

Global Power Transmission



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About the Report

Our Power Transmission market report adds to our continued series of key energy transition focused industry reports. The collective works are the result of a valued research collaboration between ourselves and Alchemy Research and Analytics, a leading industry research group working actively across the energy transition markets. The report draws on macroeconomic data from multilateral institutions and industry-specific data from sources such as industry associations, government authorities / statistical departments, and the International Energy Agency (IEA). This was supplemented by news reports, trade journals, and related sources.

The report provides a current market overview of the global power transmission industry, including first-movers, key challenges, policy drivers, economics and outlook in major countries across Europe and the Americas. The structure of the report begins with an introduction to the principals behind the technology and industry. It then delves into detailed chapters on major topics, offering a holistic view of the possible industry directions, and highlighting growth opportunities, demand drivers, and investment considerations.

CleanBridge's INSIGHTS series of industry reports, aims to provide a comprehensive understanding of the key characteristics and trends prevalent in major markets for various technologies that will shape the energy transition over the coming decades. We hope you find our annual review of the Global Power Transmission market informative and enjoyable to read and we look forward to briefing you on other energy transition technologies in the upcoming months.



A handwritten signature in black ink, appearing to read 'L. Warren Pimm', enclosed within a hand-drawn oval shape.

L. Warren Pimm, CFA

Partner, & Sr. Managing Director
CleanBridge

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01

Executive Summary

Executive Summary

Worldwide, the energy transition and decarbonisation goals depend on the readiness of the power transmission networks. The advanced economies of Europe and the Americas, notable for the rising penetration of renewable energy, also have transmission infrastructures that have not kept pace with the changes in the energy mix. The backdrop is being shaped not just by the rise in renewable power generation capacities but also by the general rise in electrification and the resulting rise in the demand for electricity. IEA's projected 4% growth in electricity consumption for the year 2024 is its highest since 2007 (excluding the spikes after the financial crisis in 2010 and the post-pandemic period). For many countries in mature economies, the grid infrastructure is not fully ready.

The signs of strain are visible from the rise in the frequency of grid curtailment, negative prices in the bulk power market, and a pileup of connection requests. Even the long-term planning scenarios may not have fully factored in the capacity requirements. As of March 2024, a study on the European transmission utilities revealed that 11 out of 26 grid expansion/reinforcement plans were based on renewable

projections lower than the national targets. In the US market, the rise in interconnection requests backlog is predominantly led by the solar and hybrid (renewable-plus-storage) projects. It is unlikely to ease anytime soon.

A mix of measures for the near-term and longer-term horizons would solve this conundrum. The long-term and fundamental solutions lie in a host of steps comprising faster clearances, better incentives for investments and deployment of technologies. Active steps are underway on all these. Most important has been the regulators' willingness towards tariff revisions. The utilities' regulated returns are gradually being reconsidered. Similarly, regulatory interventions are easing permitting processes for projects, especially for the high-priority evacuation corridors. The short-term measures are largely around grid strengthening, reinforcement and grid-enhancing mechanisms such as the dynamic line rating technology.

The key pointers contributing to the evolving power transmission business are thus summarised here under the following four buckets.

- 1 The installed transmission infrastructure is due for renewal at a scale that is unprecedented by historical standards. There is a rising and acute need to reinforce and/or replace obsolete grid assets to maintain service reliability.
- 2 With energy transition outpacing network expansion, the decarbonisation roadmap is likely to be revised. Grid utilities are keen to retain coal- and gas-based power units longer than planned, while alternative low-carbon generation resources such as nuclear energy find renewed traction.
- 3 The grid capex plans point to an acceleration in spending. Utilities are seeking multiple channels to fund the planned investments. A rising number of utilities have tapped into green bonds or sustainability-linked bonds to raise funds in the capital market.
- 4 Despite promising investment plans, overcoming the development challenges will be critical to making a difference. Major power transmission projects continue to face delays, which adversely impact the commercials and the related generation projects.

- 1 The transmission utilities of advanced economies, i.e. the US and Europe, face the twin challenges of driving network expansion and renovating/replacing outdated assets. A majority part of their asset base is aged over 20 years. The US Department of Energy's estimates suggest that 70% of the country's transmission network is over 25 years old and fast approaching the end of the 50-80-year lifecycle. In Europe, similar estimates place the average age of the transmission grid at 30 years. The pressure on network reliability could rise with the emergence of major demand segments of electric mobility, electrification in industrial loads, and data centres.
- 2 The power markets with high penetration of renewable energy have had persistent grid management challenges. For the first eight months of 2024, the European region had negative grid prices for 7,841 hours. In some cases, prices reached €20 per MWh or even lower during the same period. Many of the power markets routinely curtail generation to balance the grid. Capacity expansion is the way to address this. However, the interim phase must be managed through available resources. This is why coal-based power plants are being kept longer than originally intended. Gas-based power plants are important as critical reserve assets – the US power market shows a rise in this generation resource.
- 3 Global power grid investment reached about \$326 billion in 2023 (BNEF, 2024). The investment outlook, based on the utilities' capital expenditure plans, points to an acceleration in total spending. BNEF estimates point to a 13% jump in grid investments between 2023 and 2024. By 2026, the total investments could be over \$400 billion. Notably, these investment estimates include high-voltage transmission and the lower sub-transmission or distribution networks. Besides debt, green bonds or sustainability-linked bonds have become increasingly important for capital raising by energy utilities, including those related to transmission and distribution grids.
- 4 The transmission network buildout is subject to significant uncertainty. Critical projects, especially the high-voltage interregional links, face delays due to permitting procedures. Added challenges lie in material supply chains (e.g., a global shortage of power transformers). The result is an unusually long lead time in commissioning new transmission links. Lately, policy and regulatory interventions have helped speed up some of the projects. All the same, such structural issues typically sustain for a long time. Investors and developers must factor in the inherent uncertainty involved in the transmission project pipelines.





02

Transmission Business Overview



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Globally, investors and developers are finding their clean energy project pipelines at risk due to a lag in transmission infrastructure. The projected electricity demand growth is boosted not only by the strong global macroeconomic recovery but also by new and emerging segments of electric vehicles, heating, and data centres. The upcoming renewable energy-led generation projects can meet the incremental demand without much reliance on conventional resources. But that is feasible only if the transmission linkages are assured.

A sharply changing energy mix has left the power transmission segment appearing as a bottleneck. Most transmission utilities are already grappling with crunched capacity, as evident occasionally in the grid curtailment measures or a pause in taking grid new connection requests. To be sure, they are responding to the emerging problem through network development plans and rate requests. The need may be for much more. At the same time, the incentive structure is in focus because the regulated return on equity must adjust to attract the capital needed for anticipated grid spend.

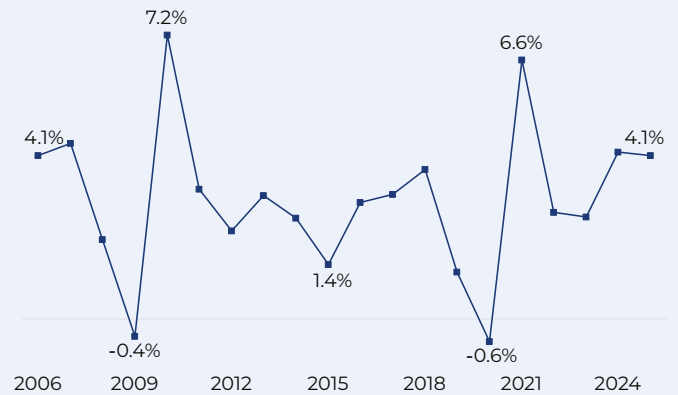


Power Market and Emerging Issues of Note

Globally, electricity consumption is set for an accelerated growth phase, partly recovering from the moderated rise in previous years. IEA's projected 4% growth (IEA, 2024) in electricity consumption by the end of 2024 is the highest since 2007 (barring spikes after the financial crisis in 2010 or the post-pandemic period). Notably, the demand growth is expected to be higher than global GDP growth in 2024 and 2025, unlike the preceding years of 2022 and 2023, when it lagged GDP growth. The ongoing turnaround in global economic growth, especially in the US and Europe, is of significant value in this context.

Strong economic growth, heatwaves, and sustained electrification are key drivers shaping the global electricity demand outlook. Long-term macroeconomic growth and fluctuation are typically factored into utilities' long-term planning exercises. A rough hand measure of looking at this relation could be the ratio between the total global electricity supply (because demand is an estimate while supply is an actual measure of realisation) and global GDP. There is a consistent relation between the two despite the variability. Emerging market economies' electricity demand could thus be expected to rise faster than the advanced or mature economies.

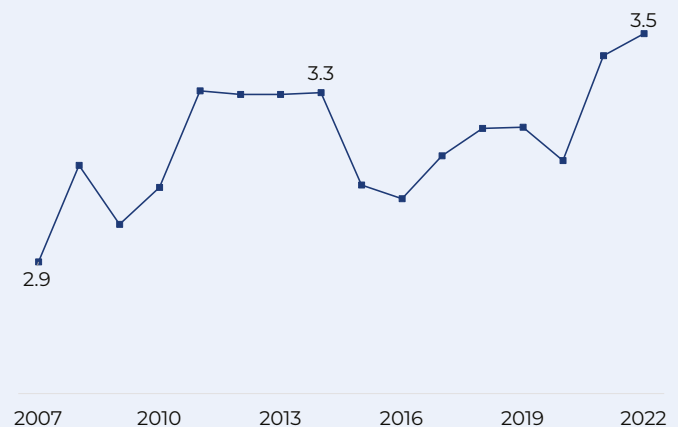
Annual Growth in Global Electricity Demand



Note: Data points were approximated to closely match with source data for the above visualisation

Source: IEA Report on Electricity (July 2024)

Historical Ratio Between GDP and Electricity Supply



Source: Energy Institute, Macrotrends



Across economies, however, electrification is fast emerging as an important demand driver. New industries or sectors, such as transport, constitute a demand for electricity that may not have been planned or provisioned for till recent years. In 2023, the global electric vehicle fleet consumed about 130TWh of power – insignificant (around 0.5%) so far in proportion to the global final consumption (IEA, 2024). However, it will change rapidly with a rise in vehicle penetration and charging base. With national targets set for mitigating emissions, electrification is also emerging as a major instrument for heating demand in the built environment. IEA's projections show that the share of electricity in heating for buildings and industry will double between 2021 and 2030 if all climate change-related pledges are to be met (IEA, 2022).

Policy goals are not the only determinants of demand. The mainstream adoption of applications based on Artificial Intelligence and Big Data technologies is generating an unprecedented demand for the electricity business through Data Centres. Globally, they share about 1-2% of the total power consumption, which is poised to reach 3-4%

by the end of the decade (Goldman Sachs, 2024). Strikingly, the US and European Data Centre markets' growth has altered the power demand and planning outlook for the utilities and regulatory authorities alike to the extent that some of the authorities placed restrictions on permits (e.g. Amsterdam municipality in the Netherlands). Many other markets are similarly anticipating a demand spike as developers seek new locations to set up the Data Centre capacities.

The global electricity demand outlook is largely a culmination of the growth factors at play in major economies/markets. In this regard, it should be noted that local factors influence a significant part of the countries' electricity demand picture. In the US, for instance, the estimated 3% growth in 2024 reflects a sharp spike over the country's previous few years' power demand trajectory. At the same time, China's 6.5% estimated growth in 2024 is the result of the country's moderated growth phase, involving a mix of high-growth and lagging sectors. The regional focus in this report will be largely on the Americas and European regions and will include references to others based on context.

Estimated Power Demand Growth in the Major Regions / Countries

	2024	2025	Pointers About Expected Growth
China	6.5%	6.2%	Ongoing economic restructuring could limit demand growth, while the industrial growth momentum could stay on track due to sectors like battery storage and material processing.
India	8.0%	6.8%	A strong economic growth outlook holds the key. In addition, the power system has been strained with peak unmet demand load due to heatwaves as evident in the first half of 2024.
United States	3.0%	1.9%	Anticipation of a sharp rise in demand due to the macroeconomic recovery, cooling demand arising from recurring heatwaves and the Data Centres.
European Union	1.7%	-	Demand growth will be in tandem with moderation in economic challenges. After the energy crisis of 2023, the energy-intensive industries resumed operations. Yet, the growth outlook is uncertain.

Source: IEA report on electricity (mid-year update July 2024)



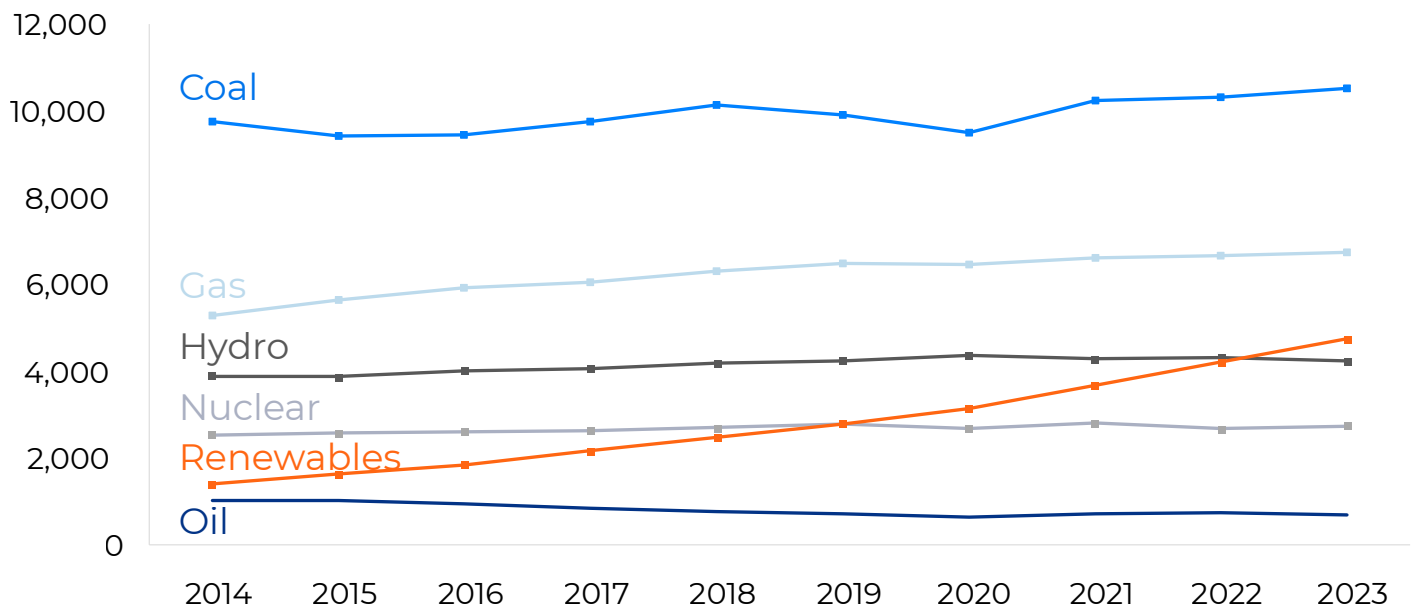
The sharp rise in global electricity demand is likely to be met with a record rise in clean energy-based power supply, especially from solar PV. Globally, by 2025, solar power is expected to cover more than half of the electricity demand growth. Furthermore, solar and wind together could make up over three-quarters of the demand rise during the same forecasted period (IEA, 2024). By then, renewables are likely to outpace coal-based power generation. Such projections just reinforce the energy mix shift underway across countries at varying speeds. The changing emissions profile of the power supply segment is almost a given worldwide.

Power sector emissions may plateau progressively through 2025 as renewable energy penetration displaces coal- and gas-based power capacities. There is at least a consensus about retiring the unabated coal (i.e. without carbon capture and storage technology) usage in the power sector. As of April 2024, the G7 countries agreed, in a joint communique, to shut down the unabated coal-based power plants

by 2035 (Guardian, 2024). The phase-out of coal, as a baseload option, involves issues that must be managed through alternate solutions, such as hydroelectricity, gas, and nuclear power, for network stability and reliability.

Utilities and power generation companies are using gas-based power as a bridging option in this transitory phase – switching/replacing coal units and/or balancing the intermittency of clean energy resources in the power mix. While gas as a fossil energy source too must be phased out, it has a role in bridging the ongoing energy transition route. Between 2017 and 2023, the share of gas in the total global electricity supply has been range-bound at 23%-24% (Energy Institute, 2024). The fuel pricing dynamics meanwhile influence the switching from coal to gas where feasible. The wholesale power market design in countries has a major contribution to these decisions (IEA, 2023). Competing fuel options such as nuclear power are also in consideration.

Global Electricity Generation by Source (TWh)



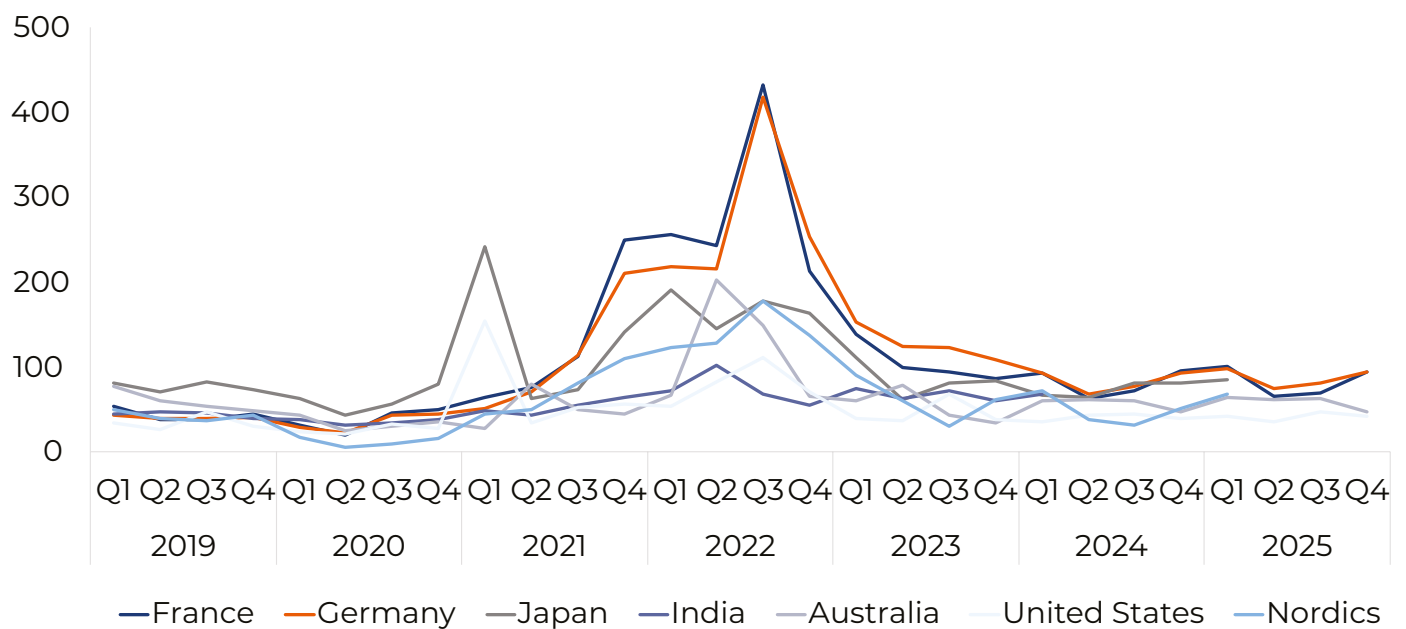
Source: IEA report on electricity (mid-year update July 2024)



Nuclear power is an alternate bridging energy resource for many countries. It is also on the rise, as evident in the progress of nuclear fleets across the major economies, including France (renovation works), Japan (decided to restart reactors), and China, India, Korea, and Europe, among those setting up new capacities. While globally, its contribution is unlikely to assume any significance, it will be an instrument for some of the economies to achieve ambitious decarbonisation goals.

