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# Grid, Baby, Grid

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Electricity grids are increasingly becoming the binding constraint of the energy transition: without higher and more timely investment—enabled by clearer planning, streamlined permitting and supportive regulatory frameworks—renewables and electrification cannot deliver their full benefits, as shown by the literature reviewed for the United States, Europe and Spain. However, existing regulatory models remain primarily designed to minimise stranded-asset risk, which can limit their ability to support rapid adaptation to a changing system. Addressing this tension may require rethinking how investment risk is shared and assessed at the system level over the transition.

## Global overview

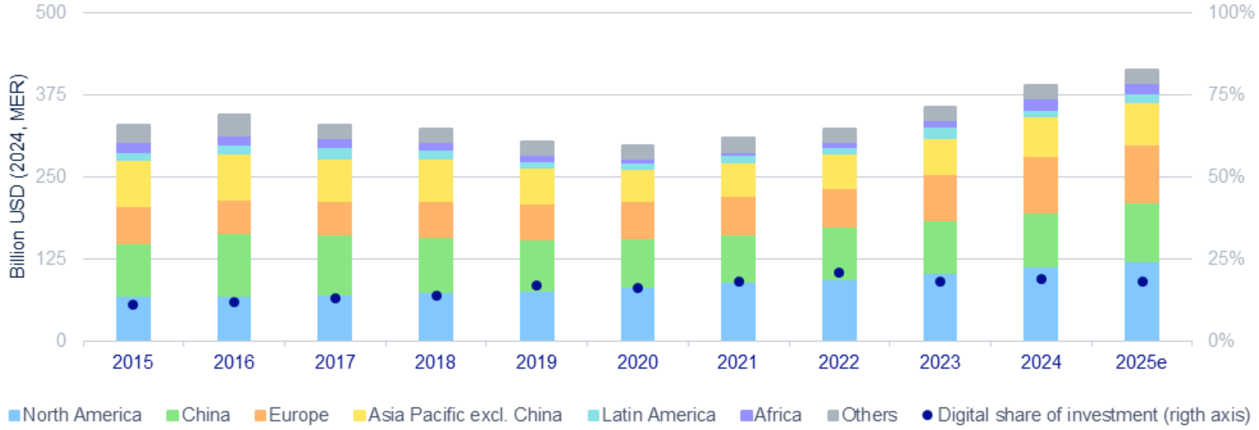
**Grid investment has lagged far behind renewable generation, leading to congestion, curtailment, rising system costs and delayed emissions reductions. As a result, the binding constraints to decarbonisation have increasingly shifted from technical feasibility to planning, permitting and investment frameworks.**[2]

**The decarbonisation of an economy hinges on two parallel processes: the electrification of final energy uses and the large-scale rollout of renewable electricity generation. Electricity grids therefore become a critical backbone for delivering a rapid and deep transition.** Transport, buildings and parts of industry increasingly rely on electricity, while wind and solar (characterised by spatial concentration and temporal variability) dominate new capacity additions. As a result, grids are an active system-level constraint shaping the speed, cost and feasibility of the energy transition. All in all, the net effect of rapid electrification and renewable energy adoption is likely to increase demand for electricity infrastructure investment, even as efficiency improvements in generation and integration technologies help contain costs and manage variability (Ito, 2026).

Investment in grids is falling behind. The International Energy Agency (IEA, 2023; 2024) shows that global renewable capacity is expanding rapidly and is expected to meet nearly all incremental electricity demand growth in the near term, yet investment in electricity grids has failed to keep pace. Grid investment has risen by only 20% over the past decade (**Figure 1**), starkly trailing the near doubling of spending on renewable generation . This mismatch has already materialised in growing connection queues, rising congestion and curtailment, and delays in electrification projects.[3]

[1]: I am grateful for the comments received from Pilar Más, Nathaniel Karp and Rafael Doménech, as well as for the reading by Diego Pérez and Lucien A. Vargas, and for the preparation of the congestion map of the electricity distribution network by Félix Lores and Jorge San Vicente.
[2] IEA 2026 further shows that, under rapid demand growth and increasing system complexity, insufficient grid capacity can also translate into heightened reliability risks, reinforcing the case for anticipatory network expansion.
[3]: North America has been investing around USD 10–20 billion more per year than Europe in recent years, and the gap has widened slightly

