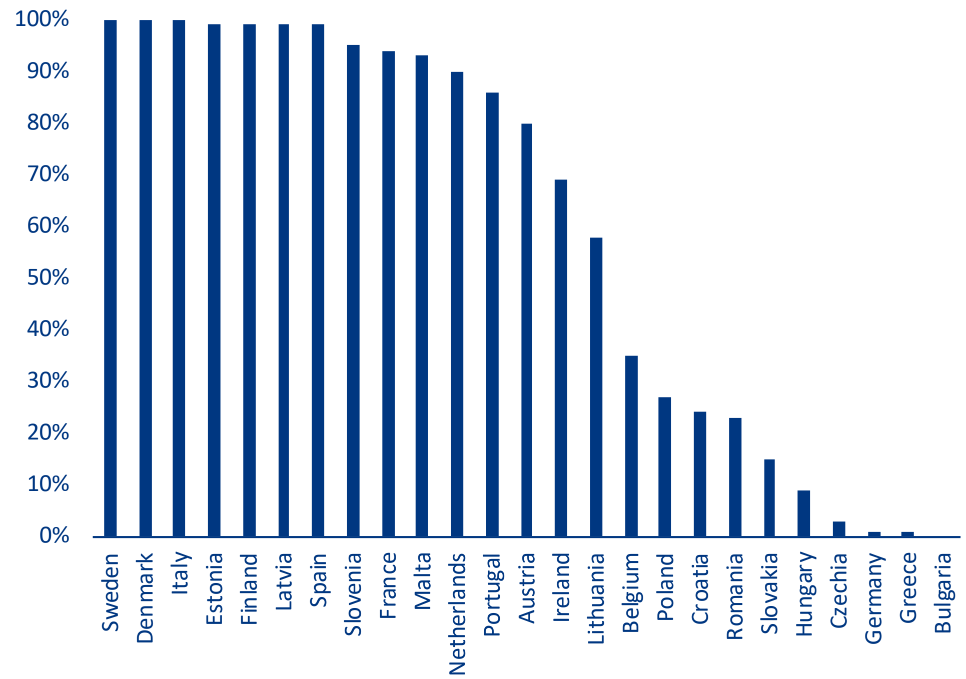
[11] Action Plan for Affordable Energy



Optimizing the energy transition: Cutting costs through smart solutions

To reduce the economic burden and maximize the gains of the electricity sector transition, it is necessary to go beyond the grids and focus on improving system efficiency. Promoting greater demand-side flexibility could play a key role in improving system stability while reducing the need for oversizing grid infrastructure. If consumers spread their electricity consumption better throughout the day, this reduces the need for storage infrastructure and decreases the peak-load, helping to ease the strain on the grid. While electricity demand is not fully flexible, a significant portion – around 30%, according to the Energy Transitions Commission (ETC) – could be shifted to better align with supply. The development of smart grids, coupled with the widespread rollout of smart meters, enables real-time monitoring of electricity usage, improving load balancing and empowering consumers to adjust their consumption based on dynamic pricing signals, such as time-of-use tariffs. This not only enhances grid efficiency but also helps consumers manage their energy use more effectively and reduce their electricity bills. According to European Commission estimates, households equipped with smart meters reduce their energy consumption by 2-10% and can achieve average cost savings of EUR270. Because of these benefits, smart meter adoption has grown significantly across Europe, with over 90% penetration in 12 countries (Figure 10). However, gaps remain in Germany and many Eastern European nations, where adoption lags, limiting potential system-wide efficiency improvements. A further increase in smart meter usage paired with increased monitoring and AI-based demand optimization could help to lower infrastructure needs and reduce costs for consumers in high price regions such as Germany, Poland or Czechia.