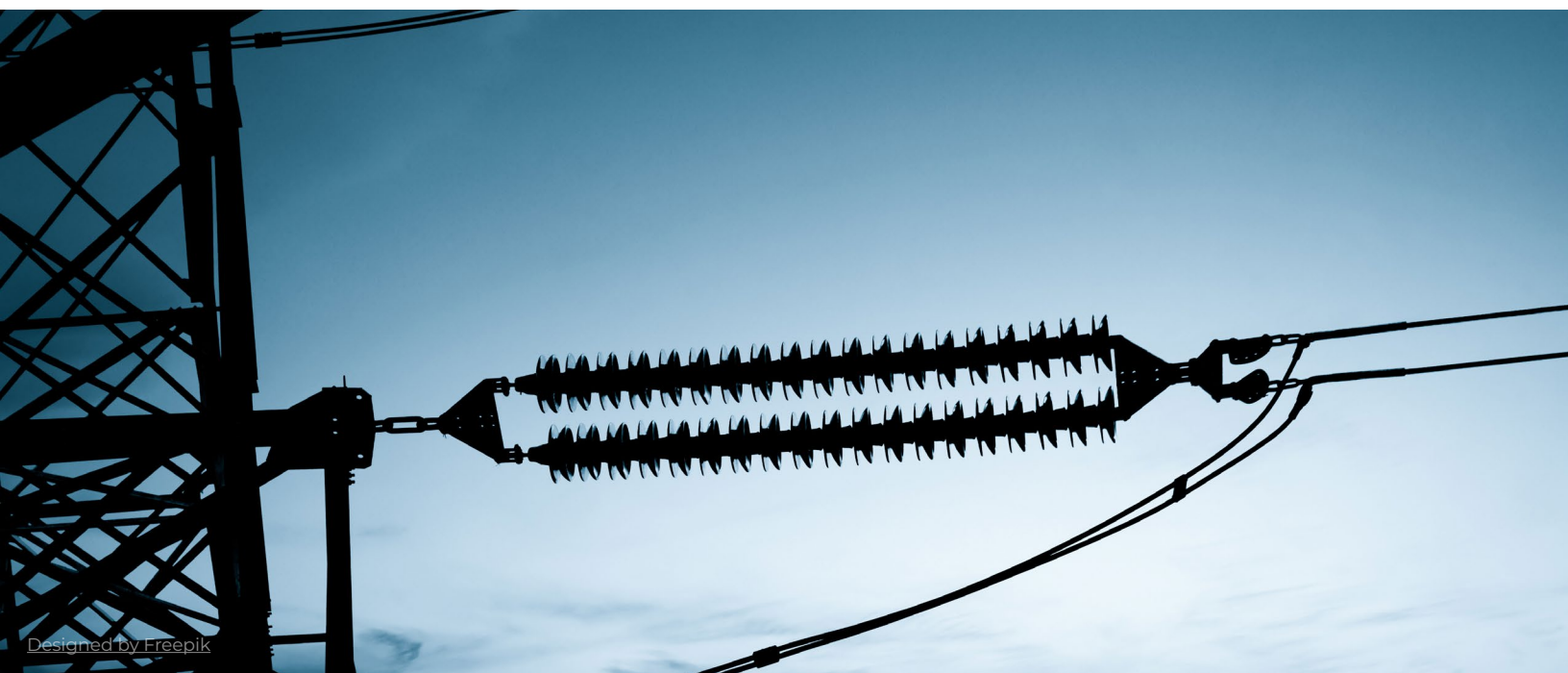
The market design has a vital role in ensuring the alignment of supply with demand. With wholesale power market transactions, utilities and network operators tie up the necessary capacities through contracts with generators for baseload, peak or contingency requirements. Reliance on certain fuel types is typically reflected in the power market prices. In 2023, for instance, the wholesale electricity prices declined in many countries, as compared to the high levels of 2022. Such a decline took place in parallel to the general fall in energy commodity prices, notably coal and gas.

Average Wholesale Prices for Selected Regions (USD / MWh)



Note: Data points for 2024 and 2025 refer to projections

Source: IEA



The role of renewable energy sources is seen at a much more granular or localised level. In 2023, for instance, the SPP power market region of the US registered the lowest wholesale electricity prices in locations where wind power generation was disproportionately higher than others (Berkeley Lab, 2024). A similar view was shared by the Australian regulator about the wholesale electricity prices in Southern Australia in 2023 – rapid growth in renewables slashed the prices and reduced dependence on coal-based generation units (ABC News, 2024). In such a scheme of things, the market design or structure is vital.

In May 2024, the European Council signed off on updated rules for wholesale power market reforms in the European Union (European Council, 2024). This is a culmination of the reform proposals taken up in the aftermath of the energy price volatility in 2022 (arising from a natural gas blockage amidst the Ukraine-Russia armed conflict). EU's market structure so far, with its marginal cost-based pricing (European Commission, 2024) made the gas-fired stations setting the market-clearing price. With limited clean energy capacities, prices spiked in 2022 due to a shortage of natural gas.

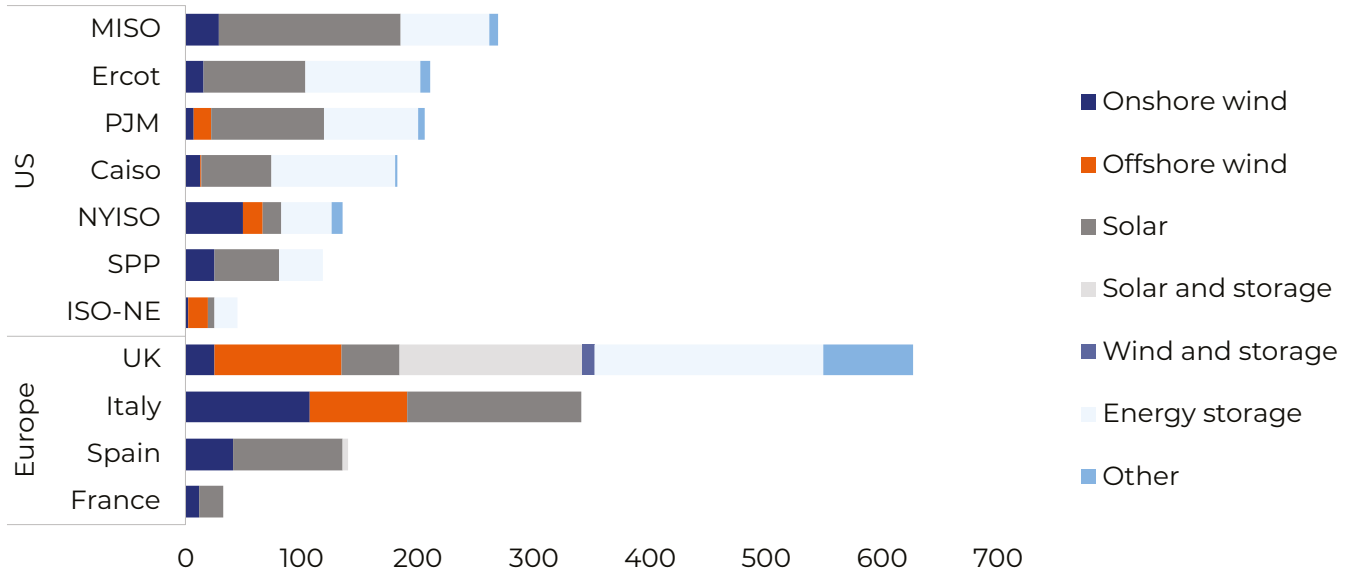
In 2023, Europe got relief from the declining natural gas prices and has, since then, reduced its reliance on natural gas. However, several countries in the region continue to rely on gas in their respective energy baskets. Furthermore, the interconnected nature of the European energy markets revealed several notable points during 2023. For instance, in France there was a shift in position from being a net importer to a net exporter as nuclear and hydroelectric output grew rapidly. Germany, however, became a net importer due to the phaseout of nuclear (ACER, 2024). Integrated energy markets enabled by cross-border interconnections have an important role in the region's energy prices.

Berkeley Lab's recent study of the US market illustrates the value of transmission linkages. In 2023, despite the fall in average wholesale electricity prices in the US, the market value of added transmission interconnection/links (equivalent to savings as compared to new local generation capacity) was higher than before. This means that, for given conditions of demand and supply in US electricity in 2023, expanded transmission would have provided the most value even when the wholesale prices had declined (Berkeley Lab, 2024).

From the investors' and developers' perspectives, the importance of transmission linkages can't be overstated. The rapid growth in the renewable power project pipeline, helped in significant part by a competitive bidding process, has meant longer queues of grid connectivity requests. The European market, leading globally in renewable penetration, faces a progressively intensified bottleneck in this regard. A March 2024 study on the European transmission sector by Ember, an energy think, revealed that 11 out of 26 grid expansion/reinforcement plans were based on renewable projections lower than the national targets (Ember, 2024). The problem is equally acute in other fast-growing markets. In 2023, the Brazilian grid operator (National Electric System Operator, or ONS) capped the amount of energy that renewable energy projects could inject into the grid. While ONS aimed at grid stability, the restrictions put wind and solar investments at risk.



Capacity Held in Grid Interconnection: Select Markets for Illustration (GW)



Note: ISO = Independent system operator. No data on "Energy storage" and "Other" for Italy, Spain and France. Data for US ISOs as of January 2024. Data for the UK as of July 2024. Data for Italy and Spain as of June 2024. Data for France as of end-2023.

Source: BNEF

Persistent challenges in the transmission network can have a cascading effect. For instance, prospective projects may not be able to secure financing if the transmission linkages are uncertain. The challenge of integrating wind and solar power amidst legacy grid management is progressively manifesting in multiple episodes of grid supply curtailment, power market price cannibalisation, and negative prices. To be sure, the resolutions of such challenges are not only about transmission capacity but also better grid management through technologies such as grid-scale energy storage. All the same, the grid capacity constraint is at the centre of the issue.

Leading Examples of Grid Curtailment to Manage Capacity Crunch

Poland	In March 2024, for the third time in the year, grid operator PSE announced a curtailment of 1,200MW-1,877MW worth of renewable energy capacity (PV Magazine, 2024).
California (CAISO)	Solar PV generation curtailment has been on the rise. In 2022 and 2023, it was 17% and 20%, respectively. In April 2024, it reached 23% (Factset, 2024).
Spain	In 2022 and 2023, non-compensated grid curtailments accounted for 1% of total renewable energy generation (Aurora, 2024).
Germany	In 2023, about 19TWh of generation (~4% of the total) was curtailed to manage the influx of additional renewable energy in the face of limited grid capacity (Clean Energy Wire, 2024).

Note: CAISO refers to California Independent System Operator

Source: PV Magazine, Factset, Aurora Energy Research, and Clean Energy Wire



Transmission System Operators

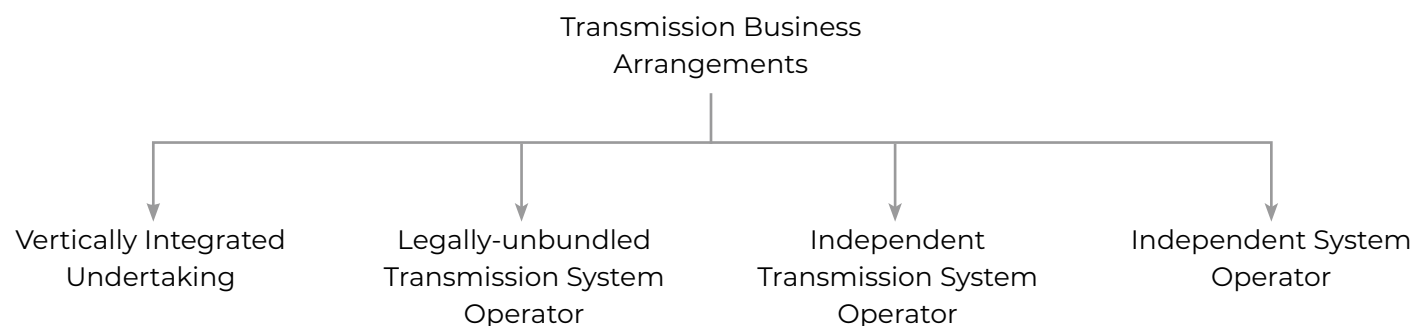
Over the years, in most countries, deregulation of the traditional vertical integrated undertakings ensured that power transmission is undertaken as a separate business entity (EPRG Cambridge, 2024). The restructuring process also led to the bifurcation of system/network operations and transmission asset operations for objectives of efficiency and neutrality in the business.

While the general direction of progress has been towards deregulation and restructuring, different countries have chosen the paths best suited for local needs. This means implementing variants of the deregulated structure for the country's power transmission business. For instance, in Spain and France, the state has full or partial ownership of the grids, even as the business is run by private entities. Ownership and operation, too, are unified into the same enterprise in some countries, notable examples being Spain's Red Eléctrica de España, Italy's Terna and the UK's National Grid. All of them own the grid assets besides carrying the grid operator's mandate. In September 2024, the UK government announced the acquisition of the grid operator to make it a publicly owned entity (Guardian, 2024) marking a shift against the privatisation done in 1990.

The business restructuring in power transmission over time also contributed to the rising role of the private sector. Most grid companies are either fully private-owned or not under direct government control, at least for the European and US grid entities. Presently, grid investments are predominantly driven by the private sector, which is better placed to tap into the capital markets than, say, municipal-owned entities (e.g. the French distribution system operators), which rely on bank-led financing. Even in countries with state-owned unbundled transmission utilities (e.g. India), there are competitively bid transmission projects to further the network expansion plans. Other countries, such as Brazil, follow the private concessionaire model for the transmission network – CTEEP is the private concessionaire responsible for about 30% of Brazil's total grid-connected power supply.

It is noteworthy that the markets with robust competitive wholesale power market structures generally coincide with an independent transmission system operator business. Yet, countries such as Australia, Brazil, Canada, and the US still manage to combine vertically integrated power entities with competitive wholesale power. Regulatory frameworks play a vital part in the entire chain, ensuring not only the rules of the power market but also the returns in the business.

Illustration of Various Business Arrangements in Power Transmission



Source: Electricity Policy Research Group, Cambridge University (Working Paper)



Regulatory Framework on Incentives for Transmission and Distribution Operators

Regulatory framework	Grid Operator					Customers		Both
	Cost recovery	Cost minimisation	Planning optimisation for total costs	Performance and operational efficiency	Innovation and best practice deployment	Affordability - cost minimisation	Quality of service improvement	Dynamically aligned cost and price
Cost of service / Cost-plus Rules are set to cover costs, with allowed earnings defined a priori (rate of return) starting from the determination of total cost of service	●	●	●	●	●	●	●	●
Price cap / Revenue cap Remuneration is based on a yearly cap that the grid operator can charge for each specific service (price cap) or on the amount that can be earned for each cluster of service (revenue cap)	●	●	●	●	●	●	●	●
Yardstick competition The operator's performance is compared with the other operators' performance of the sector, with penalties/awards consequently defined	●	●	●	●	●	●	●	●
Output/ Performance-based Remuneration is based on performance monitoring for each service (e.g. quality, losses) to incentivise continuous improvement	●	●	●	●	●	●	●	●

Impact on Indicator ● Poor ● Moderate ● Beneficial

Source: IEA (Report on Electricity Grids and Secure Transitions, October 2023)



Grid companies' profits are determined by the regulated returns on investments. Since such entities are natural monopolies in the business, the regulators set the maximum returns on equity. However, there is a trade-off in such a regulated incentive-setting mechanism. While consumer interests are important, the returns must attract capital for the enhanced investment requirements. Higher returns on equity correspond to higher grid charges. The spike in energy costs in 2022 made it difficult for many regulatory authorities to allow upward revision in tariffs.

All the same, rate hikes are being implemented to reflect the rise in capital and operational costs of managing the grid. This marks a departure from the near-stagnant rates over the last 5-10

years, especially in the US and European grids. The process of recovering the higher costs varies. In Europe and the US, the grid charges percolate down to the end consumers connected to the grid. There are other approaches being considered. The US utility American Electric Power proposed a new approach to the regulators, involving levying higher charges for the large new demand (thereby avoiding higher rates for residential consumers) to fund the cost of grid buildout. The UK regulations allow factoring in both capex and opex by adding both (called Totex) in the regulatory asset base for calculating returns. To be sure, capex still skews the overall calculations, but progressively, there is recognition accorded to the network modernisation initiatives such as renovation and digitalisation in the cost recovery.

Emerging Grid Fee / Cost Outlook across Countries (Illustrative)

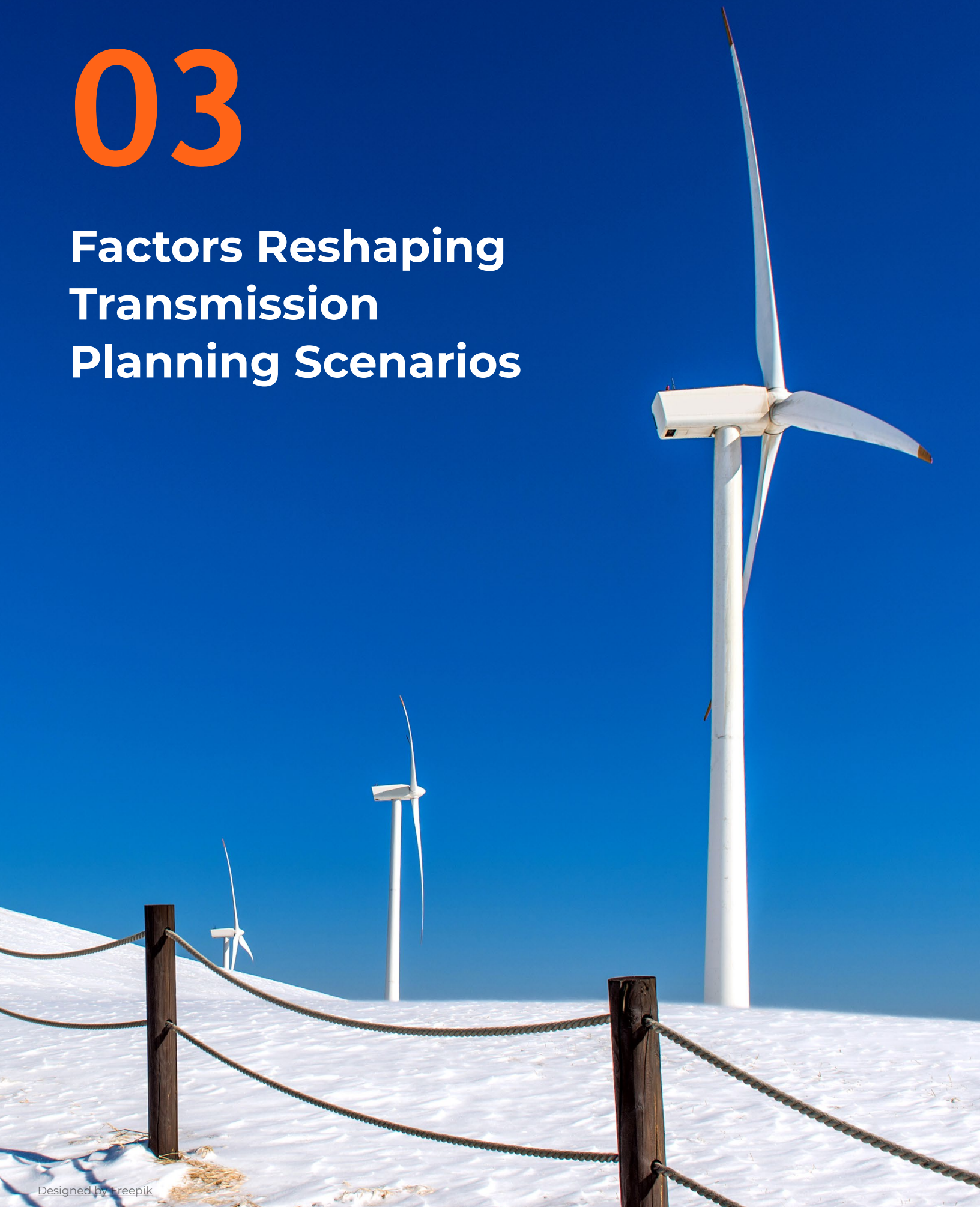
TSO / Country	Tariff Revision Outlook /Updates
TenneT / Netherlands	Grid fees nearly tripled in the last two years and are expected to rise further due to the offshore network expansion (AER, 2024).
National Grid / The UK	The cost of grid balancing amounted to £2.85 billion in 2023, which was borne by the consumers. In 2019 and 2020, these costs were £1.2 billion and £1.8 billion, respectively (NIA, 2024).
RTE / France	In July 2024, the French government intervened to pause the regulator-approved rise in consumer tariffs due to a planned 4.8% rise in grid fees (referred to as TURPE) (Connexion, 2024).
US	As of 2023, rate revision requests filed by electric utilities amounted to \$13.5 billion, reflecting the capex plans for network expansion. It was the third year of rising utility rate requests (S&P Global, 2024).