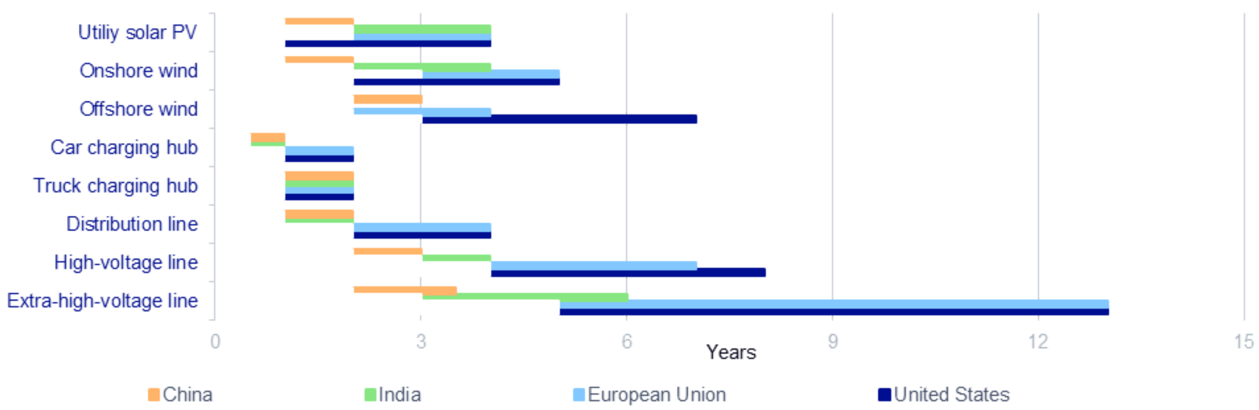
**Figure 1. INVESTMENT IN POWER GRID INFRASTRUCTURE AND SHARE THAT IS DIGITAL,** 2015-2025




Source: IEA (2025b). 2025e = estimated values for 2025. Digital investment includes smart meters, automation and management systems, end-point communication systems, transformers, EV charging infrastructure and analytics software. IEA analysis based on transmission and distribution companies' financial statements, S&P Capital IQ data (2025), Global Transmission data (2023).

**Grid constraints act as economic and regulatory bottlenecks to decarbonization.** From an economic efficiency perspective, constrained grids prevent low-cost renewable resources from fully displacing fossil generation, amplifying price volatility and slowing emissions reductions.[4] Under such conditions, electrification could even raise system costs if network expansion does not keep pace with demand growth. The literature therefore converges on the conclusion that planning, permitting and regulatory design,rather than engineering feasibility,have become the binding constraints on decarbonisation (**Figure 2**). Since network assets are long-lived and must be expanded under conditions of uncertainty about future demand, generation location and technology costs, this heightens the importance of anticipatory investment and robust regulatory frameworks.

**Figure 2. TYPICAL DEPLOYMENT TIME FOR ELECTRICITY GRIDS, SOLAR PV, WIND AND EV CHARGING STATIONS**




Source: IEA (2023). Ranges reflect typical projects commissioned in the last three years. Distribution line = 1-36 kV overhead line.

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since 2021.There is a stronger late-period acceleration in North America, consistent with higher load growth pressures, while Europe's increase is steadier despite significant congestion challenges.

[4]: The International Energy Agency (IEA, 2023) estimates that achieving stated climate targets would require adding or refurbishing more than 80 million kilometres of electricity networks worldwide by 2040—roughly doubling the size of today's global grid. At the same time, around 3,000 GW of renewable generation projects are already stalled in interconnection queues due to insufficient network capacity.