Figure 10: Smart meter roll-out in selected European countries (% share of consumers)



Sources: Allianz Research, ACER Monitoring Report 2024

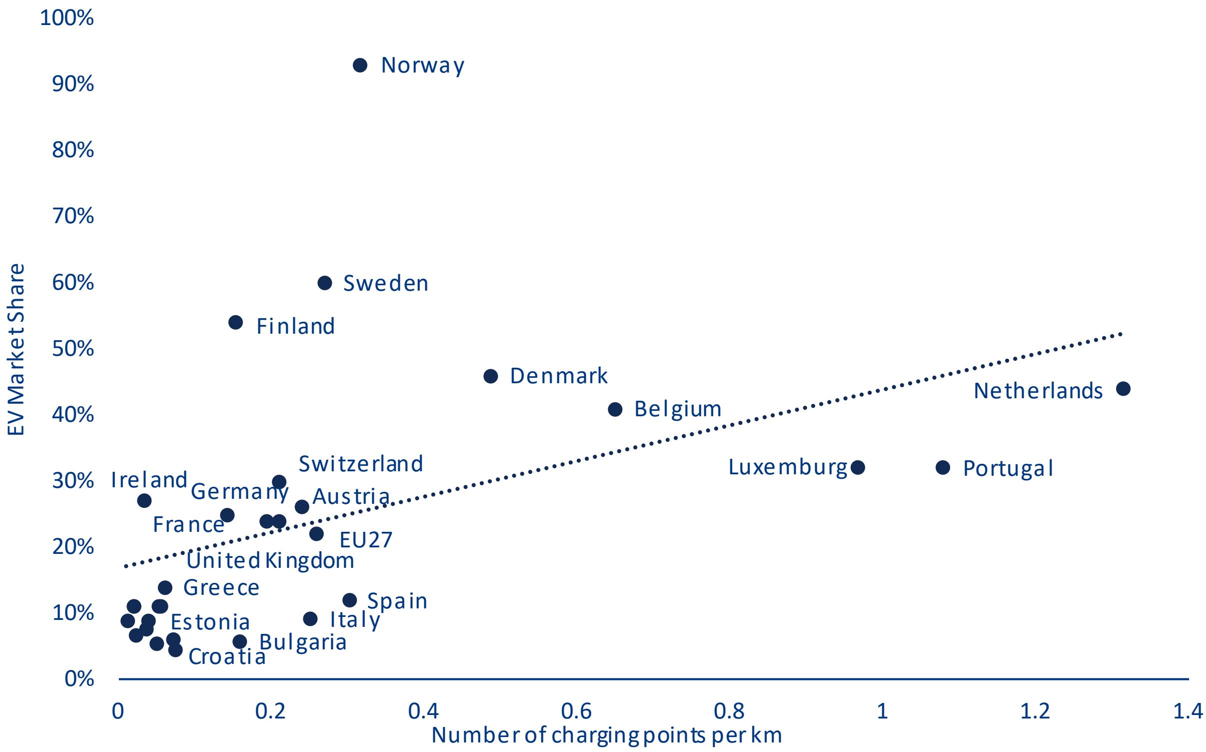
Further efficiency improvements can come from a better integration of the energy sector with major downstream consumers like buildings, industry or transportation. These sector coupling approaches not only lower system costs but also accelerate the decarbonization of high-emission industries, creating a more flexible and sustainable energy landscape. A key strategy involves aligning sector demand with electricity supply through power-to-X transformation technologies. In this approach, surplus renewable electricity is converted into downstream energy carriers like heat or hydrogen, or directly used in industrial processes, preventing costly curtailment while enhancing energy security. This not only balances grid load and stabilizes electricity prices but also unlocks new pathways for decarbonization. For example, Germany curtailed 10 TWh of renewable electricity in 2023. Had this energy been used to produce green hydrogen, it could have covered approximately 12% of the country's hydrogen demand, translating to 6.6 TWh of hydrogen energy – without incurring additional costs.[12] This illustrates the untapped potential of surplus electricity, which, if harnessed effectively, could play a crucial role in Europe's clean-energy transition.

Given the increasing electricity demand from electric vehicles, achieving a successful transition to a low-carbon electricity market will depend on an efficient transition of the transport sector. On the one hand, a continued expansion of the electric vehicle (EV) fleet in Europe will add to electricity demand, increasing final electricity consumption by around +6.7% until 2030 and +19.4% by 2040, if emission-reduction targets are realized.[13] This will intensify existing challenges in the electricity market as significant additional renewable-generation capacity will be needed to accommodate the growing demand while ensuring continued emission reductions in the sector. On the other hand, EVs present a major opportunity for grid balancing by providing additional storage capacity through bi-directional charging technology. If widely adopted, EV batteries could enhance grid stability by absorbing excess energy during periods of high supply and releasing stored power when demand peaks. Their geographical dispersion could also make them more beneficial to the energy system than centralized grid storage as they are more concentrated around urban demand hubs, where electricity consumption is highest. This proximity