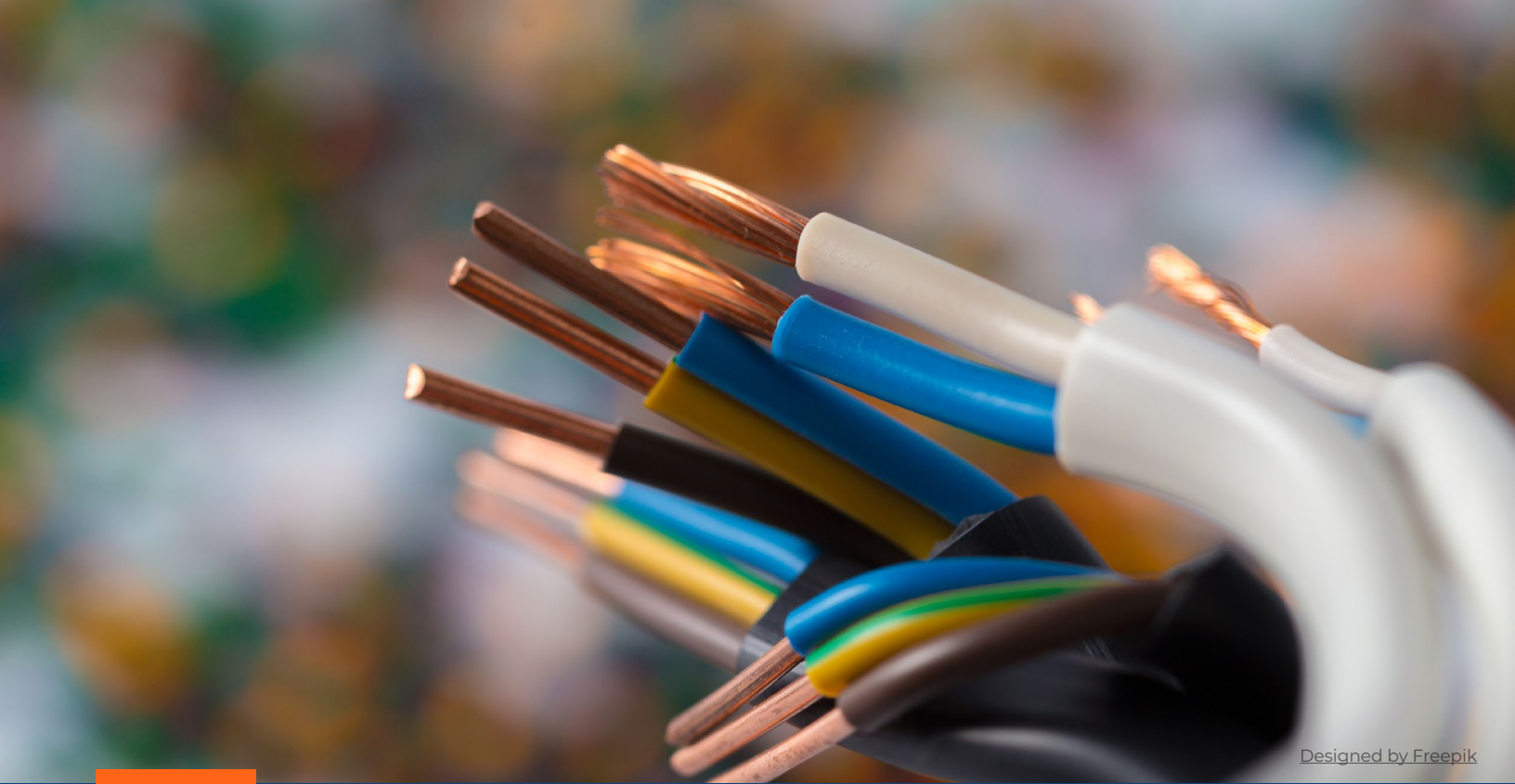
Source: Aurora Energy Research, Nuclear Industry Association, Connexion, and S&P Global



03

Factors Reshaping Transmission Planning Scenarios





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For transmission system operators, the long-term network development scenarios are subject to rising uncertainty. Policy objectives in decarbonisation and net zero must be taken into account. At the same time, the ground reality of grid preparedness may force TSOs to take a different direction. Gas-based power, for example, is replacing coal-based power in some markets due to a lack of reliable grid balancing options. The legacy grid management practices are also facing obsolescence with the rise in renewable energy penetration, most strikingly in the European region, where instances of negative grid prices have been frequent. As a result, flexible generation and energy storage are gradually becoming integral to the utility power mix.

This section reviews some of the key factors influencing transmission utilities' growth plans. It discusses renewable energy penetration and recent developments that indicate its implications, the role that conventional energy resources are playing in utilities' plans, and the emergence of grid-scale energy storage. The concluding part describes some of the major demand segments that have lately influenced the investment outlook.



Renewable Energy Penetration

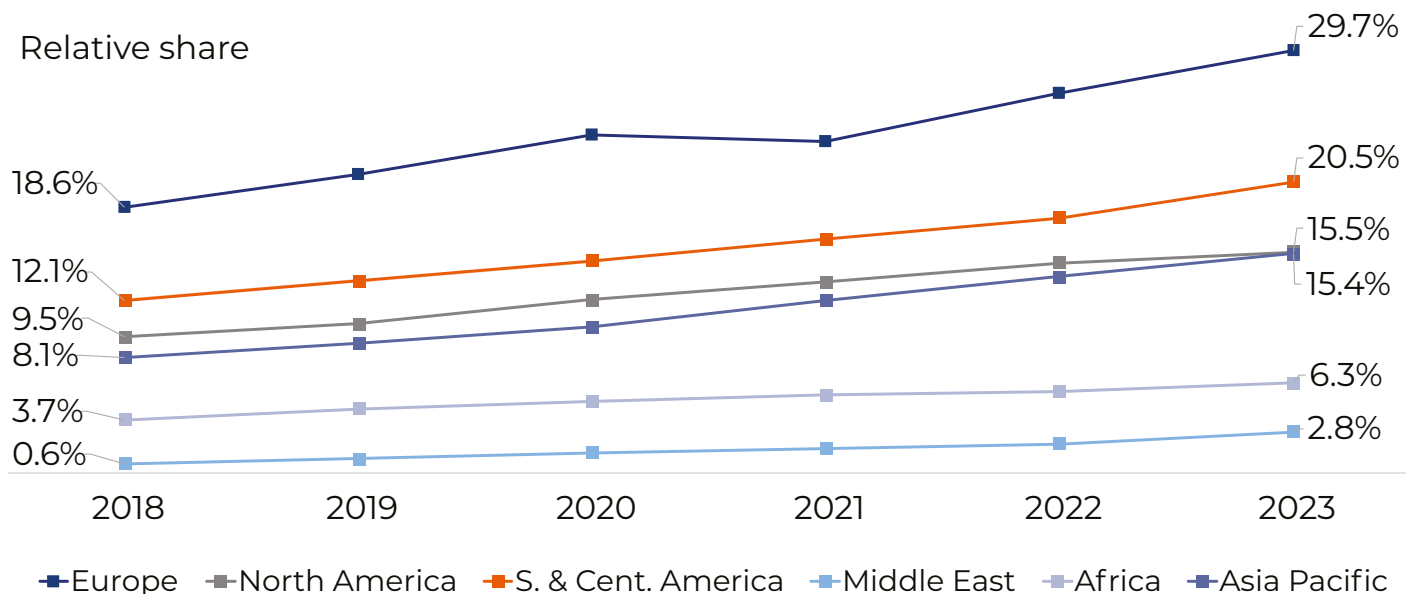
The role of renewable energy is projected to rise in importance through 2025 and 2026. With coal in retreat, renewables could overtake coal in the global grid-connected power supply by 2025 (IEA, 2024). In the advanced economies of the US and Europe, most of the incremental electricity demand could also be met through renewables. Over two-fifths of the renewable energy capacities in the next decade will be through wind and solar energy. Such an emerging energy mix entails a different way to plan transmission network development.

The countries experiencing high renewable energy penetration in their grids illustrate the dynamics well. Broadly, the task of integrating large-scale wind and solar deployment in the bulk power system comprises working on three areas. These include building/maintaining the response systems for short-term variability, putting in place sufficient generation to cover demand for all time blocks and ensuring frequency stability in the events of grid disturbance (NREL, 2024). With fewer balancing assets, as in thermal power generation,

integrating renewable energy resources is much more challenging and complex than before.

Renewable energy integration challenges extend beyond the technical requirements of stability and reliability. Power market transactions are sensitive to grid constraints. The European region displays some of these issues. For the first eight months of 2024, the European region had negative grid prices for 7,841 hours. In some cases, prices reached—€20 per MWh or even lower during the same period (WEF, 2024). This was the result of a surge in renewable power, especially solar, which the grid could not absorb during the time blocks. The frequency of such events is likely to rise as more renewable capacities connect to the grid and may be detrimental to renewable project pipeline and prospective investment if left unchecked. The solutions to mitigate such integration challenges include a combination of measures, such as energy storage, flexible generation options, and advanced grid management technologies, among others. Many of these steps are already under implementation worldwide.

Renewable Energy Share in Total Grid-Connected Power Generation



Note: Renewable Energy data above excludes hydroelectric power
 Source: Energy Institute Statistical Review of World Energy



Market mechanisms are part of the measures that help bring flexibility. Market-led flexibility might be urgent for countries characterised by high renewable energy penetration. One example is the Netherlands, where the transmission system operator awarded 'capacity limitation contracts' to a solar PV plant in November 2023. Such a contract is a form of congestion management wherein the solar PV plant is entitled to a pre-defined compensation instead of a possible backing down when needed for grid network stability (PV Magazine, 2023). While this signifies the short-term grid constraints, it also underscores the role of market design in aligning capacity.

Progressively, the transition of the existing centralised grid structure to a decentralised one is central to the future flexibility in power systems. Such a structure entails a fundamental shift, wherein generation units are dispersed and close to consumption. In such a scheme, transmission network assets address the significant systemic imbalances instead of being limited to power dispatch.

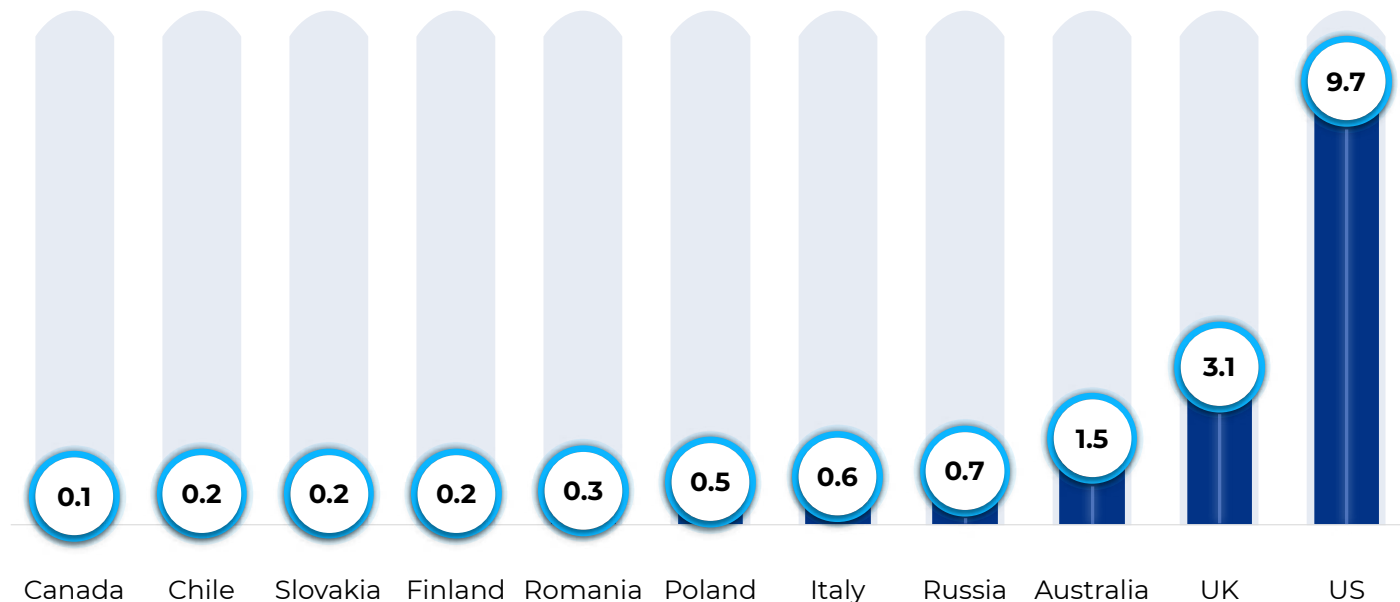


Conventional Energy in Grid Reliability and Decarbonisation Goals

Over time, energy transition has progressed on multiple fronts of the power mix. For instance, the phase-out of coal-based power generation is mainly in parallel with the exponential rise in the share of clean energy sources in grid-connected power. Other power resources, such as natural gas, hydropower, and nuclear power, are amid similar changes in contribution to the grid supply. It gives rise to a complex framework of inputs for the grid operators who must plan and secure regulatory approvals for the grid network assets well in advance. In particular, the grid operators' mandates on network reliability, stability and growth often face trade-offs against decarbonisation and net zero policy objectives.

The global push towards retiring unabated coal-fired power generation has notable pointers about the challenges. In May 2024, the G7 countries' commitment to a complete exit from coal by 2035 (Guardian, 2024) is encouraging but also ambitious. The UK closed its last coal-fired power plant on September 30, 2024 (Guardian, 2024). By the end of 2023, about 21GW worth of coal-based power generation capacity had been retired. (GEM, 2024). However, the momentum slowed down in the US and the European regions due to their respective operators' concerns about grid preparedness once the coal-based power is switched off.

Coal-based Power Generation Capacity Retired in 2023 (in GW)



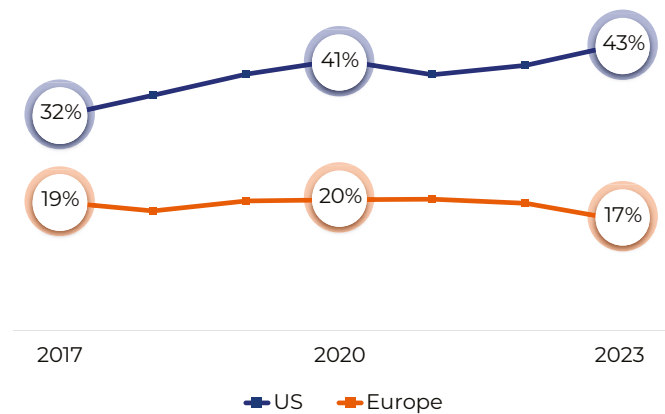
Source: Green Energy Monitor



In the US, the utility subsidiaries of CenterPoint Energy Inc., Alliant Energy Corp., and WEC Energy Group Inc. (all operating in the Midwest region) were among those entities that delayed coal retirements in 2023 to address short-term reliability concerns (S&P Global, 2023). The US Federal Electricity Regulatory Commission (FERC), in its testimony before a Senate hearing in May 2023, held that there is a potential crisis in some of the US power market regions, such as PJM, where capacity retirements could be faster than replacements. FERC's submission at that time pointed to the 40GW of retirements expected in PJM by 2030, against only 15GW-30GW of new units by then (Utility Dive, 2023). A select group of countries recently pushed back their coal retirement targets in Europe. These include France, Italy, Hungary, North Macedonia and Romania (BFF, 2024). It should also be noted that the 2022 European energy crisis (involving a natural gas crunch) prompted many in the region to revive old coal-based power plants.

The energy transition impact extends beyond coal. Natural gas has emerged as a vital resource for balancing grid requirements in peaking, short-term support, and the like. For many utilities, gas-based generation units are vital for grid-level contingencies. This is at least one primary explanation for the rise in coal-to-gas switching among European utilities. Favourable gas prices since 2022 have enabled such a transition. Notable countries in this regard include Germany, Poland and the Netherlands, where coal and gas capacity is available (Reuters, 2024). In February 2024, the German government announced plans to hold auctions for new gas-based power plants, which would be converted to hydrogen-based plants by the mid-2030s. The planned gas-based plants in Germany will support the transitory phase of shifting to near-zero emissions in power supply by 2035 (Clean Energy Wire, 2024).

Relative Share of Gas-based Power in Total Power Supply



Source: Energy Institute Statistical Review of World Energy

The developments supporting European gas-based power are limited to the short-term or medium-term horizon. The more significant trend of the share of gas-based generation in the European region is declining, which reconfirms the predominance of renewable energy. In the US market, though, gas-based power has risen consistently, reflecting its role in transitory support for the utilities and grid operators. Over the six years till 2023, the rise in renewable energy share (excluding hydropower) in the US grid supply, from 9.7% to 16.4%, was accompanied by an equally sharp increase in the share of gas-based power from 32% to 43%. Eventually, the share of gas-based power in the US power market would come down, as has been the case for coal. But that would be subject to the availability of reliable options for grid reliability.



The intersection of grid reliability requirements and a cleaner energy mix drive a revival of nuclear power capacity. Its lower emission profile combined with baseload capabilities helps provide it an edge over conventional energy resources. At the COP28 Climate Change Conference of December 2023, over 20 countries signed a joint declaration to triple nuclear power capacity by 2050. As a result, the nuclear power project pipeline is sharply rising globally. Between 2024 and 2026, capacity worth 29GW could be commissioned globally, led primarily by emerging market economies (IEA, 2024). In advanced economies, the capacity pipeline faces development and financing delays. All the same, nuclear power generation is forecasted to register an annual average of 3% growth

through 2026. The projected growth nets out the impact of ongoing phase-outs or retirements worldwide.

In summary, the energy transition towards cleaner energy resources impacts grid stability and reliability. The legacy dependence on conventional options in coal and gas-fuelled capacities must be replaced with equivalent capabilities. Presently, the grids are not fully prepared. This is why coal retirements slowed down, while gas-based power appears to be the best feasible interim option to balance intermittent wind and solar energy. Meanwhile, nuclear power is poised for a comeback as policymakers and utilities pull out all stops for an emission-free grid profile.

Revival of Nuclear Power Generation in the Energy Transition Matrix

Region	Country	Particulars
Asia Pacific	China	Global leader, with 27GW under construction.
	India	Announced in 2022, it plans to triple its existing capacity.
	Japan	Planned restart in 2024-2026 to help achieve emission targets.
Americas	US	Replacement for 37GW is due for expiry between 2030 and 2040.
	Canada	By 2036, a 1.2GW plant is due for commissioning.
	Brazil	A delayed project is scheduled for commissioning by 2027.
Europe	France	About 13GW of new capacity besides extension of existing fleet.
	Germany	The last of the nuclear power plants were closed in April 2023.
	Netherlands	Reversing earlier plans, it is negotiating for two reactors by 2035.
	Sweden	Two conventional reactors by 2035 and another ten by 2045.
	Belgium	Lifetime extension of two existing reactors worth 2GW.
	Poland	Permit granted for the first reactor. A second received approval.

Source: IEA



Grid-scale Energy Storage

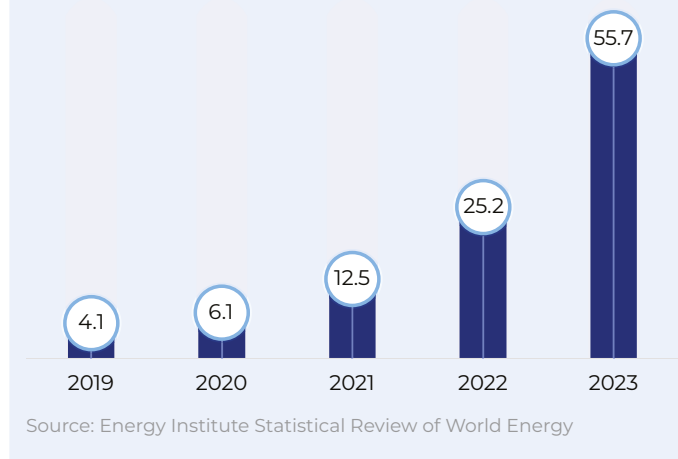
The globally concerted push towards energy transition is the primary driver in accelerating the storage capacity deployment. Grid-scale energy storage attracts the maximum interest as it contributes critically to the clean energy investment space. An estimated \$37 billion of clean energy investment in 2023 was towards batteries (IEA, 2023). Trend-wise, it was three times the quantum in 2021.