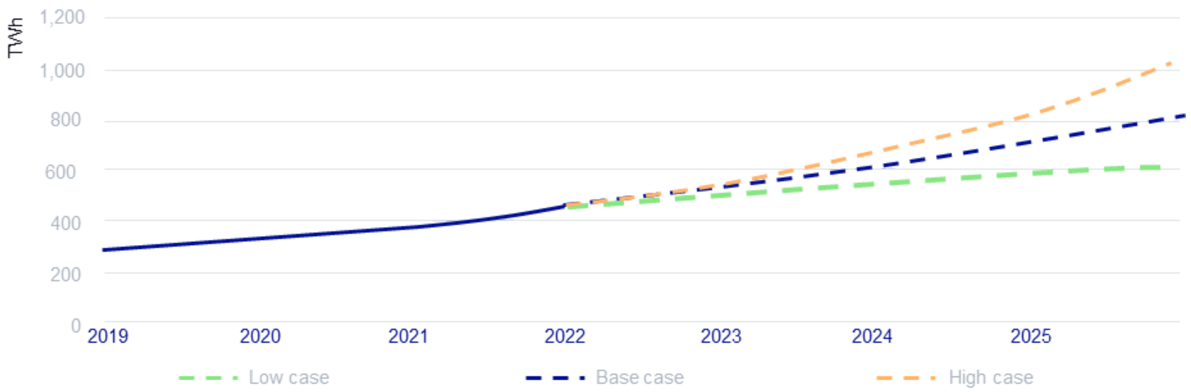
Transmission is split between (limits vary by country) high-voltage line = 36-220 kV overhead line; and extra-high-voltage line = 220-765 kV overhead line. To date, India has not developed offshore wind projects.

## The relevance of AI and digitalisation for electricity grids

**AI and digitalisation interact with electricity grids through a dual channel: they increase electricity demand, particularly from data centres, while also enabling more efficient grid operation. Grid-enhancing technologies or workload flexibility in data centers can raise effective network capacity and improve utilisation. However, digitalisation cannot substitute for physical grid expansion.**

**Artificial intelligence (AI) and digitalisation interact with electricity grids through a dual channel.**[5] On the one hand, data centres and AI-related workloads are emerging as a significant new source of electricity demand.[6] The IEA estimates that in several advanced economies, data centres could account for a substantial share of incremental electricity demand over the medium term, placing additional pressure on local transmission and distribution networks (IEA, 2025)[7] (**Figure 3**).

**Figure 3. GLOBAL ELECTRICITY DEMAND FROM DATA CENTRES, AI, AND CRYPTOCURRENCIES,** 2019-2026




Source: IEA (2024): Includes traditional data centres, dedicated AI data centres, and cryptocurrency consumption; excludes demand from data transmission networks. Low and high case scenarios reflect the uncertainties in the pace of deployment and efficiency gains amid future technological developments.

**On the other hand, digitalisation and artificial intelligence enable a range of grid-enhancing technologies (GETs) that can increase the effective capacity, reliability and utilisation of existing electricity networks (Figure 4).** These include dynamic line rating, advanced monitoring and sensing, power-flow control devices and topology optimisation, which allow system operators to safely operate networks closer to their physical limits and reduce congestion without immediate line expansion. In this context, demand-side

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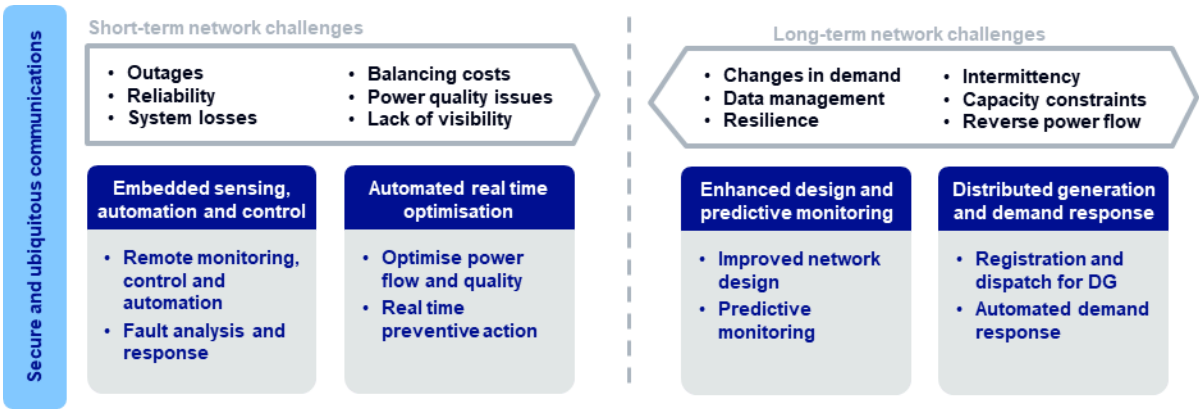
[5]: For a recent review on different promising uses of Artificial Intelligence see: "Unlocking AI's Potential to Serve Humanity" United Nations University-Centre for Policy Research. 2026.