[12] This calculation assumes 50 kWh of electricity per kg of hydrogen for production and 33 kWh/kg for conversion back to power.
[13] Eurelectric

to end users helps reduce transmission losses, ease grid congestion and enhance local energy resilience. It would also help to reduce Europe's greenhouse gas emissions by around 255 MtCO2 or 7% of the total emissions in 2023.[14] However, beyond cost reductions for EVs, increasing their adoption in Europe's vehicle fleet will also require a further expansion of public charging infrastructure. Geographic factors, such as country size and urbanization levels, along with technical aspects, including charging speed, grid capacity and the driving range of EV batteries, will be key in determining the scale of the required infrastructure. The experience of Scandinavian countries like Finland, Sweden and Norway demonstrates that a high EV market share can be achieved even with a moderate density of public charging points, ranging from 0.15 to 0.3 per kilometer of road network (Figure 11). As battery-electric vehicles (BEVs) become more widespread and battery ranges improve, the optimal density of public charging infrastructure is likely to stabilize around 0.05 to 0.1 charging points per BEV, ensuring sufficient accessibility while optimizing investment efficiency.[15]

Figure 11: EV market share and charging points per km by country



Sources: Allianz Research, IEA, EAFO, Eurostat

[14] EEA
[15] SAMEpath (Transport section) based on the analysis by FfE

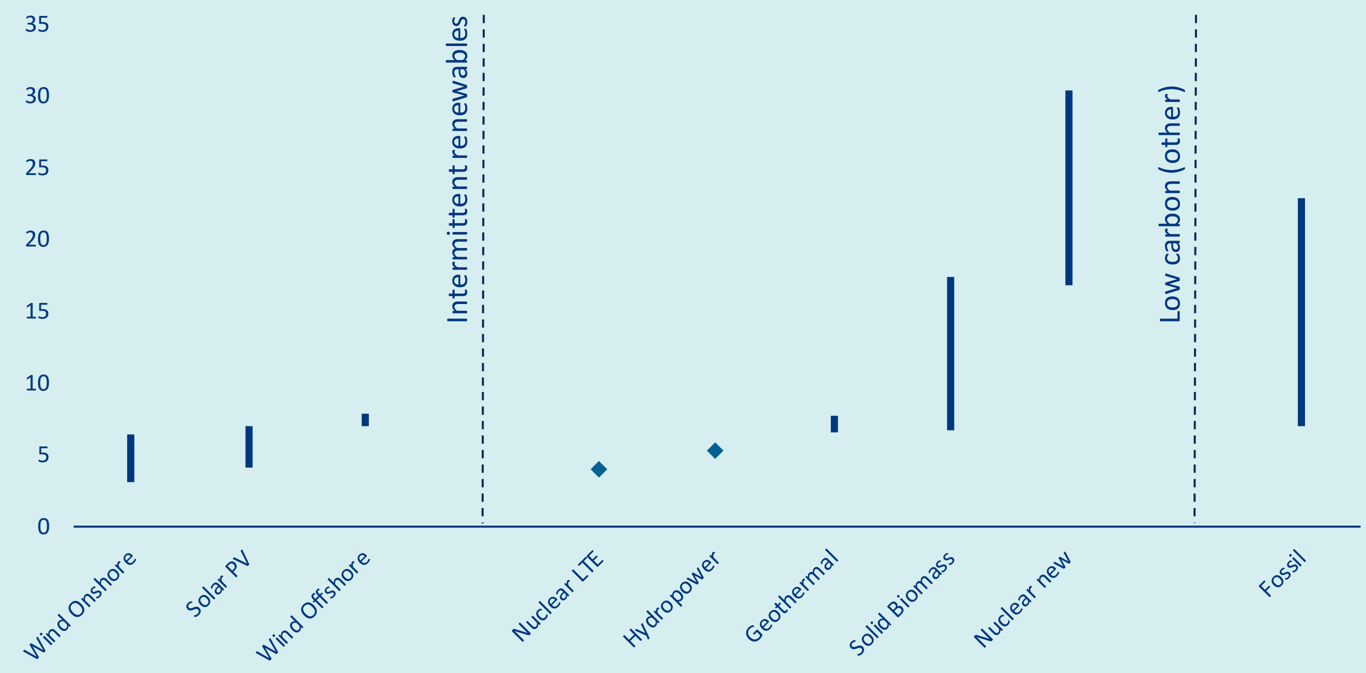
Reducing system costs with low-carbon baseload energy sources