Utility-scale batteries are applied across a spectrum of grid management roles. This impacts the business prospects for the standalone battery developers, for whom the battery revenue stack signals the commercial viability and project returns. Notably, the energy storage applications are contingent on the wholesale power market regulations in the respective countries. The relative attractiveness of the markets is thus determined by the extent to which regulations enable storage-based power transactions.

Frequency regulation, for instance, is one of the leading areas of battery storage application, even as its relative share has declined over the years. Conversely, a few other applications, such as arbitrage, gained share sharply in the last five years, as battery units proved instrumental in capturing price advantages of peak and off-peak grid power transactions. Also noteworthy is the rise in the deployment of batteries specifically for the excess renewable energy generation injected into the grid. Its relative share has more than quadrupled in the US market.

Lately, investors are relooking at another important, though lagging, sub-segment of energy storage – pumped hydropower. It is the most widely used grid-scale energy storage technology globally. However, its growth plateaued due to the legacy challenges associated with gestation period, development barriers, uncertain costs, environmental and location constraints. Yet, the trend (IRENA, 2023) indicates a pick-up in capacity since 2021. This is

Grid-scale Battery Storage (in GW)



because of pumped hydropower's capabilities as a mature long-duration energy storage resource – an increasingly sought-after and scarce option for grid operators worldwide. One example of the rising interest is the UK's £1.5 billion Coir Glas Pumped Hydropower Storage project, marked as the country's first such project in the last 40 years.

Deployment of the energy storage assets may not be limited to grid management functions. It is also being considered an integral transmission asset beyond energy generation. A recent example is New York's grid operator (New York Independent System Operator, or ISO), which is evaluating the pros and cons of deploying storage assets to operate as the state's power transmission network (NYISO, 2023). It means the storage assets could contribute as a non-wire alternative to the transmission network to enable the dispatch and management of the generated energy.

Battery-based storage units have been deployed in Germany to enhance the hosting capacity of transmission lines and, in the process, mitigate the regulatory requirements in capacity redundancy (also referred to as the 'n-1' criterion). Such a model may, however, need many more such deployments to establish its commercial feasibility and clarify the apparent regulatory grey areas in market participation.



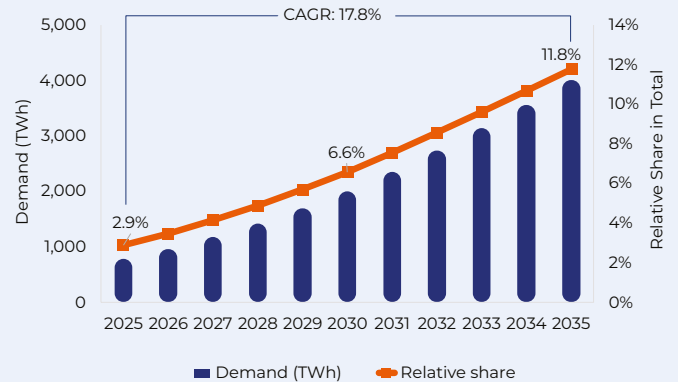
Emerging Demand Segments in Focus

Electricity demand projection is an integral part of the transmission planning exercise. In most cases, the utility's estimates for the demand segments stay range-bound. Lately, however, historical assumptions have become weaker and less valid. Technology developments and steady progress towards the electrification of sectors have forced a review of the electricity demand plans. It is also noteworthy that electrification is instrumental in decarbonising economic activities. The European Union's climate neutrality goals of 2050 hinge upon electrification to progress in tandem with renewable energy penetration (European Parliament, 2024).

In recent years, one of the most critical developments for power utilities has been the electrification of the hitherto non-electric or primary energy-driven sectors. One such sector is the heating demand load of residential and commercial buildings, shifting progressively away from coal, gas, or oil-based furnaces towards heat pumps running on electricity. A much more rapid shift in the transportation sector is in progress through electric vehicles for passenger and commercial uses. The fast-charging infrastructure to support electric vehicles constitutes a critical part of the electric vehicle ecosystem. For utilities, this is a demand segment to track for its proportional share in total load and the possible impact on local grid stability.

The projections, based on macroeconomic modelling, help reinforce the point. Electric vehicles, for instance, entail a comparatively faster rise in demand than buildings. This is understandable in the sense of nascency in transport electrification worldwide and the persistent inadequacy of the charging infrastructure, even in mature markets. Proportionately, the demand load of electric vehicles can be easily factored into the overall

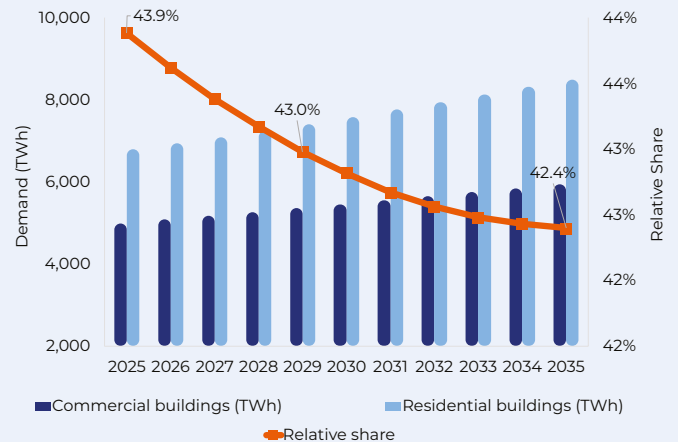
Projected Demand from Road Transport Electrification



Note: Projection is based on the macroeconomic modelling of historical data.

Source: BNEF

Projected Demand from Buildings



Note: Projection is based on the macroeconomic modelling of historical data.

Source: BNEF

network growth plans. However, its rapidly rising share and the impact on transmission and sub-transmission (or distribution) grids will be a point to track.

While the buildings segment clearly demands electrification, it projects a diminishing share of total electricity demand. Part of this is due to the weightage of mature/advanced economies, where the installations of heat pump appliances



in the built-up space have a small impact on overall demand and consumption. In some countries, heat pumps are already the largest source of heating – examples include Norway (60% of buildings), Sweden (40%) and Finland (40%), among others. North American region has the most significant number of homes connected to heat pumps. Furthermore, the building segment is also subject to various energy efficiency measures that have helped reduce energy intensity. It is still a segment to provision for, considering the projected compounded annual growth in absolute consumption – 1.8% in commercial and 2.3% in residential during the forecast period of 2025-2035.

Unlike buildings, the district heating segment continues to be relatively nascent in deploying electrification processes. Its decarbonisation has been largely untapped so far, with fossil fuels contributing over 90% of the total heat supply. Many entities are thus exploring a mix of options to meet the requirements, including low-emission electricity and other energy resources such as secondary heat (waste heat recovery), distributed energy systems, etc. Grid connection will be an integral part of the infrastructural support such systems will need in the coming years. The demand from this segment could be substantial once the systems are commercialised for implementation at scale.

Electrification, however, is one of many demand drivers for grid connectivity. The rise in cloud computing and the mainstream rollout of Artificial Intelligence-based applications have spiked the demand for Data Centres. These are energy-intensive facilities, made more so with complex, high-processing technologies and robust telecom coverage. Data centres accounted for about 1-1.3% of global electricity use, which is expected to rise with the increasing demand for digital services (IEA, 2023). Around 40% of a data centre's energy consumption powers its cooling and ventilation systems. Leading tech companies like Facebook, Google, and Microsoft are setting benchmarks by committing to power their data centres with

100% renewable energy. These companies also invest in Power Purchase Agreements to finance renewable energy projects, thus reducing their carbon footprints and operational costs (IEEFA, 2020).

For utilities in some of the leading data centre markets, i.e. in the US and Europe, the spike in demand from data centres has been unexpected and, in some cases, led to short-term challenges in accommodating grid connection requests. The US market is a notable case of illustration. The Data Centre segment appears to have shifted the country's power demand outlook, contrasting the near-zero level of demand growth over the previous decade. The implications, though short-term, are severe. Goldman Sachs' estimates point to \$50 billion worth of utilities' investments required in the US to support the Data Centre demand. Furthermore, the incremental Data Centre demand could drive about 3.3bcm worth of new natural gas demand in the US by 2030. The European context is not much different, as the region hosts around 15% of such global facilities. Countries like the Netherlands have had to pause grid connection requests to manage grid stability and avoid unmanageable grid congestion (Goldman Sachs, 2024).

To conclude, some of the significant demand segments for power networks lie in sectors such as electric vehicles, heating of built-up spaces, and Data Centres. The quantum and pace of each vary widely. Transport electrification is the fastest among sectors in terms of the demand growth outlook, for which both transmission and distribution networks must be prepared. The demand in the building segment is relatively flat, but a strong push towards electrification arises from power-to-heat technology systems like heat pumps. Lastly, the Data Centre segment is set to account for an unforeseen rise in power demand in the US and Europe. These demand segments are likely to influence the grid network development plans globally.



04

Transmission Network

Key Pointers on
Capacity and Growth



Designed by Freepik

The installed transmission infrastructure is due for renewal at a scale unprecedented by historical standards. While all TSOs are steadily augmenting their respective networks, the urgency of the energy transition makes it an unusual phase for all. The economically advanced economies are in focus due to their rising renewable energy penetration, an ageing transmission asset base, and drastically changing electricity demand profile. Emerging market economies, while largely relevant in the discussion, differ in terms of their energy growth trajectory and their position in the energy transition. Yet, with time the trends are converging between advanced and mature markets.

This chapter briefly reviews the major pointers that shape the narrative around transmission network expansion, grid projects like interregional interconnectors, the technology profile shaped by Direct Current-based transmission systems, and the role of modernisation in the investment plans drawn for long-term network development.



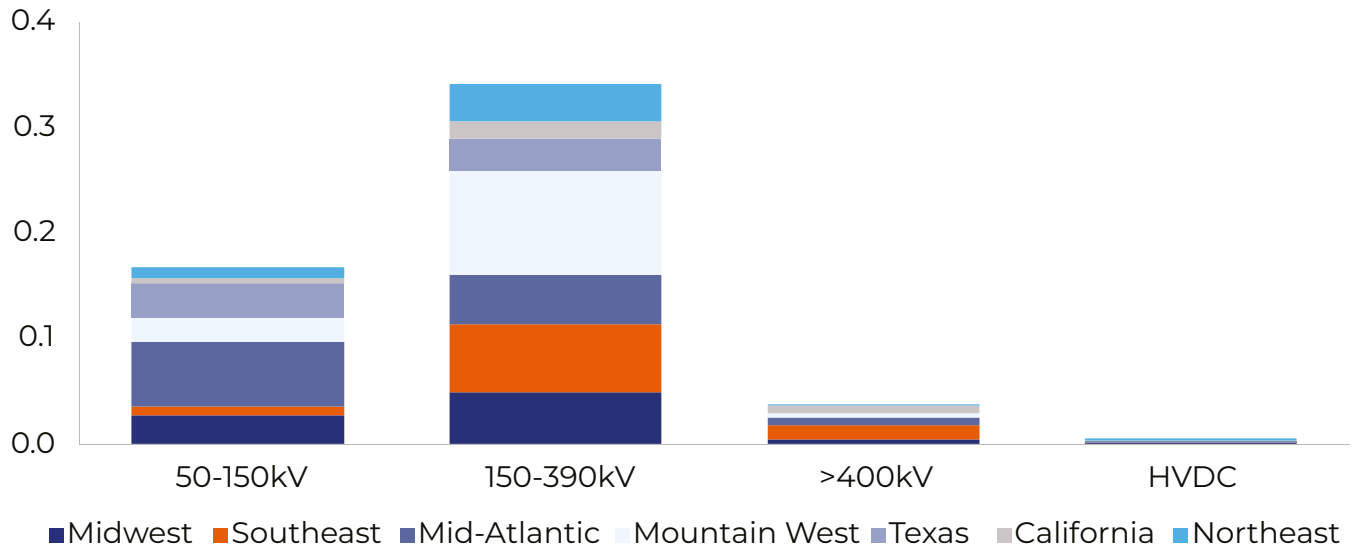
Pointers in Grid Capacity Growth

The electricity grid has expanded by approximately 1 million kilometres per year in the past decade. Most of this growth has occurred in the power distribution segment

responsible for last-mile connectivity. Globally, the bulk power transmission network makes up only about 7% of the total grid line length, totalling 5.3 million kilometres.

The US Transmission Network by Region and Voltage

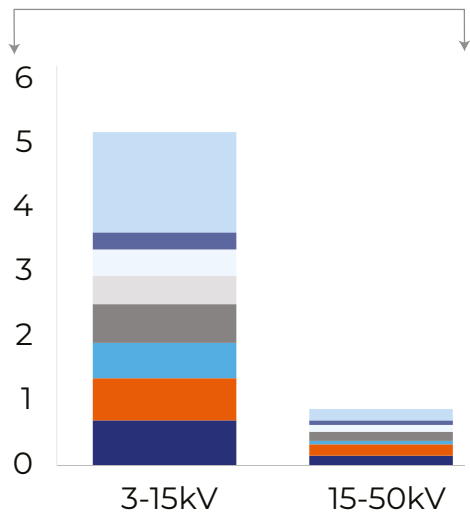
Million kilometers



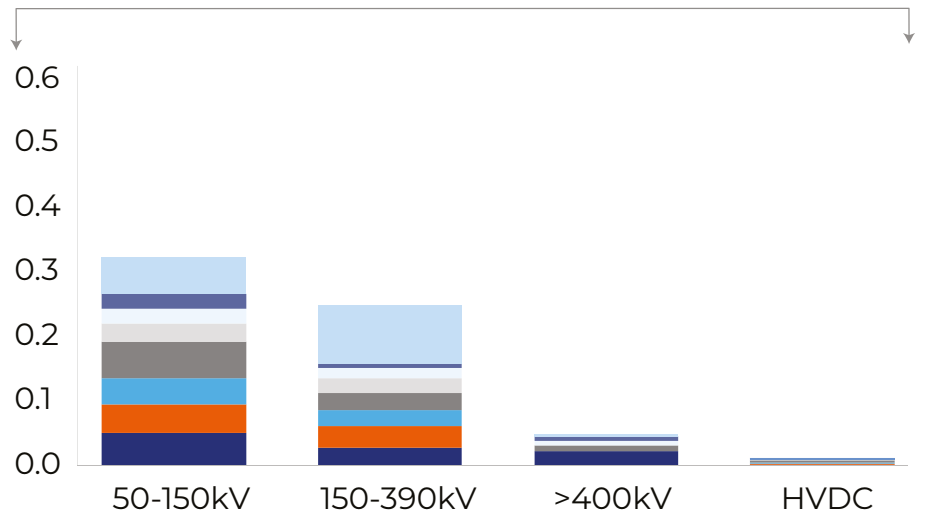
Source: BNEF

The European Grid Network by Voltage

Million kilometers
(Distribution)



Million kilometers
(Transmission)



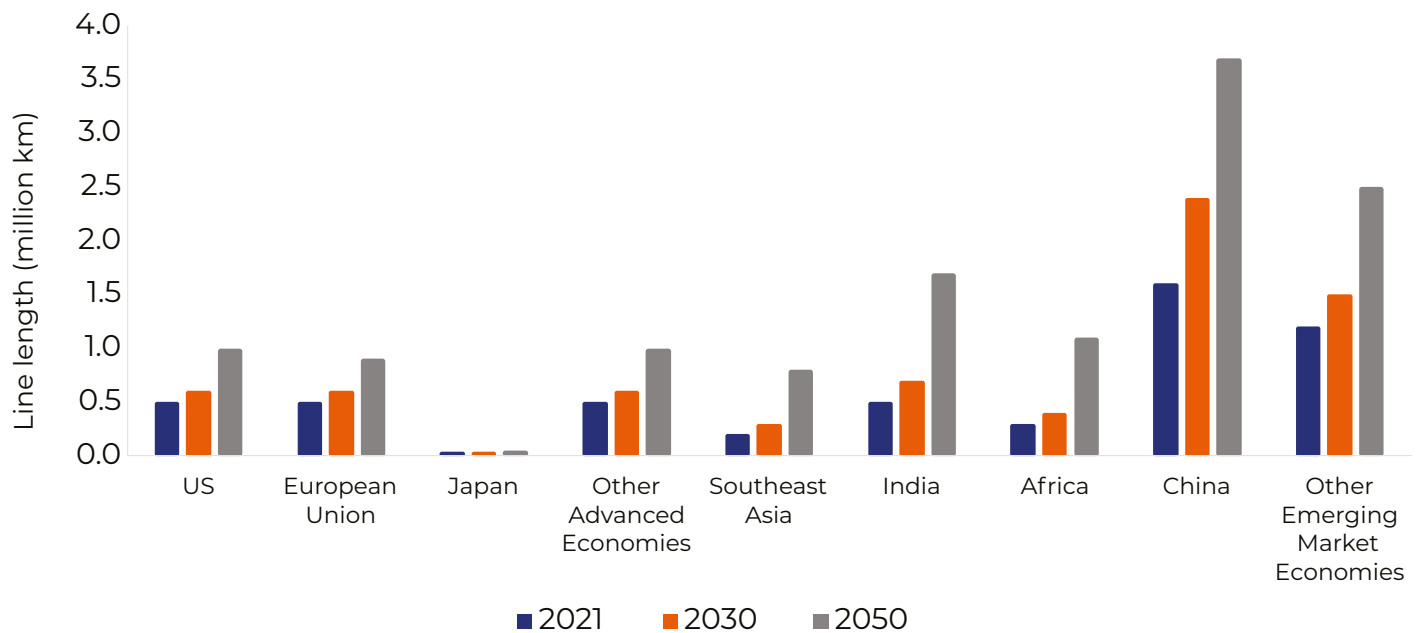
Source: BNEF



The growth of this network varies significantly between developed and emerging market economies, with countries like China, India, and Brazil leading the way in the latter category. Advanced economies have seen a 9% increase in their transmission line length, with notable growth in the European Union (12%) and the US (3%). While line length is a useful measure of network size and growth, it's important to note

that some utilities upgrade transmission lines to reinforce or improve existing lines without laying new ones. This can decrease total line length as multiple lower voltage lines are replaced with single or fewer lines of higher capacity. Such anomalies in growth trends are more likely in the ageing transmission networks of mature economies.

Transmission Line Length Based on Announced Pledges



Source: IEA

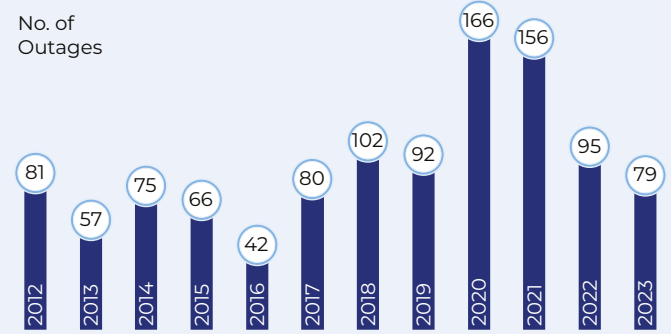


It is largely predictable that the power transmission networks of emerging market economies will grow faster than those of the developed markets of the US and Europe. At a granular level, the global growth trajectory in transmission has a few noticeable patterns across the regions and markets. For instance, the investment objectives vary across the regions. In emerging economies, the grid must expand to accommodate the spiralling demand growth from a historically low base. For perspective, the per capita power consumption in developing economies is at about 2,500kWh compared to over 10,000kWh in the developed ones (S&P Global, 2024). Excluding China, the developing economies spent about \$70 billion on grids during 2020-2022. In the same period, the developed economies had committed about \$170 billion, predominantly for network strengthening and reliability.