[6]: Estimating how much electricity demand comes specifically from AI is difficult because AI workloads are increasingly intertwined with other data centre activities, definitions of AI vary, and operators often lack visibility into what runs on their infrastructure. As a proxy, analysts use accelerated servers, which in 2024 accounted for about 24% of server electricity demand and 15% of total data centre demand, but this is imperfect: not all AI runs on accelerated hardware, and not all accelerated workloads are AI. Future shifts of some AI tasks to end-user devices add further uncertainty to estimates of AI-related electricity consumption. IEA, 2025.

[7]: This demand is often spatially concentrated and time-sensitive, reinforcing the need for grid reinforcement and forward-looking planning.

digital solutions—such as **workload flexibility in data centres**—can further support system efficiency. By shifting computing tasks from peak to off-peak hours, data centres can flatten net demand profiles, improve utilisation of generation assets, reduce reliance on peaking capacity and lower overall system costs (Knittel at al., 2025).[8] In parallel, advanced analytics and machine learning can enhance load and generation forecasting, enable predictive maintenance, optimise congestion management and improve coordination of distributed energy resources (IEA, 2025).[9]

**Figure 4. DIGITAL SOLUTIONS TO TACKLE SHORT- AND LONG-TERM GRID CHALLENGES**




Source: IEA (2023). IEA analysis based on 3DEN, Unlocking Smart Grid Opportunities in Emerging Markets and Developing Economies (2023), World Economic Forum, Accelerating Smart grid Investments (2010).

**However, digitalisation does not substitute for physical grid expansion**. Flexibility and optimisation deliver their largest benefits only when combined with sufficient network capacity and a largely decarbonised generation mix. In already constrained systems, AI-enabled optimization can mitigate but not eliminate structural bottlenecks, and the need to invest in expanding the network in order to connect new demand.[10]

## Comparative analysis: United States vs. European Union

**Both the United States and the European Union face growing grid bottlenecks, but for different reasons. In the US, geographically concentrated renewable resources, fragmented planning, limited federal siting authority and unresolved cost-allocation disputes have slowed transmission expansion. In the EU, more dispersed resources and higher interconnection levels shift the challenge toward scaling grids for electrification and renewables, with policy centred on anticipatory investment and stronger EU-level coordination, contingent on effective national implementation.**

[8]: However, lower system costs do not necessarily translate into lower emissions. The emissions impact depends on the generation mix during off-peak hours: in renewables-rich systems, load shifting can reduce curtailment and displace fossil generation, lowering emissions; in fossil- or baseload-dominated systems, off-peak demand may instead be served by coal or gas, increasing total emissions despite cost savings. Reference: Knittel at al., 2025.
[9]: Case studies and modelling exercises reviewed in the literature show that digital technologies can defer some physical investments, reduce losses and improve reliability, particularly in distribution networks with high penetration of rooftop solar, electric vehicles and heat pumps.
[10]: Moreover, modelling of flexible data centres shows that while demand flexibility can reduce system costs, its emissions impact depends on the cleanliness of off-peak generation.

**Fragmented planning and permitting as binding constraints on U.S. transmission expansion**. In the United States, renewable resources (particularly high-quality wind and solar are geographically concentrated in the Midwest, Great Plains and Southwest. These regions are far from major demand centres, requiring large-scale transmission expansion to connect them. Decarbonisation scenarios therefore depend on long-distance transmission investment, which has lagged significantly behind requirements. Fragmented planning across utilities and regional operators, limited federal siting authority, unresolved cost-allocation disputes between states and lengthy permitting processes have emerged as the primary institutional constraints on transmission expansion. More fundamentally, the regulatory framework for transmission remains fragmented across jurisdictions and institutions, preventing the emergence of a coherent, system-wide framework aligned with the evolving geography of electricity supply and demand and limiting competition for efficient transmission and congestion-relief solutions. As a result, interconnection queues have grown rapidly and congestion costs have increased, undermining the cost advantages of cheap renewable generation. Without institutional reforms, the grid will remain a bottleneck despite cheap renewables (Davis et al., 2023).[11]