While wind and solar are essential for achieving energy-transition targets, they are not the only sources of low-carbon electricity. Other technologies, such as geothermal, hydropower, biomass and nuclear, also offer low-emission power while providing more stable baseload electricity. The advantage of these complementary green energy sources lies in their predictable energy flows and, in many cases, greater deployment flexibility. This reduces the need for extensive infrastructure and storage investments, ultimately lowering overall system costs. However, they also present challenges, including higher generation costs, import dependencies, feedstock availability and geographical constraints.

When available, hydropower is one of the most cost-efficient generation technologies, with a Levelized Cost of Electricity (LCOE) of approximately 5.3 cents per kWh, making it competitive with wind- and solar-based electricity production (Figure 12). Given its affordability and reliability, several European countries with abundant hydropower resources, such as Norway and Sweden, use it for a significant share of their electricity generation – 43.3% and 12.1%, respectively. However, its potential is inherently limited by geographical constraints, environmental considerations and the need for large-scale infrastructure, making it a highly valuable but regionally dependent energy solution. Hydropower is also not immune to the effects of climate change as declining water availability can lead to drops in electricity output. When this occurs, countries may be forced to ramp up fossil-fuel-based generation to compensate, as seen in India and New Zealand in 2024. This underscores the risk that over-reliance on hydropower could delay the phase-out of fossil-fuel-based electricity, particularly in regions where water scarcity is becoming more frequent due to climate change.

Geothermal energy production also comes at a comparatively low LCOE of around 7 cents/kWh, making it a competitive low-carbon energy source. However, the technology is not yet widely deployed due to its geographical limitations, high upfront investment costs and exploration risks. Viable geothermal power generation requires high-temperature reservoirs, which are mostly found in tectonically active regions, which somewhat restricts its accessibility. While advancements in Enhanced Geothermal Systems (EGS) could help expand its potential and have recently seen promising cost declines[16], the technology is still in its early stages and not yet commercially viable on a large scale. However, with projected declines in construction costs of around -30% by 2050 and up to -70% in the long term, EGS have the potential to become a viable complementary source for low-carbon electricity.

Figure 12: Levelized cost of electricity by technology (in Cent/kWh)



Sources: Allianz Research, Fraunhofer ISE, IRENA, Lazard, BNEF. Note: Ranges depict differences in averages of reviewed sources.

[16] Fervo

Nuclear power is another baseload power source, offering stable, around-the-clock electricity that helps mitigate the intermittency of wind and solar. The technology has recently seen increasing support, particularly from emerging demand sources such as AI, data centers, and high-performance computing that require continuous and grid-independent power. Unlike renewables, which depend on weather conditions and require significant storage solutions, nuclear provides a constant energy supply without fluctuations. This makes it particularly attractive for large tech companies seeking to secure dedicated, uninterrupted power for AI-driven workloads. While lifetime extensions of existing nuclear plants offer a highly cost-effective solution at around 4 cents/kWh, new conventional large-scale reactors remain expensive due to high upfront costs, long construction times and frequent budget overruns. Additionally, as most ongoing nuclear projects are first-of-a-kind, even for conventional designs, nuclear is the only electricity source that has seen a substantial increase in LCOE, up by +55% over the past decade. Small Modular Reactors (SMRs) have emerged as a potential alternative, promising lower capital costs, faster deployment and enhanced scalability. However, they are still at an early stage and have seen cost increases as well, making them substantially more expensive when it comes to power generation than intermittent renewables. Beyond economic factors, nuclear energy also faces challenges related to waste disposal, reliance on uranium imports and security concerns, making it a highly debated issue in several countries. While cost reductions could enhance its role as a stabilizing force in the low-carbon electricity market, its viability largely depends on existing nuclear infrastructure and waste-management systems. Countries with established nuclear industries are better positioned to benefit, whereas nations without such frameworks may face high opportunity costs in building them from scratch. Although nuclear energy will remain part of the global electricity mix, the IEA projects that its share will decline to just 8% by 2050 in a net-zero scenario, underscoring its limited role compared to the expanding deployment of renewables.