The urgency of grid reliability or reinforcement investments is driven not only by the age of assets but the changing risk profile. Climate change and the resulting extreme weather events present a major risk to grid network assets. In the US, for instance, between 2012 and 2023, one in three of the power outages were due to extreme weather (Swiss Re, 2024). There is similar evidence in Europe, where utilities managed blackouts arising from weather events. The region's integrated network may have aggravated the impact. In June 2024, the grid blackouts of Albania, Bosnia and Herzegovina, Croatia and Montenegro were caused by 400kV lines tripping, which were in turn triggered by abnormally high temperatures. Around the same period, grid malfunctions and outages were reported in Italy and Spain due to the unprecedented spike in load of high temperatures (Montel, 2024).

The frequency and intensity of weather events amplify the constraints imposed by an already ageing grid. This is most relevant for advanced economies, where weak assets compound the challenges involved in maintaining service

Instances of Power Outages in the US Due to Extreme Weather Events



Source: Swiss Re

reliability. To be sure, interruptions in high-voltage networks are minor relative to the lower voltage and distribution segments. Yet, it has an unacceptable economic cost. IEA's estimate of global economic loss due to grid-originated outages is \$100 billion (determined as of 2021) (IEA, 2023). In 2018, the US utility PG&E faced indictment for its ill-maintained transmission line causing wildfires. With liability damages worth \$30 billion, PG&E filed bankruptcy in 2019 and returned to business in 2020 (VJEL, 2024). PG&E's experience may serve as a salutary reminder of the critical need for transmission network reinforcement and renewal.

Reliability needs may also drive spending towards relatively lower voltage segments of the network. In 2023, the US utilities and developers spent \$25 billion on transmission infrastructure, marking a rise in outlay over the last decade. Yet, 90% of the spending in 2023 was for reliability-led low-voltage transmission projects that might be outside the transmission planning process (Utility Dive, 2024). EU's Modernisation Fund is among the major resourcing channels for supporting grid upgrades – about €3 billion were disbursed across 10 EU member states as of June 2024 for grid renewal, along with other grid connectivity projects (SEI, 2024).

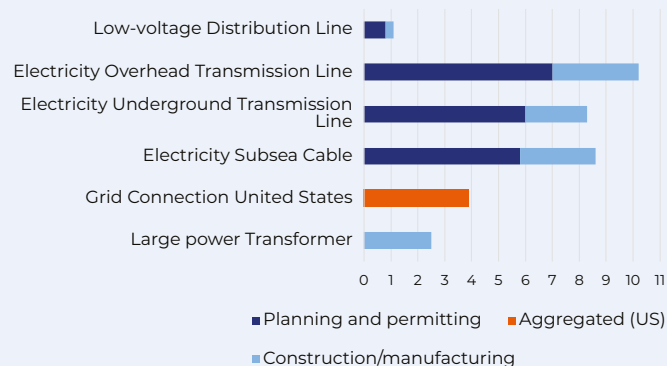


Many of the TSOs' ongoing network development activities have a few notable common points. One is the perpetual trade-off between the underground and overhead transmission lines. The former is understandably costlier than the latter but also offers resilience against inclement weather events. In each case, TSO decisions vary with local conditions. Danish TSO Energinet's long-term plan, for instance, involves dismantling and replacing the entire 3,200 circuit km long 132kV and 150kV network with new underground lines by 2030s (ReGlobal, 2020). Contrasting this, the German TSOs are opposed to the idea of underground cables altogether (switching to overhead lines could save €20 billion) and have expressed their reservations against the federal regulation that emphasises underground networks (Clean Energy Wire, 2024). In September 2024, a UK government notification ruled out underground cabling in the upcoming network expansion projects so that prohibitive costs do not deter grid connectivity (Guardian, 2024).

While utilities are gradually accelerating their grid reinforcement activities, the equipment supply chain has not kept pace. Delayed material supplies are among the bottlenecks to managing timely capacity addition or upgrades. In this regard, transformers have lately emerged as the critical asset equipment segment in focus. There has been a rising crunch in power transformers and generator-step-up (GSU) transformers in recent years. The OEM's average lead time for delivery of transformers rose from around 50 weeks in 2021 to 120 weeks in 2024. For large transformers and GSUs, the lead times could be 80-210 weeks (Woodmac, 2024). While manufacturers' investments have picked up, the time it takes to ease the ongoing constraints is not fully clear. The shortage of transformers could affect power generation projects as much as the grid assets.

A delayed or prolonged network expansion process is progressively becoming untenable. Equipment shortages are not the only issue. The lead time involved in getting the transmission grid assets online, whether new or refurbished,

Average Lead Time to Build New Power Grid Assets in Europe and the United States, 2010-2021



Source: IEA

needs a relook for possible compression. For instance, permitting and approvals, which constitute a critical intermediate (and regulatory) stage of the capacity addition process, are also the major contributors to delays and cost overruns. In an acknowledgement of this issue, the US Department of Energy, in April 2024, notified revised rules of issuing permitting decisions on new transmission lines within two years of applications, replacing the average four years earlier (Utility Dive, 2024). There are similar considerations in the EU region, where permits can take 4-10 years for grid reinforcements and 8-10 years in case of new high-voltage lines (EC, 2023).

Progressively, timeliness is a vital attribute in TSOs' network expansion frameworks. It was always a given that the transmission network capacity would expand by some magnitude to meet the foreseen demand and load. The energy transition investments, however, impose an urgency. To sum up, as above, some of the notable factors to track in the ongoing capacity addition phase include the measures towards building grid resiliency against extreme weather risk, reinforcement activities for service reliability, managing the flux in the material supply chain, and compressing the traditionally long lead time in project development.



Interregional Transmission Interconnections

Over the years, an important development in power transmission networks has been the rise of interconnector lines – typical high-voltage transmission lines that connect one region/ province or a power market with another to offer mutual benefits such as effective prices, generation utilisation and grid stability. Their role is vital in a world of rising renewable energy penetration and the challenge of integrating them with minimum volatility.

The EU signifies the same with several cross-border transmission interconnectors operational in grid stabilisation and demand management. By 2025, EU's grid operators are expected to make at least 70% of their transmission capacity available for cross-border trading. While challenging, the potential benefits can vastly outweigh the costs. It can, for instance, help minimise the grid congestion cost – about €4 billion was spent in managing EU grid congestion as of 2023 (ACER, 2024).

The European experience is also informative for the role of transmission interconnectors in avoiding grid blackouts. In 2022, the downtime in the French nuclear power plant fleet was significantly offset by the interconnections with its neighbouring power markets. There are other examples, such as that of Luxembourg, where imports through the interconnections with France and Germany help meet over 80% of the total power consumption (Rabobank, 2023). The NordLink (Norway-Germany) and North Sea Link (Norway-UK) have played a major role in stabilising the grid through Norway's surplus hydropower and the North Sea's excess wind energy. Relatively smaller countries such as Denmark have used the transmission interconnectors strategically in energy planning and avoided building redundant power generation capacities.

Major Interregional Transmission Projects Under Development or Planning Globally

Project	Particulars
EuroAsia Interconnector	A planned 1,500 km underwater sea cable interconnection of Greece, Cyprus and Israel. Greece's TSO is the project promoter. Despite delays, the project retains TSOs' focus (PV Magazine, 2023).
Greenlink Interconnector	HVDC interconnection line between Ireland and the UK with a nominal power transfer capacity of 500MW. The construction is underway, and commissioning could be in 2024/2025 (Greenlink, 2024).
North Sea Wind Power Hub	Planned HVDC interconnectors involving Denmark, Germany, Netherlands, Belgium and the UK to connect offshore wind power (from North Sea Island as a hub) worth about 10GW (North Sea Wind Power Hub Programme, 2024).
Australia-Asia Power Link	Planned 5,000 km long HVDC interconnection between Australia, Indonesia and Singapore for a potential 6GW of power transfer involving wind, solar and grid-scale battery storage (Sun Cable, 2024).

Source: PV Magazine, Greenlink, North Sea Wind Power Hub Programme, Sun Cable



Tapping into the promise of interregional transmission involves working around multiple challenges. At a fundamental level, these links are generally facilitated by inter-government agreements. The political buy-in is crucial before the technical and institutional factors (such as formulating uniform grid codes, a regional grid operator, etc.) are brought into the picture (IEA, 2023). This brings forth a multitude of coordination challenges, which can delay or even jeopardise them. Geopolitical factors, too, enter the fray. The EuroAsia interconnector project is one example of such a project being impacted by geopolitics (the Middle East conflict, in this case).

The challenges and delays in project development ultimately boil down to the bankability of projects. With high upfront costs and long gestation periods, timely financial closures are vital for developers. Multilateral investments, as has been seen in EIB funding, often help as bridging resources. However, the successful deployment of the interregional transmission projects would require much more than the potential benefits.

Illustration of Institutional Funding in HVDC Interconnector Projects Worldwide

HVDC link	Funding Agency	Particulars
Tunisia-Italy Interconnector (ELMED)	World Bank	In June 2023, the 600MW undersea cable HVDC project received the World Bank's approval for \$268 million in funding. Additional support came from KfW, the Green Climate Fund, EBRD, and the European Investment Bank.
Viking Link (UK-Denmark)	Nordic Investment Bank	A €134 million co-financing agreement was signed in March 2021 to fund the interconnector project.
	Export Credit Agencies (SACE and Euler Hermes)	This was the first time (as of June 2020) that a multiple ECA-backed \$743 million financing package was structured under National Grid's Green Financing framework.
Saudi Arabia - Egypt	JBIC	A \$103 million funding, as part of JBIC's Global action for Reconciling Economic growth and Environmental preservation. Others, including MUFG Bank Limited, Bank of Yokohama Limited, and Nishi-Nippon City Bank Limited, co-financed this project.
Nordlink (Germany-Norway)	European Investment Bank (EIB)	A €650 million funding package was approved in 2017, comprising €300 million to Norwegian TSO Statnett and €350 million to the German TSO TenneT.
Celtic Interconnector (Ireland-France)	European Commission (under 'Projects of Common Interest')	In 2019, the European Commission approved a €530 million part-funding for the Celtic Interconnector as part of the 'Projects of Common Interest'.

Source: World Bank, Offshore Energy, National Grid, EIB, Celtic Interconnector (EirGrid)



Technology (Voltage/HVDC, Digitalisation for Efficiency)

Long-distance power transmission, as is typical in renewable energy-based projects, involves higher voltage ratings for technical efficiency. Even in grid reinforcement and strengthening projects, TSOs uprate the existing lines to enable higher efficiency. Within the high voltage transmission segment, the High Voltage Direct Current (HVDC) technology has gained significant currency in recent years. Its rising deployments have had a favourable view amongst operators and developers. Practically, all the interregional transmission interconnector lines are based on HVDC systems.

HVDC has been found significantly beneficial in long-distance connectivity due to its lower technical losses and competitive costs as compared to the traditional Alternating Current-based transmission systems. Also, with progress in deep-sea cables technologies, submarine HVDC projects present a much more competitive option than before. The development of such systems might be crucial to tap into the emerging offshore wind power segment in many countries. Offshore wind

power projects are, in fact, a major demand driver for the HVDC systems. The German Federal Network Agency's long-term electricity development plan includes building 35 HVDC lines to connect 70GW worth of offshore wind energy by 2045 (Enerdata, 2024). Offshore wind is similarly an important resource in the UK (50GW by 2030s), for HVDC systems are being engaged – the Eastern Green Link is one of the largest HVDC projects planned in the UK and will be developed as a cross-border link between Northern Scotland and the UK (Eastern Greenlink, 2024).

Among other prominent technologies in recent years is the Dynamic Line Ratings (DLR) system, which is used for grid reliability and integrating renewables by adapting line capacity to real-time conditions. Due to their potential benefits, DLRs have lately joined the category of 'grid-enhancing technologies', with the federal regulatory authority endorsing its merits.



Beyond the grid-enhancing technologies, the TSOs' focus is also shifting increasingly towards digitalisation measures for potential efficiency gains. The share of digital technologies in total spending has risen from 12% in 2016 to about 20% in 2022. The increasing share of distributed generation-based renewable energy sources has made it difficult to track and predict the direction of energy flows within the grid, which is why digital technologies are assuming a vital role. Artificial Intelligence (AI) based systems are the latest innovations in this regard. Notable recent applications include AI-based demand forecasting to improve the accuracy of short-term energy predictions and address fluctuations caused by weather and other factors.

In summary, the technology profile of the TSOs broadly shows steady signs of shift in terms of the adoption of higher voltage ratings, HVDC-based deployments, grid-enhancing technologies such as DLRs and the greater involvement of digitalisation in operations. To be sure, all such measures are rooted in the local requirements and the corresponding cost-benefit analysis. Most of the emerging new technology measures are likely to be implemented in a staggered manner involving pilots and proof-of-concepts.

Select Examples of Dynamic Line Ratings Considered by TSOs

Utility	Particulars
Green River Energy (US)	The pilot project revealed capacity gains of over 40% compared to the seasonal static ratings
National Grid (US)	After a pilot, the DLRs were installed in May 2024, targeting an average capacity increase of 20%-30% on the four 110kV lines under consideration.
Noga (Israel)	DLR installation on a 161kV transmission line resulted in an 18% rise in transmission capacity, enabling operation closer to maximum line capacity.
Red Eléctrica (Spain)	In July 2024, the TSO announced the planned installation of 750 DLR devices on the overhead lines, aiming for an increase in capacity by up to 30%.
Litgrid (Lithuania)	The pilot project of DLR sensors revealed an average 52% increase in transmission throughput as compared to the established design.

Source: Canary Media, Latitude Media, Smart Energy International

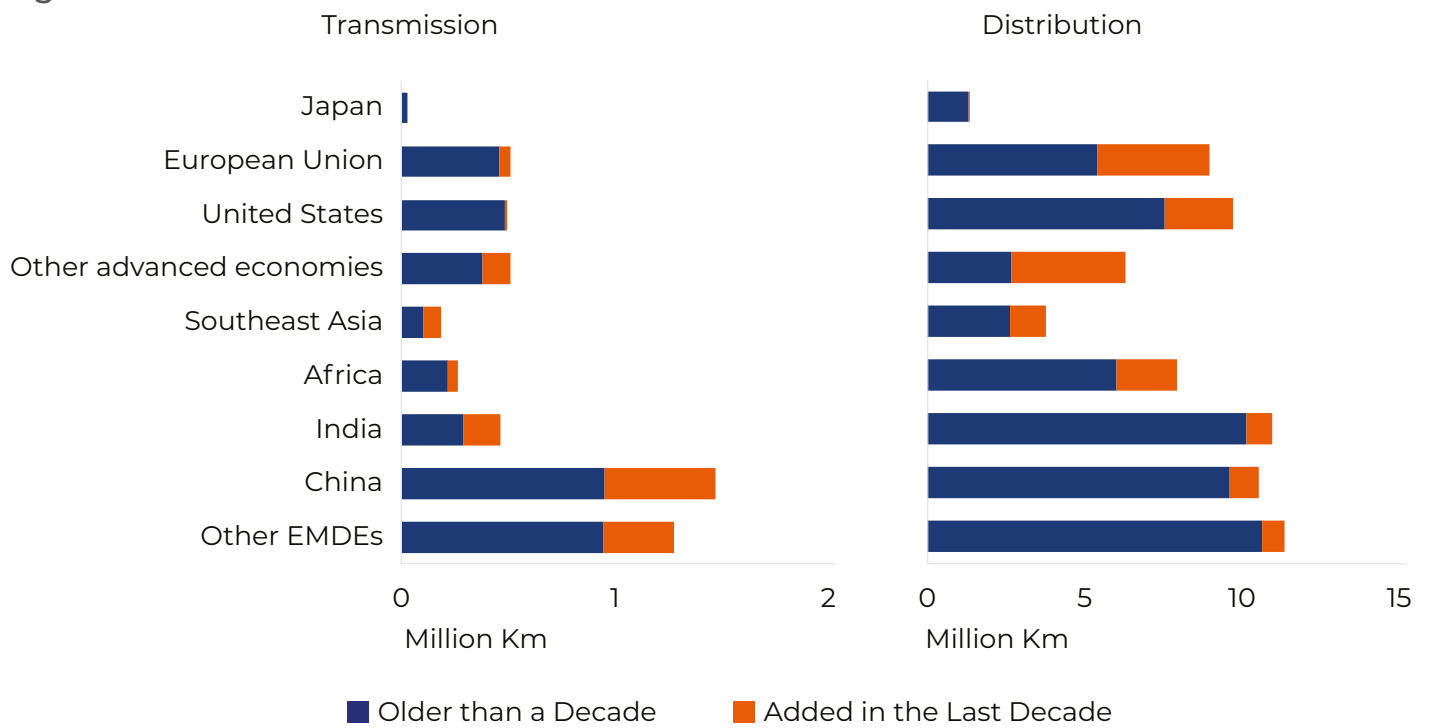


Ageing Infrastructure

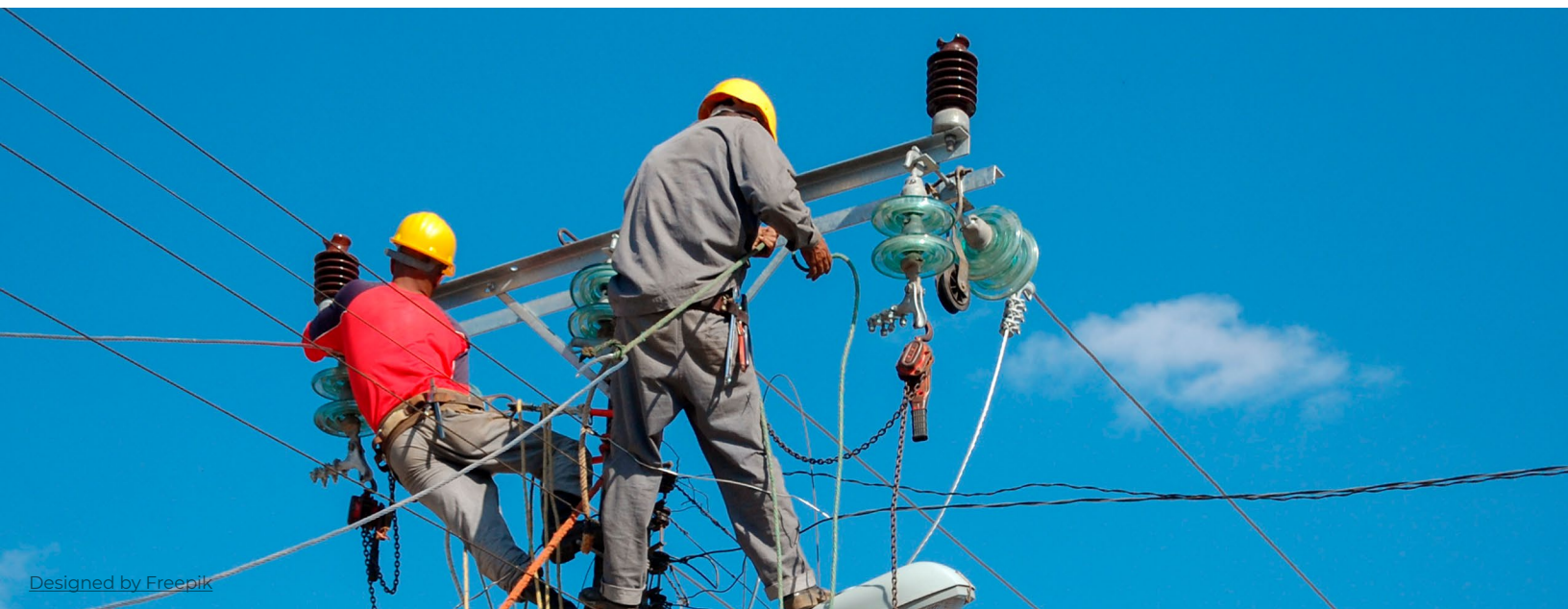
The introduction of advanced technology systems and innovations in power transmission tends to be oddly placed against an ageing asset base. While software-based innovations can get around the old assets, the hardware part needs replacement. While most of the countries have a predominant share of 10+ years in the transmission asset age, the acute challenge is in the advanced economies where a major part

of the asset base is aged over 20 years. The US Department of Energy's estimates suggest that 70% of the US transmission lines are over 25 years old and are approaching the end of their 50-80 years lifecycle (DoE, 2023). The European grid infrastructure is similarly grappling with an outdated structure, with average age of high-voltage transmission lines at 30 years (ERT, 2024).