**Meanwhile, ambitious EU grid plans face coordination and execution bottlenecks**. In the European Union, renewable resources are more geographically dispersed and interconnection levels are generally higher, although uneven across regions. Ambitious electrification targets, rapid offshore wind deployment and the growth of distributed generation imply substantial needs for both transmission and distribution upgrades. The Commission estimates that several hundred billion euros of grid investment will be needed by 2030, rising to around €1.2 trillion by 2040.[12] To mobilize the required resources, the EU is promoting anticipatory grid investments and more coordinated planning at EU-level, beyond national silos. The European Grids Package places less emphasis on direct subsidies and more on regulatory and coordination incentives. These include a combination of anticipatory approval of grid investments based on EU-wide decarbonisation scenarios, future-proof network charges that prioritise long-term system efficiency, and regulatory incentives for digitalisation and grid-enhancing technologies (European Commission, 2025)[13]. The caveat is that implementation depends on member-state cooperation and timely legislative action.

[11]: Texas and the Midwest have thousands of megawatts of wind capacity that cannot be fully utilized because of transmission congestion, as evidenced by rising curtailment and negative wholesale prices. This has prompted policy discussions about building new transmission lines, expanding capacity within existing corridors—through upgrades, conversions, and other techniques to extract more capacity from current infrastructure—an area of active research and pilot deployment. (Davis et al., 2023).
[12]: It includes EUR 730 billion for distribution grids alone, and EUR 240 billion for hydrogen networks. Reference: European Commission. (2025).
[13]: These are complemented by strengthened EU-level planning and “gap-filling” powers where cross-border needs are identified but projects do not emerge, reinforced cost–benefit assessment and cost-sharing rules for interconnectors, and governance tools such as Projects of Common Interest, European Coordinators and the Energy Highways initiative to align national incentives with EU-wide infrastructure needs.

**Table 1. ELECTRICITY GRID COMPARISON BETWEEN THE EUROPEAN UNION AND THE UNITED STATES**

| Dimension | European Union | United States |
|---|---|---|
| **Renewable resource geography** | Geographically dispersed resources, strong offshore wind potential, and a growing need for cross-border interconnection. | Highly concentrated renewable resources, requiring long-distance interregional transmission. |
| **Demand drivers** | Electric vehicles, heat pumps, industrial heat electrification, and data centres: policy-driven electrification linked to both climate and competitiveness targets. | Electric vehicles, building electrification, data centres; market- and state-driven electrification. |
| **Grid remuneration** | Cost-of-service regulation with returns set by national regulators; EU-level coordination and Cross-Border Cost Allocation (CBCA) for interconnectors and other cross-border projects. | Cost-of-service regulation with fragmented federal–state jurisdiction and project-specific cost allocation. |
| **Role of federal / EU institutions** | EU-level planning and coordination via the Commission, ENTSO-E, TEN-E and PCIs, while implementation and final investment decisions remain primarily national | Limited federal planning authority; FERC regulates interstate tariffs but siting and planning largely rest with states and regional operators. |
| **Main barriers** | Permitting delays, cross-border coordination challenges, and misalignment between EU-level planning and national investment decisions. | Limited federal siting authority, unresolved cost-allocation disputes, and regulatory fragmentation preventing a coherent, system-wide framework aligned with the new geography of electricity supply and demand |