Another strategy to improve system efficiency in Europe's electricity market involves reforming market design by restructuring bidding zones. Currently, electricity prices in Europe are often set for large bidding zones that follow national borders rather than reflecting actual transmission bottlenecks. This misalignment can distort price signals, hinder renewable integration and increase system inefficiencies. A key issue is that a single price zone, such as Germany, creates incentives for local overproduction in areas with high renewable generation while demand centers in other regions cannot directly access the cheap electricity due to grid bottlenecks. If transmission capacity were sufficient, this would not be a problem, but where infrastructure is lacking, congestion costs rise significantly. At the same time, these distorted price signals affect capacity expansion, leading to suboptimal decisions for new generation and storage investments as grid management costs are not fully considered. Introducing smaller bidding zones – as currently assessed in the European bidding zone review – would help internalize system costs into electricity prices, reduce the need for oversized grid expansion, and improve locational investment signals. Additionally, better-aligned pricing zones could optimize cross-border electricity flows, supporting the faster integration of the European electricity market.

However, redefining bidding zones would likely lead to higher electricity prices in certain regions that have historically benefited from lower wholesale prices due to large price zones covering diverse grid conditions. In Germany, this would particularly affect the south, where major industrial hubs are located but renewable energy capacity lags behind. If the country were split into separate northern and southern bidding zones, electricity prices in the south could increase by EUR5-9/MWh compared to the north, potentially putting cost pressure on industrial production in the region.[18] To prevent excessive short-term price shocks, transitional measures such as temporary financial compensation mechanisms, phased price adjustments or targeted investment support for affected industries could help smooth the transition and maintain competitiveness.

[18] Aurora Energy Research

From tensions to solutions: Addressing price disparities in market integration

Some difficulties need to be managed to ensure that the overall gains of further integration through additional interconnector capacities are distributed fairly. One issue is to ensure some level of energy autonomy for each country for scenarios where the integrated system cannot deliver enough electricity. It is also important to find solutions for energy producers as a more integrated electricity market means more competition, which can force unprepared energy companies operating at high costs out of the market. Finally, there is also the question of energy prices and the problem that while an integrated system would yield lower prices in importing countries, it would also mean that consumers in countries where electricity production is cheaper would face higher comparative prices. This could lead to tensions as countries that have invested heavily into renewable generation, leading to (long term) lower prices, might not reap all the benefits, resulting in conflicts over possible compensations and (unfair) subsidy schemes. This concern is underscored by the recent cancellation of the Hansa Power Bridge interconnector by the Swedish government due to fears of increased energy prices in southern Sweden and instability in Sweden's power market.

A surcharge on electricity exports could fund a subsidy mechanism to ensure welfare gains in both the exporter and importer country. This would be an alternative solution to an additional European level funding scheme that supports renewable energy generation where it is efficient, such that the burden of investing into the new infrastructure is shared among different European nations. The option suggested here would be the inclusion of a surcharge and subsidy mechanism on the electricity price itself. It would add a surcharge on the electricity price that is exported via the additional interconnector capacity that is built and distribute the revenues to the exporter country electricity customers to offset their electricity price increase from the consequently higher market integration. This option has the advantage that it could be implemented bilaterally and tailored to the impacts of specific bilateral interconnector extensions. This will be exemplarily analyzed for the mentioned Hansa Power Bridge (Figure 13). Though the failure of this project could have been already avoided through properly managed pricing zones within Germany, as Sweden demanded a differentiation in North German and a South German pricing zone, which would have alleviated the impacts of German electricity price fluctuations on the Swedish electricity market.[19]

Figure 13: Hansa Power Bridge interconnector proposal between Germany and Sweden

Source: 50Herz

[19] SKGS says no to Hansa Power Bridge

To analyze the impact of additional interconnection capacity between Sweden and Germany on the electricity markets, and to determine beneficial support policies, we use the EUREGEN power market model.[20] For the purpose of this analysis, the model simulates hourly electricity prices in Europe, with production and consumption depending on representative external drivers like weather patterns. The analysis is focused on the year 2030 and examines three different interconnection capacities, namely today's 0.6GW, an extension with the Hansa Power Bridge to 1.3GW and an economically optimal extension to a total of 3.6GW (Row [A] Table 2). The remaining European electricity infrastructure as well as the external conditions remain identical for the analysis of all three cases.