Age Profile of the Transmission and Distribution Network Worldwide



Source: IEA



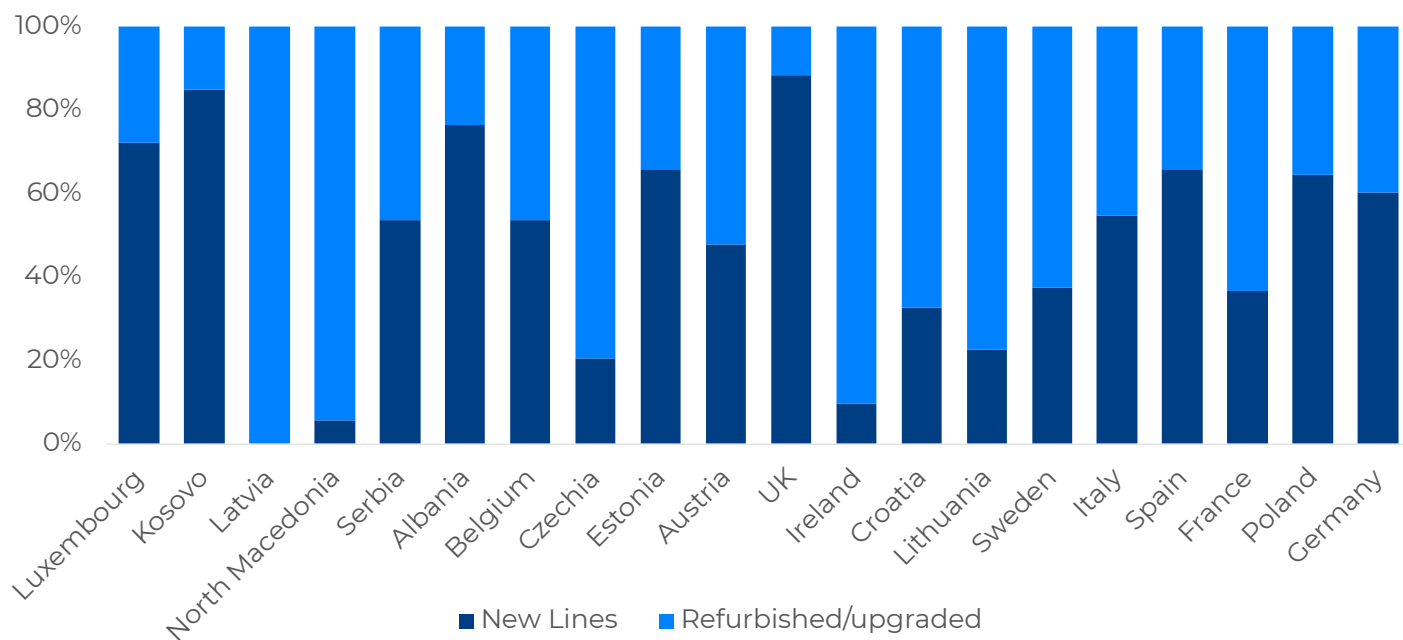
The backdrop of capacity addition is as much about grid modernisation as it is about expanding its access. Retrofitting with higher efficiency conductors, for instance, could help in minimising the network losses by 10% - 20%. Similarly, replacing outdated transformer units with improved models could rationalise energy consumption by up to 12% (Deloitte, 2024). The reinforcement measures also include boosting the physical infrastructure to make it withstand extreme weather possibilities. The key objective is to ensure that the transmission grid stays available all the time.

Utility-scale renewable energy projects would connect to the transmission system, hence the focus on grid preparedness. There are instances that highlight grid unavailability impacting generation projects. In 2023, the Polish grid did not have the capacity to accommodate renewable power several times over the year (ECFR, 2023). Modernisation and refurbishment can be regarded as important growth drivers of the spending and outlay devoted to the network development plans. In October 2023, the US

Department of Energy announced \$3.5 billion in funding across 58 grid reinforcement and strengthening projects. Utilities are chipping in with the rest. Modernisation is at the centre of the UK TSO's planned £58 billion investment by 2035 towards meeting decarbonisation goals (Current, 2024). EU's annual €23 billion spend on the grid network (including both transmission and distribution) is primarily led by refurbishment needs. The European Commission estimates point to an investment requirement of almost €600 billion for the transmission and distribution networks by 2030. Most of it goes to upgrades and modernisation.

The scope of grid refurbishment is almost equivalent to establishing a new super grid over the existing one. The lumpy nature of such investments means that even with the best efforts, progress will involve a protracted path. It may also mean that the industry may have to put up with bottlenecks in the short-term at current rates of growth in renewable energy projects.

Split Between New and Upgraded Lines in the European Region's Investments



Note: The above data is based on the TSOs' Ten Year Network Development Plans.
Source: Ember



05

Investment and Financing





Designed by Freepik

The grid operators' unprecedented capital expenditure requirements, as indicated in their long-term network development scenarios, must be supported through multiple funding routes. On the part of the regulators, there are rate revisions that must be considered to ensure borrowings make sense. Multilateral institutions' funding may start playing a bigger role than before, especially for critical projects of bankability, such as grid reinforcements and interregional transmission links. Meanwhile, the changing nature of the grid expansion projects adds to the dimensions for the regulators and financiers alike – for instance, digitalisation and grid-scale battery storage are becoming vital and integral parts of grid management.

There is a combination of factors at play in aiding utilities' financing requirements. These include rising debt issuance (based on green bonds), concessional funding, government budgetary support, equity sale, and asset divestment. Added push may come from private players' engagement through different business models explored by policy and regulatory authorities. This chapter takes a quick review of some of the key pointers and developments in this context.

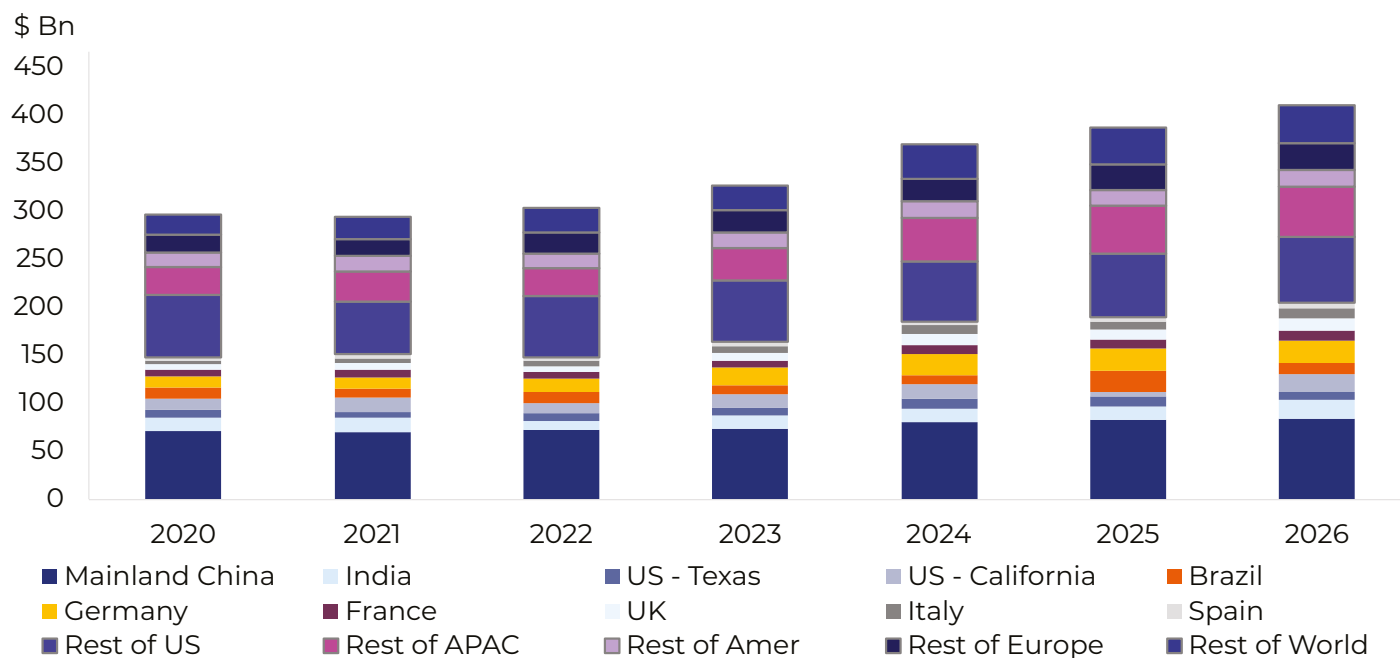


Grid Investment / Spend

Global power grid investment reached about \$326 billion in 2023 (BNEF, 2024). The investment outlook, based on the utilities' capital expenditure plans, points to an acceleration in total spending. BNEF estimates point to a 13% jump in grid investments between 2023 and 2024. By 2026, the total investments could be over \$400 billion. Notably, these investment estimates include high-voltage transmission and the lower sub-transmission or distribution networks. The latter segment assumes significance for many of the grid-connected renewable energy projects that require distribution grid connectivity.

The investment drivers are a combination of developments surrounding the power system, such as renewable power connectivity requirements, preparation for new demand/load, reinforcements for weather impact, and backlog in asset renewal and refurbishments, among others. The thrust on grid spending varies across the regions. Using BNEF's tracked grid investments covering 10 markets account for nearly half of the global grid investments and hold pointers about the possible direction in the investment commitments. This is more so because grid investment in these markets grew by 11% in 2023 and is projected to rise by 13% by the end of 2024. Growth in the rest of the world, in comparison, was 7% between 2022 and 2023.

Grid Investment across Major Power Markets/Regions



Note: (1) Country/power market investment data are based on respective network development plans tracked by BNEF. For other regions (referred to as Rest of the World, Rest of APAC, and the like, the data are based on BNEF's modelling.

(2) Grid investments are in real 2023 levels.

Source: BNEF

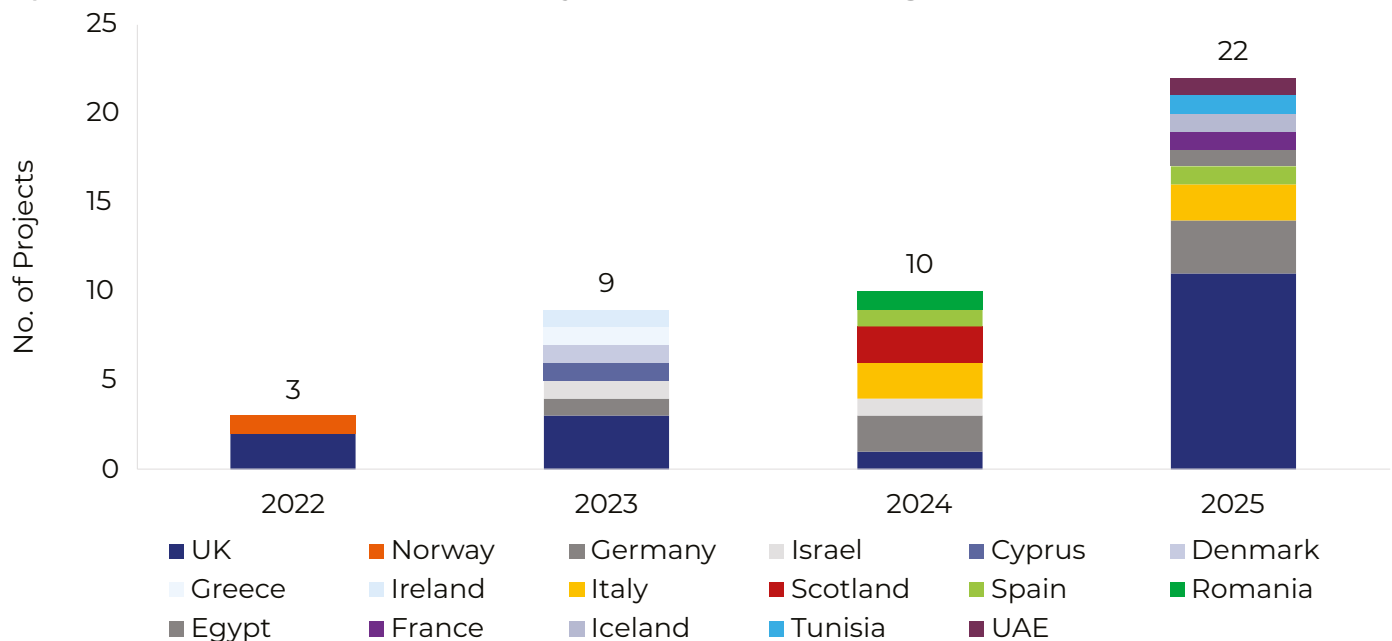


At 16%, growth in the German grid's capex was faster than any of the 10 tracked markets for the review period of 2020-2023. It was followed by Italy (12%) and Spain (11%) for the growth achieved in the same period. For the forecasted period of 2023-2026, the UK and Italy stand out for the rapid scale-up as indicated in the grid capex jump of 17% and 13%, respectively. In absolute terms of rise in investment spend, the Chinese grid capex ranks the highest as before, with a \$6.1 billion worth of year-on-year increase in planned investment of 2024, compared to 2023. Local conditions/constraints, such as procedural approvals, material supply chain, and the like may still influence the actual grid investments.

A few categories stand out in the planned power transmission investments. One of them

is HVDC power transmission technology, which has lately emerged as the preferred option for long-distance evacuation projects typical of renewable energy. There are more HVDC projects announced than the visibility afforded by the pipeline under development. A rising number of transmission utilities' long-term network developments refer to HVDC deployment. In 2023, about 46 new HVDC projects were announced for installation over the decade (DNV, 2024). Of particular note is the role of HVDC in tapping into offshore wind power projects, such as Germany's long-term plan of 35 new HVDC lines to connect over 70GW of offshore wind power by 2045 (Enerdata, 2024), and the UK's £60 billion HVDC supply chain framework (together with SSEN Transmission and ScottishPower Energy) to secure the cabling requirements till around 2030 (National Grid, 2024).

Pipeline of HVDC Transmission Projects in the EMEA Region

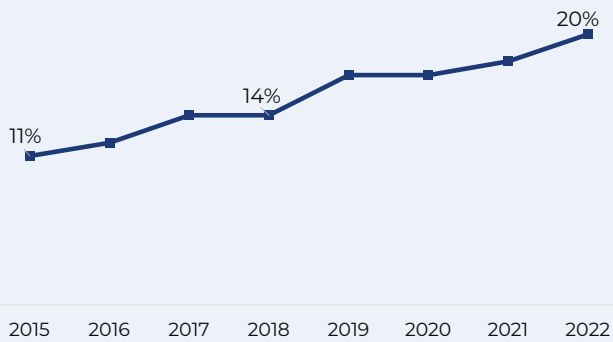


Note: Data is as of 2022. The project pipeline is indicative and is subject to change of plans based on the respective utilities' decisions

Source: Statista



Share of Digital Infrastructure in Total Grid Investments



Source: IEA

Big-ticket grid investments require multiple other areas of supporting infrastructure. One of them is digital infrastructure, a generic category that includes digitalisation implemented in multiple sub-segments of the grid asset base to extract optimal performance. Such investments complement the grid reinforcement and strengthening projects in power transmission. Commonly deployed areas of digitalisation in transmission networks include power transformers, substation automation, flexible alternating current transmission systems (FACTS), and advanced sensor-based control, monitoring and optimisation, such as in phasor measurement units. Though not exactly classified under the grid capex outlays, the share of digital infrastructure in total grid investments over the years (including sub-transmission and distribution) has been on the rise. With rising pressure on maintaining service reliability standards while maintaining costs within approved levels, digitalisation is likely to play an even more important role than before.

Energy storage is another critical allied area of grid infrastructure, growing rapidly as an asset class for both renewable energy developers and the TSOs. In many countries, TSOs may not be allowed to take investment positions in grid-scale storage systems. Yet, the investment case gets stronger by the day, with TSOs and power system regulators facilitating the role of standalone grid-scale battery storage units in the grid-connected power. As of 2023, battery-based storage attracted about \$40 billion in investments – of which 85% was concentrated between the Chinese and US power markets. Many other markets, especially the European, are expediting measures to align batteries not only in the wholesale power market transactions but also for grid flexibility and its ancillary services.



Focus on Grid-scale Battery Storage Capacity in Select Power Markets Worldwide

Pointers on Investments in Grid-scale Storage



US

Independent System Operators such as NYISO, CAISO, and ISO-NE have enabled battery storage to participate in the grid ancillary services market.

Led by grid-scale storage, a six-fold rise in demand is projected by the end of the decade.



UK

Sophisticated energy market design includes a well-established and diverse revenue stack for BESS. Upgrades to the National Grid ESO's Open Balancing Platform support the bulk dispatch of battery storage in real time.

Public funding support/commitment worth £20 billion to establish the battery industry by 2030.



Australia

Daily spot markets for power and system frequency control services offer diverse revenue streams.

The federal government has agreed with states to establish a Capacity Investment Scheme, allowing battery storage developers to tender to fill expected reliability gaps



Italy

TSO-led (Terna) storage tenders worth 71GWh by 2030.

Twelve- to 14-year fixed-price long-term contracts are offered, indexed to inflation, with Terna as the counterparty.

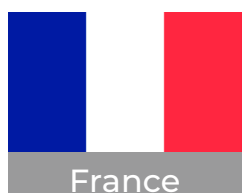
The government will soon tender for utility-scale storage capacity and issue a regulated framework for BESS investments.



Germany

Favourable market conditions, including some grid fee exemptions and construction subsidies, to promote grid-scale battery storage investments.

Energy storage can participate in day-ahead and intraday power markets.



France

Tax credits to help facilitate grid-scale battery storage investments.

More BESS projects have prompted the energy regulator to reopen a postponed auction for demand response power



Japan

Multiple revenue streams for BESS, including rolling weekly and day-ahead power markets.

Battery storage can compete for three-hour blocks in capacity auctions. For a period of 20 years, winners will receive subsidies equivalent to the "fixed costs" of a qualifying project, which would include a stand-alone facility.

Source: EY



Resource Mobilisation

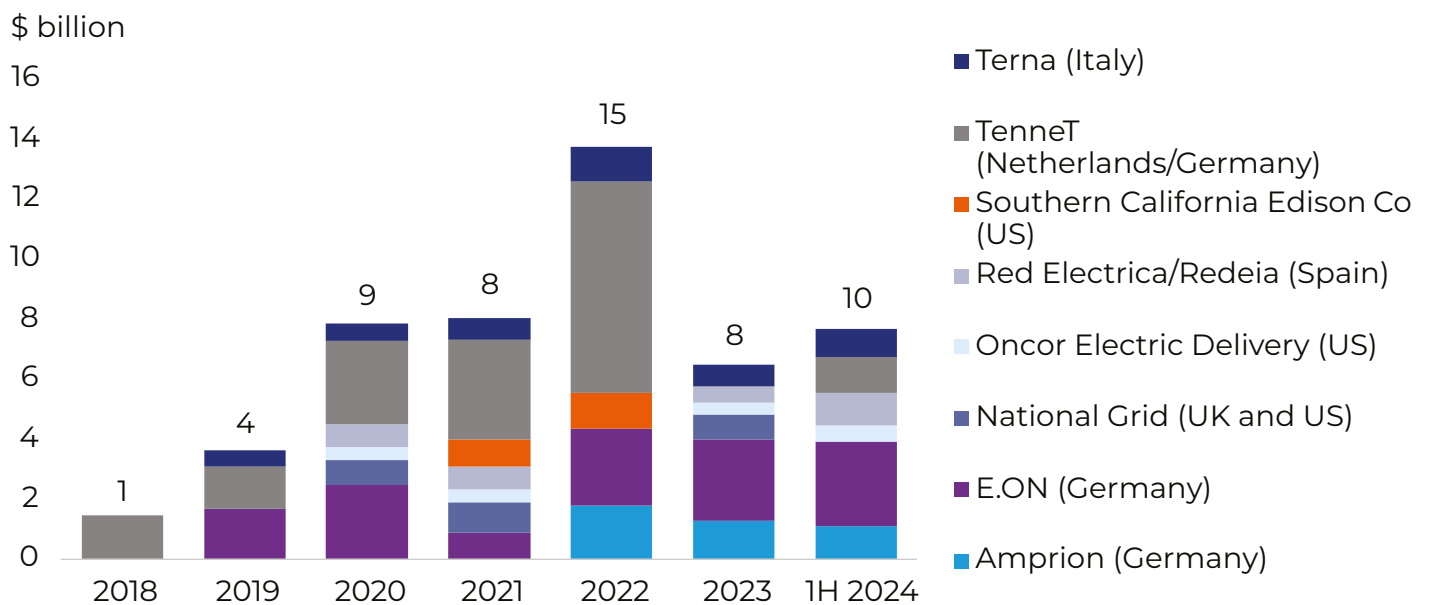
The unprecedented investment requirements across the grid networks mean that the TSOs must raise massive amounts of debt and equity. Most of the entities are privately owned, and the choice of financing route is determined accordingly. There is reliance on capital markets, and profits are subject to the returns determined by the regulatory authorities. The regulatory approvals of grid fees and return on equity are, in fact, key determinants of the utilities' creditworthiness.