Source: BBVA Research

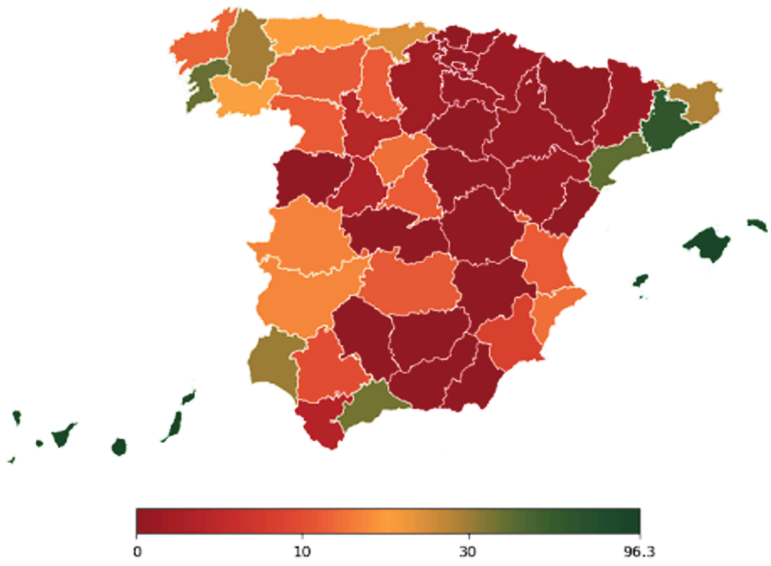
**Shared grid bottlenecks, divergent failures in the US and EU's grid development.** The US and EU both face grid bottlenecks, but for different reasons. In the US, renewables are concentrated far from demand centres; moreover fragmented planning, cost-allocation disputes and permitting delays (Figure 2)  have slowed transmission expansion, undermining the benefits of cheap renewables. While in the EU, more dispersed resources and higher interconnection shift the challenge toward scaling grids for electrification and renewables. And the policy response centred on anticipatory investment and EU-level regulatory and coordination incentives, contingent on effective member-state implementation.

## Box 1. The Spanish case: grid saturation, renewable curtailment and a binding investment constraint under rapid expansion

**Spain curtailed around 1.4% of its renewable energy in 2024, while 88% of electricity distribution grid nodes are reported as saturated. These outcomes are consistent with a pattern of underinvestment associated with historically reactive planning approaches and a regulatory framework originally designed for cost containment rather than rapid expansion.**

**Spain provides a particularly informative illustration of EU-wide grid challenges at national level**. Rapid renewable deployment, the expansion of distributed generation, and ambitious electrification targets[14] have sharply increased pressure on electricity networks, especially at the distribution level. Additionally, the network expansion has not fully kept pace with generation growth.[15] In this vein, the congestion of the electrical grid, combined with the lack of storage, caused Spain to waste around 1.4% of its renewable energy in 2024, according to ACER.[16] At the same time, **88% of electricity distribution grid nodes are reported as saturated**, significantly constraining the connection of new electricity demand and generation **(Figure 5)**.

**Figure 5. SPAIN: PROVINCIAL MAP OF ELECTRICITY DISTRIBUTION NETWORK NODE SATURATION**
(% OF NETWORK NODES WITH FIRM CAPACITY AVAILABLE FOR DEMAND > 1 MW)[17]




Red tones indicate saturated provinces, where less than 10% of distribution grid nodes have firm available capacity above 1 MW. Brown tones indicate moderately saturated provinces, with 10–40% of nodes exceeding this threshold. Green tones indicate non-saturated provinces, where more than 40% of nodes have firm available capacity above 1 MW. Firm capacity refers to non-interruptible connection capacity as reported by distribution system operators
Source: BBVA Research from distribution system operators data.

[14] Like electric vehicles, heat pumps, data centres, residential expansion, and industrial electrification
[15] For further details, see: Spain | The Power Grid, the Overlooked Cornerstone of the Energy Transition | BBVA Research. March, 15. 2025.
[16] Germany: 3%; France: 1.3%. Reference: Transmission capacities for cross-zonal trade of electricity and congestion management in the EU 2025 Monitoring Report. ACER. Sept., 2025.
[17] Firm available capacity refers to non-interruptible connection capacity that can be allocated under current network conditions without reliance on curtailment, exceptional operational measures or future reinforcements. The 1 MW threshold therefore captures whether distribution grid nodes can accommodate system-relevant new demand or generation with full reliability guarantees.

**Leiva Vilaplana (2023) shows that these outcomes are consistent with a pattern of persistent underinvestment, rather than temporary system stress.** Historically, Spanish distribution system operators (DSOs) have planned network investments in line with steady, organic demand growth, reinforcing assets as needs materialised. The current context, however, is more disruptive, with significantly higher expected demand growth, requiring a more anticipatory approach to network development.. This operating model reflects long-standing regulatory and informational constraints[18] and is increasingly misaligned with a system characterised by intermittent renewables, bidirectional power flows from self-consumption, clustered EV charging and rising industrial electricity demand. Limited real-time observability in medium- and low-voltage networks further exacerbates these challenges, potentially limiting the effective use of available grid capacity.