Table 2: Analysis of the expansion of interconnector capacity between Germany and Sweden[21]

		Current	With Hansa Power Bridge	Optimal Capacity
[A]	2030 interconnector capacity between Germany and Sweden	0.6 GW	1.3 GW	3.6 GW
[B]	Electricity exports Sweden to Germany TWh	5.27 TWh	11.25 TWh	30.44 TWh
[C]	Electricity exports Germany to Sweden TWh	0.03 TWh	0.08 TWh	0.34 TWh
[D]	Needed surcharge on additional exports to finance electricity price increase offsetting subsidy in exporting country	0.00 Ct/kWh	4.60 Ct/kWh	3.70 Ct/kWh
[E]	Total value of offsetting subsidies annually	EUR 0.00 bn	EUR 0.27 bn	EUR 0.93 bn
[F]	Total annual value of price difference of electricity trade between Germany and Sweden	EUR 0.20 bn	EUR 0.41 bn	EUR 0.95 bn
[G]	Average wholesale electricity price Germany EUR Ct/kWh without surcharge/subsidy scheme	8.73 Ct/kWh	8.70 Ct/kWh	8.57 Ct/kWh
[H]	Average wholesale electricity price Sweden EUR Ct/kWh without surcharge/subsidy scheme	5.12 Ct/kWh	5.34 Ct/kWh	5.79 Ct/kWh
[I]	Average wholesale electricity price Germany EUR Ct/kWh with surcharge/subsidy scheme		8.73 Ct/kWh	
[J]	Average wholesale electricity price Sweden EUR Ct/kWh with surcharge/subsidy scheme		5.12 Ct/kWh	
[K]	Annual reduction in electricity production costs / gain electricity producers (Total Germany and Sweden)	EUR 0 mn	EUR 30 mn	EUR 186 mn

[20] Mier, Mathias, European Electricity Prices in Times of Multiple Crises (2024). Available at SSRN: https://ssrn.com/abstract=4936684 or http://dx.doi.org/10.2139/ssrn.4936684
[21] Calculations based on Mathias Mier, ifo Institut, with EUREGEN-Modell (Mier, 2024)

Rows [B] and [C] indicate that exports primarily flow from Sweden to Germany, largely in proportion to interconnector capacity. The additional capacity lowers average wholesale electricity prices in Germany (Row [G]) while raising prices in Sweden (Row [H]). Although the price differences appear small, they reflect the impact of a single interconnector expansion and would scale with additional expansions. Moreover, the table does not capture the broader benefits for other European countries. In this analysis, price changes are offset through a surcharge applied to additional exports on an hourly basis. The revenue from this surcharge is redistributed as a subsidy to exporters, effectively stabilizing electricity prices. The surcharge is calculated as:

$$\boldsymbol{total\ hourly\ surcharge} = surcharge\left(\frac{Ct}{kWh}\right) * \max(0, hourly\ export\ (GWh) - 0.6GW) * 1000$$

Row [D] shows that a surcharge of 3.7–4.6 Ct/kWh on additional exports beyond the 0.6 GW current interconnector capacity would be required to finance the subsidy of EUR0.27bn for the 1.3 GW expansion and EUR0.93bn for the 3.6 GW interconnector capacity (Row [E]). While, in principle, these transfers could be funded through the revenues generated by price differentials from electricity trade (Row [F]), these revenues are already allocated through an established distribution mechanism.[22] After applying the surcharge and subsidy, prices are equalized again, as shown in Rows [I] and [J]. For this analysis, the resulting gains are allocated to electricity producers, though alternative distribution models could be considered. The total annual savings in production costs for electricity producers are presented in Row [K]. However, it is important to note that these savings primarily stem from cost reductions for German electricity producers. The EUR30bn in annual savings from the Hansa Power Bridge interconnector expansion should be viewed in relation to the EUR0.6bn expected cost of construction. Expanding interconnector capacity to an optimal 3.6 GW would increase annual savings to EUR186bn, significantly improving the speed of investment recovery.