In European and US utilities, borrowings typically contribute about 60% of the investments. This is equally applicable to other regions due to private ownership in the business. In addition, public financing is available through government budgetary support, municipal authorities' funding, international development banks, and multilateral financial institutions. Debt funding, while a key part of the equation, is also sensitive to the interest rate trajectory. If debt servicing

cost exceeds the approved returns, the grid utilities risk a loss. Thus, for many utilities, the higher interest rates of 2022 and 2023 have also set the basis for a rate revision that justifies the investment and profitability.

In recent years, green bonds or sustainability-linked bonds have become increasingly important for capital raising by energy utilities, including those related to transmission and distribution grids. Green bonds are among the dominant bond issuance routes in advanced and emerging markets, reflecting the role of sustainability and energy transition. Energy utilities (aggregate, in addition to the ones in transmission) have had a predominant role in Green Bonds. World Bank updates show that under the broader category of Green, Social, Sustainability and Sustainability-linked (GSSS) bonds issued globally, over 80% of utilities' total bond issuance amount as of March 2024 has been from Green Bonds (World Bank, 2024).






Sustainability-linked Bonds Issued by Grid Utilities by Year of Issuance

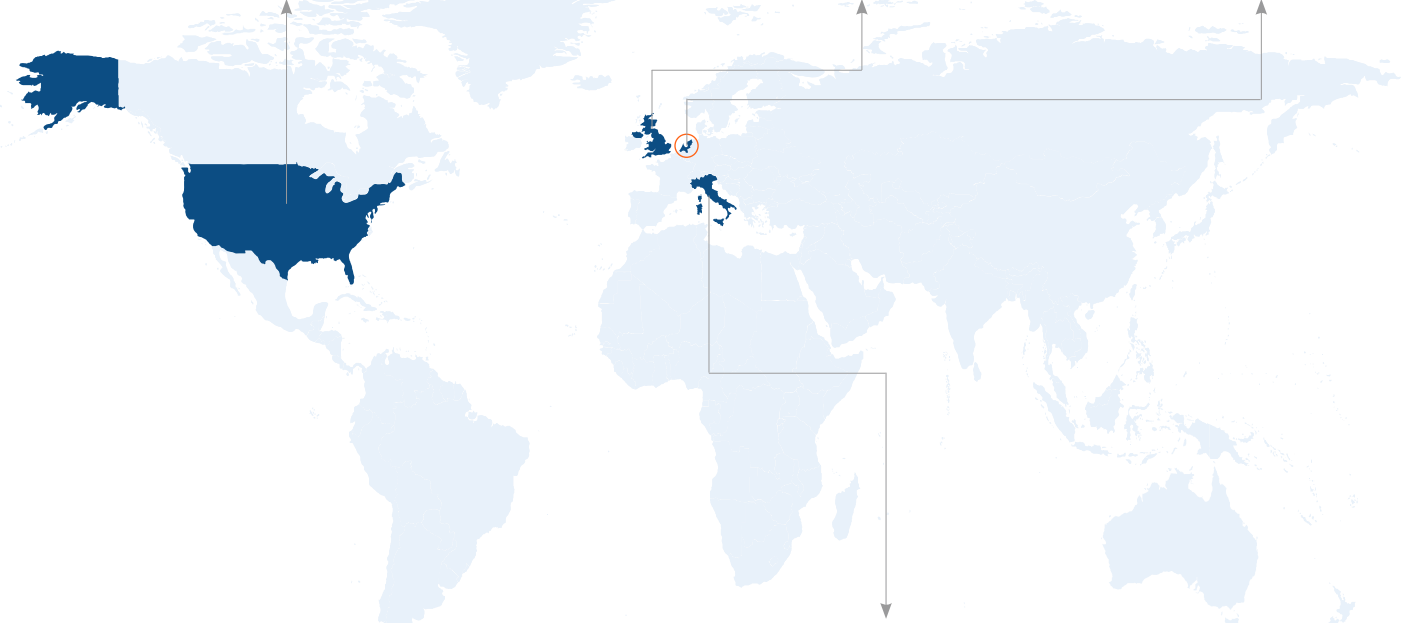



Grid utilities and TSOs exploring multiple options at the same time. The impending capex surge has fuelled a divestment of non-core assets. Lately, many TSOs, utilities, and/or energy holding companies have sold their non-core assets to shore up resources required for the planned rise in capital expenditure. In many cases, asset disposals have been undertaken as part of measures to reduce leverage and mitigate balance sheet pressures. The TSOs facing credit rating pressures (such as Italy's

Terna and Red Electrica of Spain), too, have taken the same route. The momentum of asset disposals may sustain for a while, as many utilities are inclined to hive off the non-core segments and avoid additional debt issuance as much as feasible (Utility Dive, 2023). An additional point in favour of asset disposals is the regulatory authorities' reluctance to implement steep grid tariff hikes to guard consumer interests.

Select Examples of the Sale of Non-Core Assets to Aid Capex Plans

TSO / Utility	Asset Sale	TSO / Utility	Asset Sale	TSO / Utility	Asset Sale
	Finalised the sale of the gas distribution business to Enbridge as of September 2023 (Dominion Energy, 2023).		As of September 2024, it completed the divestment of its gas transmission and metering business, transferring the ownership to Macquarie (Energy News, 2024).		As of May 2024, it was in multiple discussions to dispose of its German grid assets. The operator may consider either listing its German operations or selling them to a third party (Reuters, 2024).
	In April 2024, it announced the sale of its 50% ownership interest in Pioneer Transmission to John Laing Group (Duke Energy, 2024).				
	As of October 2024, the sale of its 50% interest in two offshore wind projects marked a full exit from the segment (Utility Dive, 2024).				



TSO / Utility	Asset Sale
	In April 2022, it signed an agreement with CDPQ to sell 100% of its Latin American power transmission assets (Terna, 2022).

Source: Dominion Energy, Duke Energy, Utility Dive, Terna



In parallel to asset disposal, various other measures are underway to supplement utilities' financial resourcing. Terna, for instance, issued large volumes of hybrid debt securities whose equity component allows the raising of funds while protecting credit ratios. The Dutch TSO TenneT received government help in recapitalisation. The German government has been considering consolidation of the country's fragmented power transmission structure to help boost the long-term funding in the business (Scope, 2023).

The government's role in transmission has also been through grants and related concessional funding. The US federal funding under the Inflation Reduction Act (IRA) and Bipartisan Infrastructure Law, in addition to the Department of Energy's project funding, are notable examples. There are other examples, such as India's, where government funding is integral to the dedicated transmission corridors

planned for renewable power projects. In the European Union, the Connecting Europe Facility (CEF) allocated \$4.6 billion during the period 2014-2023 for cross-border transmission projects.

Government grants are generally dovetailed by multilateral funding in power transmission projects. In this investment space, a few multilateral development banks, such as the European Investment Bank (EIB) and KfW, have been the most active recently. European HVDC interconnector lines have been a major focal point in the EIB's funding areas. In addition, grid upgrade projects are another key area of focus in some of EIB's recent funding – notable examples of 2024 being \$700 million for Iberdrola in Spain (power distribution) (BNEF, 2024), a co-financed project worth €600 million for a German grid upgrade project in April 2024 (SEI, 2024) and Terna's €400 million grid reinforcement project in Italy (EIB, 2024).

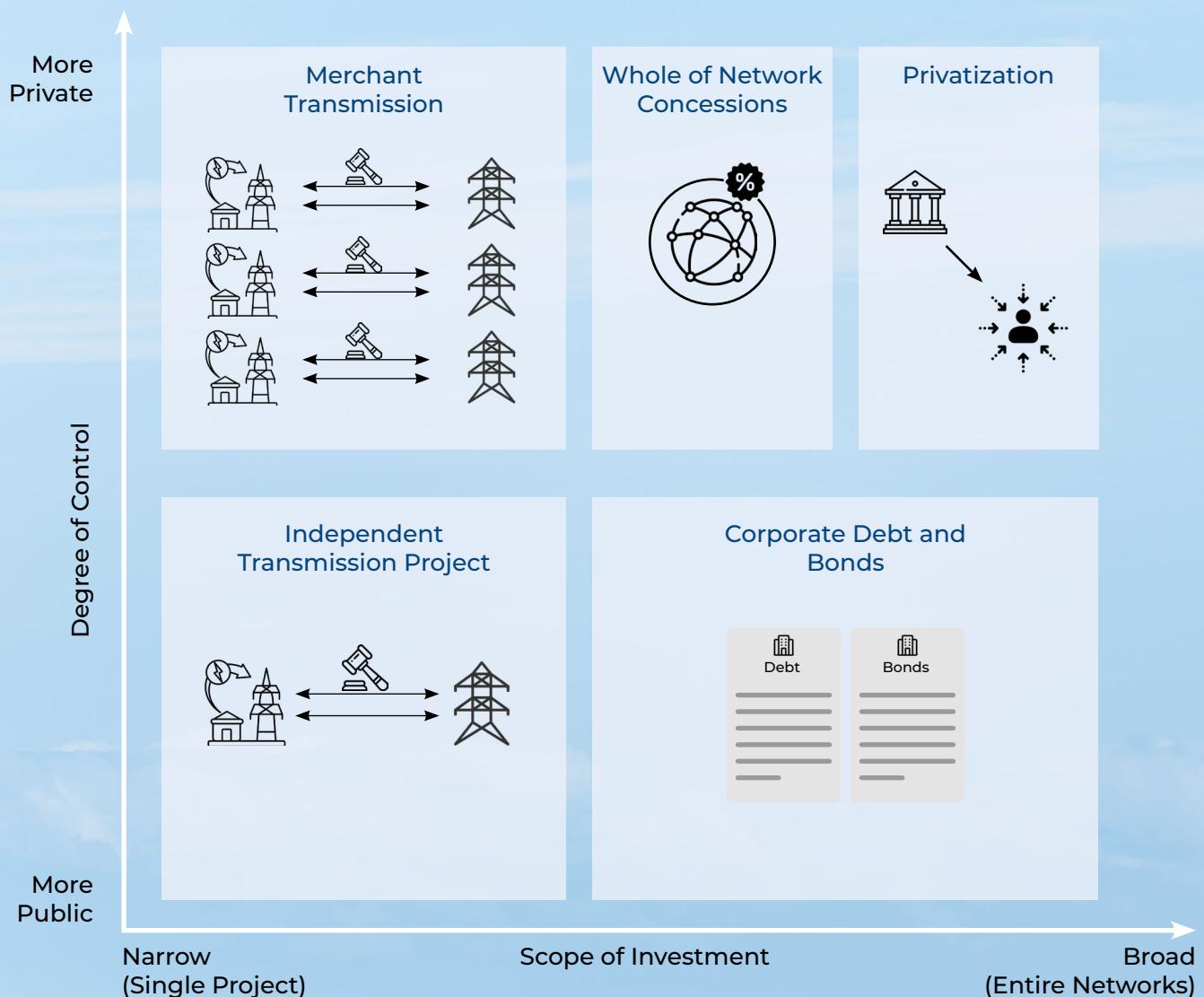


Business Models for Private Investment

In a discussion on investment related to power transmission, the reference to business models aims to point to some of the business arrangements in which entities participate in building the assets. While the incumbent utilities are already placed to augment the capacities, policy and regulatory authorities have enabled other avenues to allow market entry. The regulatory oversight and the other requirements are modified accordingly. Such

measures can be seen as a continuum of the shift towards privatisation in the grid utilities business over the years – starting with the unbundling of integrated utilities to gain efficiencies. Many models or arrangements are thus at play worldwide. In the present discussion, we broadly review these under – merchant models, independent power transmission and offshore transmission (specific to the UK).

Illustration of Business Models in Private Investments for Grid



Source: BNEF

The merchant power transmission model has been implemented in a few markets to help expedite the network development process. Merchant transmission projects (MTP) typically involve private developers who would build the project without the usually regulated revenue guarantees or long-term contracts with utilities or government authorities. The incentives lie in the potential arbitrage opportunity between power markets or regions with differing electricity prices. In this regard, the revenue streams tend to be volatile due to the dynamic market forces. The trade-off, however, is that they are less regulated and can side-step the barriers generally faced by regulated developers in the conventional/regulated settings.

The US power market is an important example of the role of MTPs. Unlike Europe, the US market has been lagging in the implementation of interregional HVDC transmission. Rising renewable energy penetration and grid congestion have made HVDC-based links even more critical for the US power system. Against such a backdrop, it is noteworthy that the MTP developers are driving almost all of the country's HVDC project pipeline. Among other factors, it is seen that the MTPs of these US projects have circumvented the issue of cost allocation because the lines would be paid for by the individual power generators subscribing to the transmission capacity (S&P Global, 2023).

Select Major Merchant Power Transmission Projects in the US

	Company	Voltage (kV)	Line Length (miles)	Expected year	Cost (\$B)
New England Clean Power Link	Transmission Developers	320kV DC	154	2029	1.60
Champlain-Hudson Power Express	Transmission Developers	320kV DC	339	2026	6.00
Southern Spirit Transmission	Pattern Energy Group LP	500kV DC	400	2027	2.50
Grain Belt Express	Invenergy Transmission LLC	600kV DC	800	2028	7.00
SOO Green Renewable Rail HVDC Transmission	SOO Green Renewable Rail LLC	525kV DC	350	2029	2.50
SunZia Southwest Transmission	Pattern Energy Group LP	525kV DC	550	2026	2.00
TransWest Express	TransWest Express LLC	500kV DC/AC	732	2027	3.00
Southline Transmission	Grid United LLC Black Forest Partners LP	345kV AC	280	2027	0.80
North Plains Connector	Grid United LLC ALLETE Inc.	500kV DC	395	2029	2.50

Note: Data is as of September 2023





Source: S&P Global



To be sure, the MTP model is subject to the suitability offered by the local power market norms. The business model presents one option through which policy authorities can engage private players to secure the investments rapidly and get the capacities online at the most feasible prices. For the most part, private participation in power transmission projects has often been through a route of getting competitively bid projects. The structures, in terms of contractual obligations and risk-sharing, vary. However, the goal is to attract private developers and operators to get the required transmission capacities faster than the historical rate of progress.

The model of independent power transmission projects (IPTP) gained currency in emerging market economies as policy/regulatory authorities sought rapid privately led projects for capacity addition. IPTPs are privately financed, developed and operate under independent ownership outside of the government-owned utilities. Some of the notable characteristics of such an arrangement include – public private partnership (PPP) ventures with the private entity securing a contract under design, build, finance and operate (DBFO) structure, long-term concession agreements to govern the terms, tariff-based revenue stream and potential scope for project-based financing.

Notable Examples of Independent Power Transmission Projects

	<p>Ireland / UK</p> <p>The 190 km long Greenlink HVDC interconnector (Ireland – UK) line is owned by Partners Group, which is responsible for building, developing, financing and operating the asset (Greenlink, 2021).</p>
	<p>Brazil</p> <p>As of April 2024, the federal government officially signed three transmission concession contracts worth R\$217 billion involving over 4,000 km of line length across the country's three provinces (Brazil Government, 2024).</p>
	<p>India</p> <p>As of June 2024, the government approved schemes worth \$1.6 billion for transmission projects based on tariff-based competitive bidding (Enerdata, 2024).</p>
	<p>South Africa</p> <p>As of May 2024, the state-owned utility Eskom was considering an auction worth \$21 billion for transmission projects totalling over 9,000 miles of line length (Oil Price, 2024).</p>

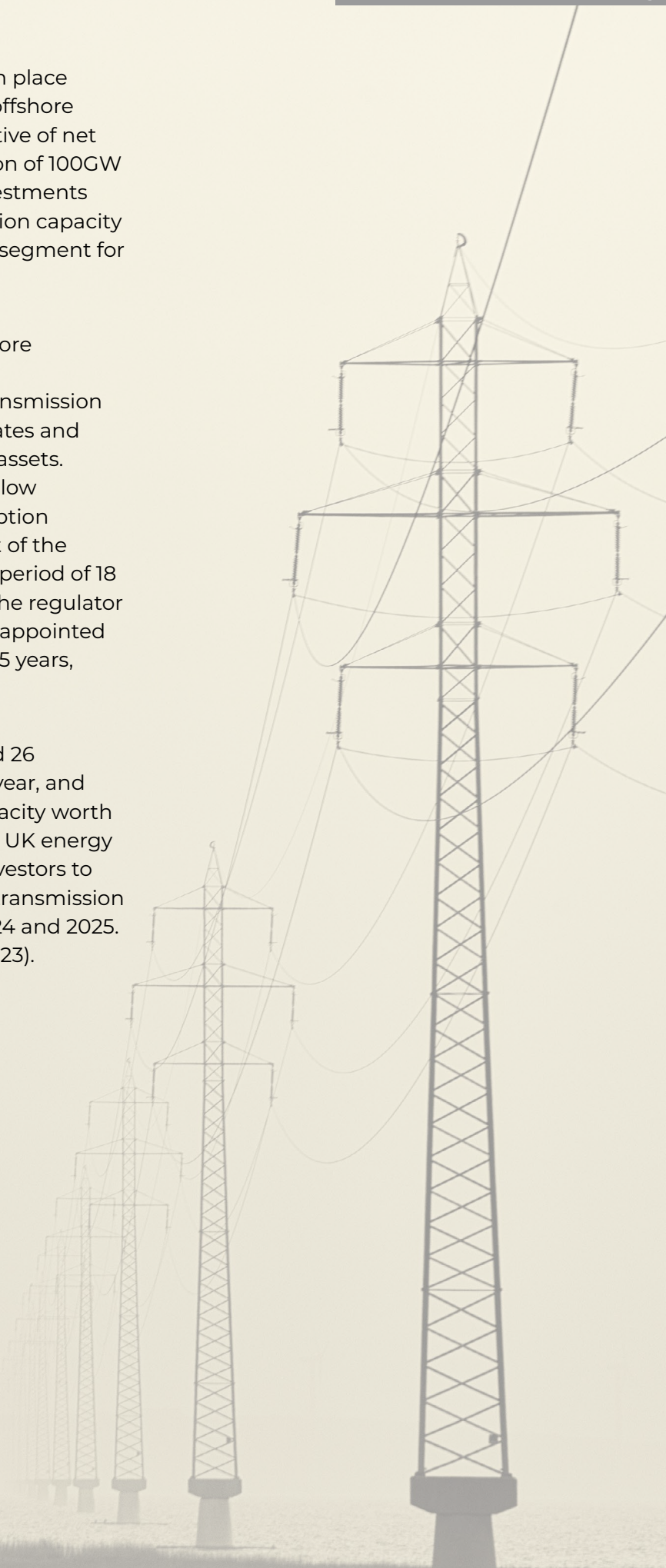
Source: Brazil government press release, Oil Price, Greenlink, and Enerdata



In the UK, a variant of the IPTP model has been in place since 2009 to enable private investments in the offshore wind power segment. The country's policy objective of net zero by 2050 relies on a potential capacity addition of 100GW from its offshore wind energy resources. The investments required to evacuate such a quantum of generation capacity are huge, hence the need for competition in the segment for efficiency (UK Government, 2023).