**Rodríguez, D. (2024) provides the regulatory explanation for this investment gap**. He shows that low regulated returns and binding investment caps have progressively weakened incentives for anticipatory grid investment, increasing the risk of persistent underinvestment. These caps (introduced during earlier periods of financial stress to protect consumers) were effective in containing costs, but are now misaligned with the scale and urgency of the required network expansion required. Rodríguez argues that, under the current framework, even economically efficient projects (such as reinforcements in renewables-heavy regions or upgrades to accommodate EV charging and new demand) can be delayed or excluded from remuneration, discouraging timely investment. To address this, Rodríguez argues that **investment caps should be revised or relaxed in a prudent and targeted manner**, allowing economically justified projects,such as reinforcements in renewables-heavy regions or upgrades to connect EV charging and new demand,to proceed in a timely way.

At the same time, **Rodríguez, D. (2024)** emphasizes that higher investment volumes must be accompanied by **strong efficiency safeguards**. Among his proposals is the **updating of unit cost benchmarks** used by the regulator, many of which are outdated after years of inflation and no longer reflect actual construction and equipment costs. He also recommends making the **allowed rate of return more responsive to financial conditions**. For example, by shortening the update period (e.g. from six years to three), so that remuneration better reflects changes in interest rates and financing costs without overcompensating operators.

Beyond remuneration parameters, Rodríguez highlights the need to strengthen the **institutional framework for planning and oversight**. He calls for a further strengthening of forward-looking grid planning led by the government, explicitly linked to electrification, industrial and climate objectives, and supported by **rigorous cost–benefit analysis** for major projects. To ensure credibility and efficiency, he also proposes **bolstering the regulator's supervisory capacity**—including additional staff and technical resources to audit grid investments—and **streamlining approval procedures**, which currently delay investment execution even when projects are economically justified.

[18] In particular, an investment cap set at 0.13% of GDP for distribution activities.

The Monitor Deloitte–aelec analysis reinforces both the diagnosis and the urgency of these proposals. Spain currently invests **around 0.2% of GDP in electricity networks**,[19] well below peer countries such as Germany or the Netherlands, and exhibits **one of the lowest allowed returns for distribution networks in Europe**. Deloitte further shows that regulatory uncertainty, administrative barriers and long permitting timelines—often **10–11 years for grid projects**—compound financial disincentives and translate into lost economic opportunities. In 2024, less than 10% of requested grid access capacity was granted to new demand under existing connection rules and network availability conditions, affecting industrial projects, data centres, energy storage and EV charging infrastructure.

While FEDEA, Deloitte and Rodríguez all stress the important role of digitalisation and smart grids in improving asset utilisation, flexibility and operational efficiency, they converge on a key conclusion: digitalisation cannot substitute for adequate physical grid investment under rapid demand growth. **Temporary instruments, such as EU Recovery funds, can alleviate bottlenecks but cannot replace a structurally sound remuneration and planning framework**.

**Spain's experience illustrates how electricity grids can become a binding constraint on decarbonisation.** Rapid renewable deployment and electrification have outpaced network expansion, leading to widespread distribution grid saturation and renewable curtailment. These outcomes are consistent with a pattern of underinvestment due to a regulatory framework oriented toward cost containment, including low allowed returns, binding investment caps and outdated cost benchmarks. As system conditions change—with faster electrification, higher investment needs and greater uncertainty—unlocking decarbonisation requires a shift toward more anticipatory grid investment, supported by a recalibration of remuneration parameters, streamlined approval procedures and stronger forward-looking planning, with digitalisation playing a complementary—but not substitutive—role.[20]

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[19] The investment cap is a legal constraint: in distribution it is set at 0.13% of annual GDP, which has constrained investment, while the cap for the transmission network is 0.065% of GDP, a level that has not been reached.