[22] See SMARD, Epex Spot, Nord Pool and Monopolkommission

The grid of tomorrow: Financing options and market solutions

Amidst fiscal tightening and growing military spending needs in Europe, doubling grid infrastructure investments to reach the required EUR2.3trn by 2050 will be a significant challenge. Several European countries are already grappling with fiscal deficits well above 3% of GDP – France at 6.1%, Italy at 3.8% and Poland at 5.8% – while Germany's debt brake further constrains investment options. Bridging the EUR30-50bn annual investment gap solely through increased public financing may therefore not be feasible. Additionally, the potential retreat of US military support might require Europe to double its military spending, reaching 3.5% of the region's GDP, and thus increasing annual spending by more than EUR250bn.[23] Given these financial pressures, Europe must adopt innovative strategies to distribute high capital costs more effectively over time, and unlock underutilized private funding sources.

A crucial first step toward increasing infrastructure investments is to enhance investment conditions at the European level. This requires harmonizing regulatory frameworks across countries to create a more predictable and efficient environment for investors. Additionally, strengthening existing funding instruments, such as the Connecting Europe Facility (CEF), and establishing a dedicated funding pool for grid infrastructure would help mobilize capital and ensure long-term financing. To attract private investment, fiscal support measures – including subsidies and guarantees – can help de-risk projects and incentivize capital allocation toward critical infrastructure. Given that projects like interconnectors often have construction timelines exceeding 10 years, it is essential to streamline approval processes and ensure the timely disbursement of funds to avoid delays and cost overruns. At the same time, advancing the Capital Markets Union (CMU) is

[23] Bruegel

key to improving access to diversified funding sources. By deepening Europe's financial markets and reducing fragmentation, the CMU can facilitate greater private sector involvement in infrastructure financing, enabling more efficient capital flows and reducing reliance on public funding.

To accelerate the integration of European electricity markets, another option is the creation of an Independent System Operator (ISO) akin to the US.[24] An ISO would oversee the operation of transmission networks across multiple countries, ensuring non-discriminatory access to the grid, optimizing cross-border electricity flows and improving market efficiency. Unlike national TSOs, which both own and operate their respective grids, an ISO would act as an independent entity, coordinating system operation without owning transmission assets. This would enable a more top-down approach to system planning that is likely better suited to weigh system-wide benefits vs domestic interests than the current bottom-up planning conducted by various local TSOs. With a focus on the interconnection needs, an ISO could coordinate investment efforts between the public and private sector, leading to a more efficient and swift deployment of capital. Additionally, an ISO could facilitate a better integration of renewable capacities, utilizing collective generation potentials while minimizing congestion costs.

At the national level, governments should introduce amortization accounts to spread the high upfront costs of grid infrastructure investments over longer periods, making projects more financially viable. These accounts would allow regulated utilities and investors to recover costs gradually through network tariffs, reducing the immediate financial burden while incentivizing long-term investment in electricity grids. By aligning amortization schedules with the lifespan of infrastructure assets, governments can enhance capital efficiency and ensure that costs are fairly distributed across future energy consumers. This approach is particularly relevant as the benefits of integrating renewables and reducing congestion costs will primarily accrue to future generations, while investments must be made today. To further support these investments, governments could complement amortization accounts with targeted fiscal incentives, such as accelerated depreciation, investment tax credits or risk-sharing mechanisms. These measures would lower investment risks, attract private capital and secure a steady, sustainable flow of funding for electricity infrastructure upgrades. Additionally, they could help to mitigate substantial short-run tariff hikes, ensuring that the transition to a modernized grid does not place excessive financial strain on consumers.

To further expand financing options for grid infrastructure, governments and regulators should scale up the use of green bonds, establish transition funds and adjust capital requirements to attract private investment. Expanding green bond issuances, whether through national governments, the European Investment Bank (EIB), TSOs or a newly established ISO, can unlock additional capital by providing a transparent, lower-cost financing mechanism for grid expansion. National transition Funds, blending public and private capital, can further de-risk long-term projects and ensure steady funding, particularly for cross-border interconnections and renewable integration. Additionally, reducing risk weightings for infrastructure investments under the Capital Requirements Directive (CRD) and Solvency II would lower capital charges for long-term investors, making grid investments more attractive to institutional capital and improving liquidity in financial markets. These measures would mobilize private sector participation, keep financing costs manageable and reduce reliance on public funding while accelerating much-needed grid upgrades. By aligning these financial instruments with broader regulatory reforms, Europe can unlock the necessary investment to modernize its energy infrastructure while maintaining fiscal sustainability.

[24] Upgrading Europe's electricity grid is about more than just money

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