[20] It can also be added that there is a draft Royal Decree currently under process to raise the investment limits by around 60%, although the existing limits still apply. In addition, the National Commission on Markets and Competition (CNMC) has approved a new remuneration framework for electricity distribution for the 2026–2031 regulatory period, which continues to prioritise cost efficiency and investment control while shifting part of demand risk onto the distributor, as a portion of allowed revenues becomes linked to the actual evolution of demand and network usage rather than being fully insulated through cost-based remuneration.

## Box 2. Power storage as a complement to grid expansion

**Power storage can alleviate congestion, reduce curtailment and improve system flexibility by shifting electricity over time and providing ancillary services. However, storage complements rather than replaces electricity grids, as it depends on network access.**

**Power storage can help alleviate grid congestion, renewable curtailment and system flexibility challenges**. Storage technologies—particularly batteries and pumped hydro—play a valuable role in balancing short-term supply and demand, smoothing intraday variability of wind and solar generation, and reducing reliance on peaking fossil capacity. In power systems with high shares of variable renewables, storage can lower system costs by shifting electricity from periods of surplus to periods of scarcity and by providing ancillary services such as frequency regulation and reserves (IEA, 2023; IRENA, 2022).

**The literature consistently shows that storage complements rather than replaces electricity grids**. Storage assets are inherently grid-dependent: they require network access to charge and discharge, and their economic and emissions benefits depend on the ability to inject power into the system and reach demand centres. Where transmission and distribution networks are constrained, storage deployment is limited by the same bottlenecks that affect renewable generation and electrification projects, including saturated nodes, insufficient hosting capacity and lengthy permitting processes.

**Moreover, storage and grids address different dimensions of system flexibility**. Storage primarily shifts electricity over time, while grids enable spatial balancing—connecting geographically dispersed renewable resources with demand centres and integrating distributed generation, electric vehicles, heat pumps and electrified industry. Long-duration and seasonal storage technologies can reduce some network reinforcement needs at the margin, but they do not eliminate the requirement for robust transmission and distribution infrastructure under scenarios of rapid electrification and rising peak demand (IRENA, 2022; IEA, 2024).

## Conclusions

**Electricity grids have increasingly become the binding constraint of the energy transition: without faster planning, permitting and anticipatory investment, renewables and electrification cannot deliver their full benefits. While digitalisation, AI and storage can improve system efficiency, they complement rather than replace physical grid expansion. Current regulatory frameworks, largely designed to minimise stranded-asset risk, tend to favour delayed investment and are increasingly challenged by rapid system change; turning grids from a bottleneck into the backbone of decarbonisation requires rebalancing how investment risk is shared and assessed at the system level.**

Electricity grids have emerged as a central enabling constraint of the energy transition. Across global, European and US analyses, the literature consistently shows that delayed or insufficient grid investment can raise system costs, slows emissions reductions and prevents low-cost renewable generation from fully displacing fossil fuels. While digitalisation, artificial intelligence and flexibility solutions—including storage—can significantly enhance system efficiency and asset utilisation, they reinforce rather than substitute for timely physical expansion and modernisation of electricity networks.

Comparative evidence across jurisdictions indicates that institutional and regulatory factors—most notably planning, permitting and investment-enabling frameworks—largely explain differences in grid development outcomes between the European Union and the United States, even as both systems face growing grid stress. In the United States, regulatory fragmentation and limited federal coordination hinder the development of a system-wide framework aligned with the evolving geography of electricity supply and demand. In the European context, including Spain, long planning cycles and investment frameworks at national level have constrained network expansion, while rapid renewable deployment and electrification ambitions have increased congestion, curtailment and widespread saturation of distribution grid nodes.

Effective decarbonisation therefore requires treating grid investment as a core instrument of the transition: streamlining permitting procedures, strengthening planning and coordination, enabling anticipatory investment under uncertainty, and strategically deploying digital technologies to complement physical expansion. Without such reforms, electricity grids risk remaining a binding constraint on decarbonisation rather than fully becoming its backbone. However, anticipatory grid investment under deep demand and technology uncertainty remains an open challenge, as current regulatory frameworks remain primarily designed to minimise stranded-asset risk rather than to support proactive system expansion. Addressing this tension may require rethinking how investment risk is shared and assessed at the system level.

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