The UK's regulatory framework provides an offshore transmission licence for a successful bidder of a competitively bid asset. The selected offshore transmission owner, also referred to as OFTO, thus owns, operates and maintains the designated offshore transmission assets. Also, to de-risk project delivery, the regulations allow the generation project promoters to retain the option of delivering the transmission connection as part of the construction process and operate the asset for a period of 18 months. It is during this 18-month window that the regulator carries out the competitive bidding process. The appointed OFTO receives a guaranteed revenue stream of 25 years, subject to the availability of the assets.

By the end of 2023, the OFTO network comprised 26 licensed OFTOs, compared to 22 in the previous year, and supported a total offshore power generation capacity worth 11.8GW (Crown Estate, 2024). As of June 2023, the UK energy regulator Ofgem put out a call for prospective investors to bid for an estimated £7 billion worth of offshore transmission that could be auctioned in bidding rounds of 2024 and 2025. This comprised about 10 OFTO assets (Ofgem, 2023).



UK's Offshore Transmission Owner Licences by Bidding Rounds

OFTO Tender Round	Offshore Generation Project (Capacity)	OFTO Licence Granted
9	Seagreen Phase-1 (1,140MW)	-
8	Hornsea 2 Wind Farm (1,368MW)	-
7	Mory East (900MW)	-
	Triton Knoll (857MW)	-
6	Hornsea 1 (1,218MW)	Diamond Transmission Partners Hornsea One Ltd.
	Beatrice (588MW)	TC Beatrice OFTO Limited
	East Anglia 1 (714MW)	TC East Anglia One OFT Ltd
5	Dudgeon Offshore Wind Farm (402MW)	TC Dudgeon OFTO Plc
	Race Bank Offshore Wind Farm (573MW)	Diamond Transmission Partners RB Ltd
	Galloper Wind Farm (340MW)	Diamond Transmission Partners Galloper Ltd
	Walney Extension Offshore Wind Farm (600MW)	Diamond Transmission Partners Walney Extension Ltd
	Rampion Offshore Wind Farm	TC Rampion OFTO Limited
4	Burbo Bank Extension (258MW)	Diamond Transmission Partners BBE Ltd
3	Westermost Rough (205MW)	TC Westermost Rough OFTO Ltd
	Humber Gateway (219MW)	Humber Gateway OFTO Limited
2	London Array (630MW)	Blue Transmission London Array OFTO Ltd
	Lincs (270MW)	TC Lincs OFTO Ltd
	Gwynt y Môr (574MW)	Gwynt y Môr OFTO Plc
	West of Duddon Sands	WoDS Transmission Plc
1	Robin Rigg East and West (180MW)	TC Robin Rigg OFTO Ltd
	Gunfleet Sands 1 and 2 (173MW)	TC Gunfleet Sands OFTO Ltd
	Barrow (90MW)	TC Barrow OFTO Ltd
	Walney 1 (184MW)	Blue Transmission Walney 1 OFTO Ltd
	Ormonde (150MW)	TC Ormonde OFTO Ltd
	Walney 2 (184MW)	Blue Transmission Walney 2 OFTO Ltd
	Sheringham Shoal (315MW)	Blue Transmission Sheringham Shoal Ltd
	Greater Gabbard (504MW)	Greater Gabbard OFTO Plc
	Thanet (300MW)	Thanet OFTO Ltd

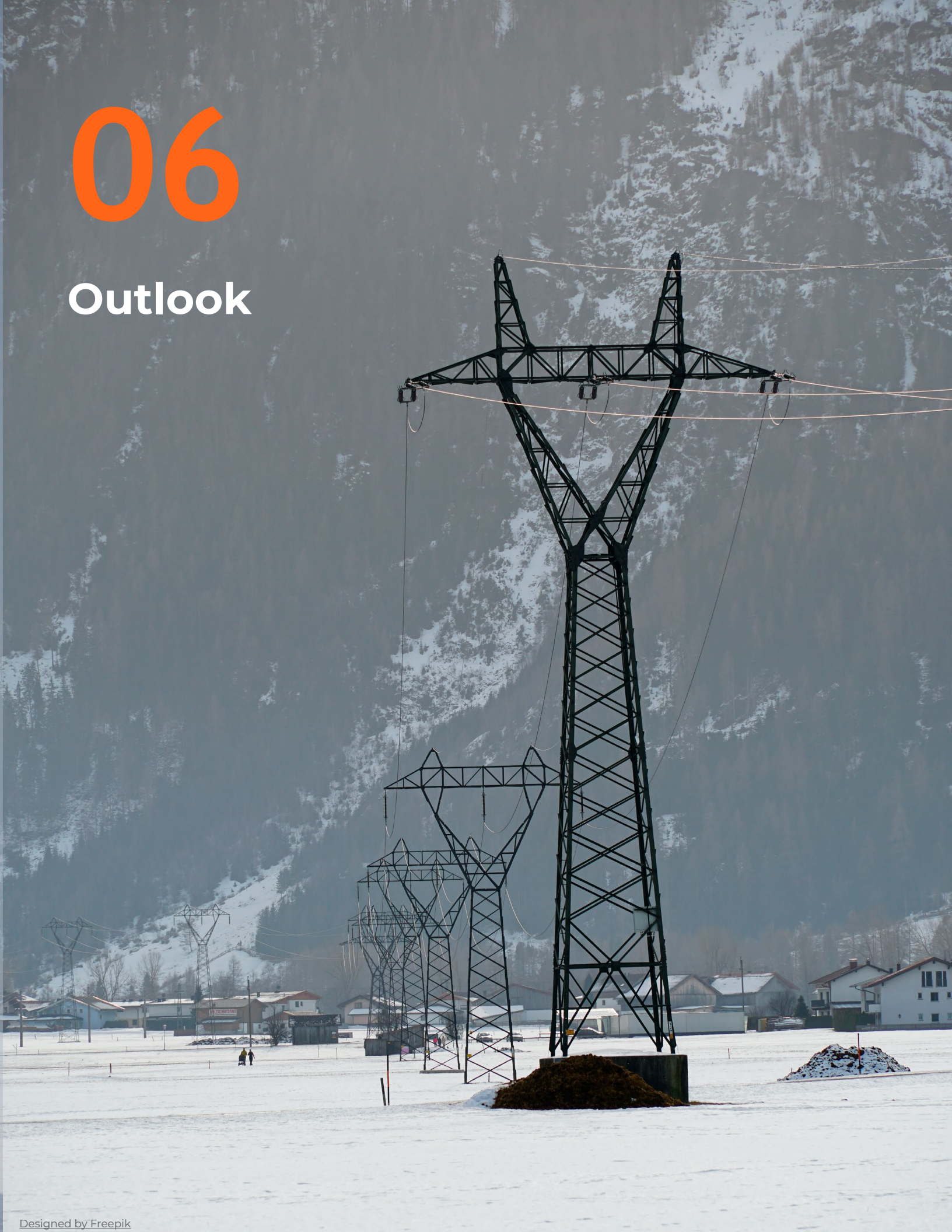
Note: Blank entries under licences indicate ongoing procedures, such as the invitation to tender.

Source: Ofgem



06

Outlook



The grid infrastructure is receiving sharper attention than ever as energy transition investments rise in momentum. The spikes in grid capex, renewed tariff requests, tariff approvals, and enhanced funding all point to the same direction of heightened activity in the grid network to catch up and meet the foreseeable demand. Policy and regulatory measures are also enabling the process,

whether in financial support or liberalised market entry for investments. The efficacy of all such steps would be weighed against the timeliness of delivery. As much as feasible, the availability of grid infrastructure must synchronise with the upcoming demand. Taking all this together, this section aims to review and summarise some of the salient points shaping the outlook in the power transmission industry.

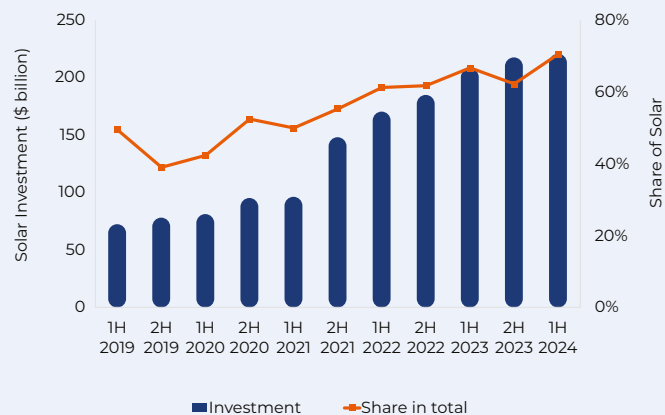
Solar Power Driving the Upcoming Grid-connected Renewables

Solar power is likely to drive the rise in renewable energy deployment. A strong project pipeline, steady investment commitment, and favourable techno-commercial parameters made solar power projects a preferred choice among the competitive renewable energy options. For most grid utilities, the implications of the rise in solar power (along with other renewable generation) on network preparedness, upgrades, and expansion are understood and increasingly provisioned in network development plans. For prospective investors and/or developers, however, the surge in grid-connected solar projects (as with wind alongside), there are a few notable pointers.

Progressively, there is a strong preference for co-located battery storage installations, led mainly by solar PV and battery combinations. A weak grid integration in most markets makes co-located batteries attractive in managing grid scheduling. An added benefit is the lower capital outlay and land and grid infrastructure optimisation. The US market's project pipeline for 2024 has a 70:30 split between co-located and standalone battery assets (Energy Storage News, 2024).

Battery storage co-located with a solar PV plant would enable grid services such as dynamic containment, besides mitigating the

Solar Power Investments Globally



Source: BNEF

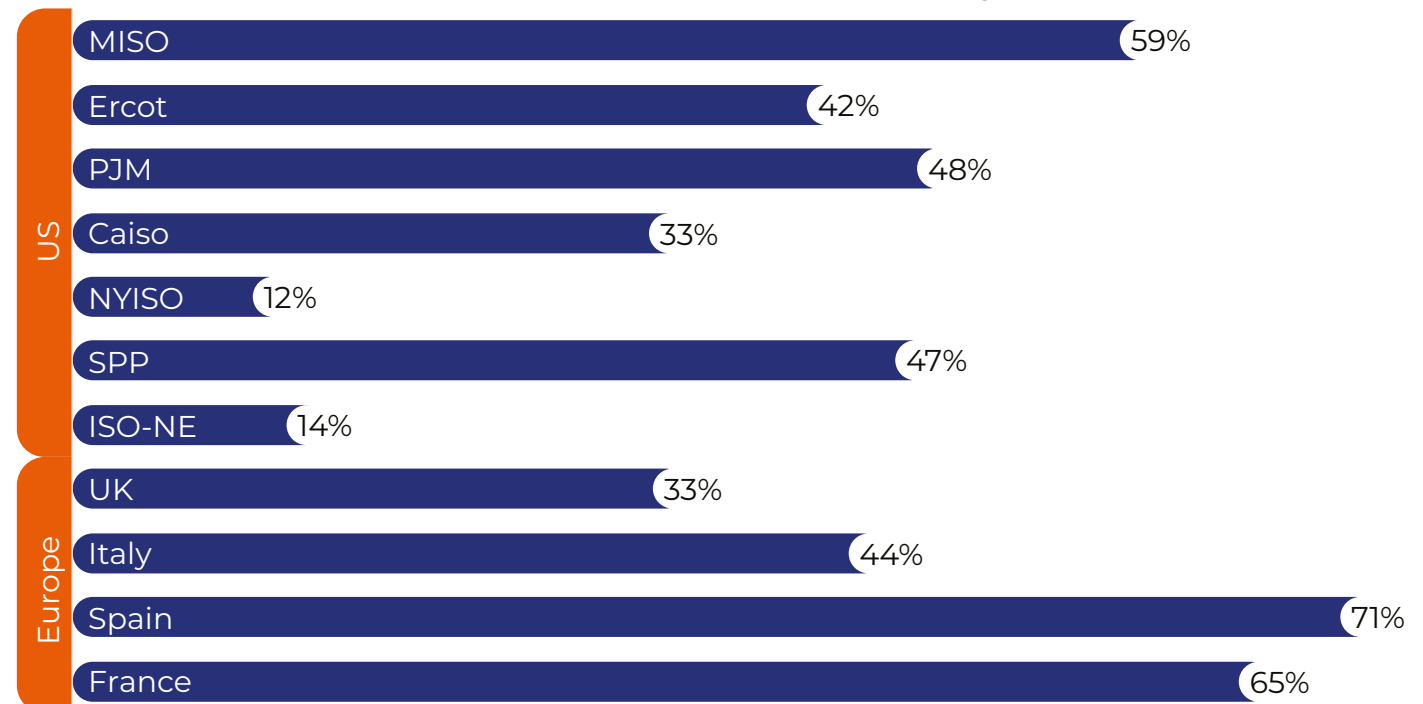
profitability risks that arise from excess supplies in the grid. Project pipelines in major battery storage markets, such as the US and UK, show a progressively rising interest in solar-plus-storage projects. The relatively higher investment returns in such projects potentially outweigh the complexities (such as separate permits, feasibility studies, etc.). Some investment funds have also adopted the retrofitting route in battery collocation. In 2023, NextEnergy Solar Fund initiated retrofitting of storage to its solar PV portfolio for better returns. Grid uncertainty is potentially one of the major driving factors in the collocated solar projects. It may partially solve the more significant and fundamental problem of grid connection request queues.



Globally, solar power projects in some of the leading power markets drive the pile-up in developers' grid connection requests. Shorter lead times in the commissioning of solar power projects make it even harder for the TSOs to

arrange connectivity in an already congested grid. At least in the near to medium term, solar power pipelines may aggravate the issue. It may also enhance the role of storage in grid flexibility.

Share of Solar Power in Grid Connection Queue of Select Major Power Markets



Source: BNEF

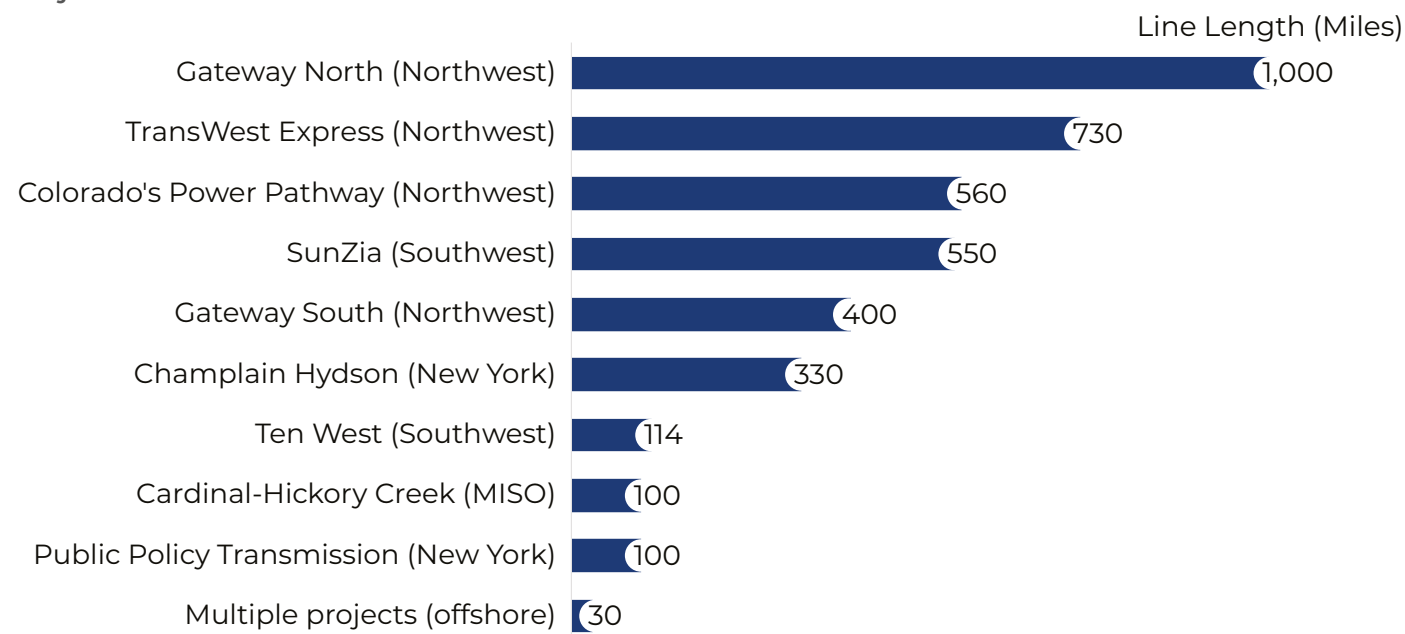


Capacity Buildout Chasing Targets and Ageing

Various projections point to an investment outlay of \$400 billion in the global transmission project pipeline over the next 5-10 years. The investment quantum and its schedule may change with time. For stakeholders, especially investors and developers, the pointers lie in the capacity additions that suggest possible easing in bottlenecks. There might be a mixed picture in this regard. For example, BNEF's Net Zero scenario entails doubling the global annual grid spending by 2030. A few markets (such as California ISO and the UK) make the cut in this parameter. Most of the other markets are lagging in the investment levels aligned with net zero goals fixed by the respective authorities.

In effect, the TSOs' grid development plans are about managing the rising network demands. The demand drivers are essentially the same for all transmission utilities, especially those in advanced economies. Among the most discernible pressures on TSOs and system operators is the addition of renewable power capacity and the grid connection queue it causes. In the US market, this is likely to persist for some time. As of April 2024, about 2.2TW of generation capacity, a multiple of the whole country's installed power generation capacity, was in the queue for pending grid connection. (S&P Global, 2024).

Major Transmission Lines Under Construction in the US



Note: Survey data as of September 2023

Source: Statista



Despite the gradual improvement, it will be a long way to ease the crunch. In the European markets, the lack of timely capacity often manifests in grid curtailments or even the occasional pause for new grid connection requests. Globally, grid curtailment has risen in the high renewable energy penetration power markets, such as in the California ISO, Germany and the UK. The impact on renewable projects can vary. In Germany's framework, for instance, there is total compensation for curtailment. In Texas, there is none. Worsening grid congestion could also hinder the growth of power market transactions. Cross-border transmission links, as in the European Union, could significantly contribute towards renewable energy-led interconnected power markets. The planned transmission hub in the North Sea region underscores the untapped potential.

Beyond grid connectivity for the new generation capacities, an equally important investment driver is the reinforcement and refurbishment of existing network assets. Grid reinforcement

could lead to capacity building in some markets. France is one notable example of a power market where grid expansion works have been comparatively lesser than in other regions, and asset replacement and modernisation works account for a large part of the utilities' spending. Adding to the complexity, service reliability is not the only reason for the ongoing grid reinforcement works.

More than ever, the ageing and weak grid network foundations are prone to disruption from recurring extreme weather events. A few operators are thus recommending underground transmission lines despite the cost disadvantage compared to those erected overhead. In a few other cases, outdated transmission systems stand at odds with the spiralling electricity demand. For instance, in the US state of Georgia, the booming demand for data centres outstripped the operators' and utility's plans, with the latter struggling to keep pace without a significant overhaul. (WP, 2024).

Transmission Buildout in EU's Ten-Year Network Development Plan as of 2022

Technology	Line Length (route km)	Transformation Capacity (MVA)
AC	18,000	120,651
DC	25,000	38,806
Total	43,000	160,457

Note: (1) Data includes delayed projects presently under construction or in planning stages. (2) EU's Ten-Year Network Development Plan of 2024 is still under deliberation.

Source: ENTSOE



Likelihood of Systemic Delays

In the US market, transmission projects have been prone to increasing delays. In 2023, just about 250 miles were commissioned, whereas an average of 2,000 miles were installed between 2012 and 2016 (Business Insider, 2024). A fragmented business and limited coordination led to such a pass. Some recent policy and regulatory measures aimed at sorting out the logjam may address it. For instance, the US Federal Electricity Regulatory Commission (FERC) directed the regional grid operators, states, and utilities to develop 20-year transmission plans to meet the upcoming demand and an agreeable way to pay. FERC's same directive also made it harder for the states to back out of the commitments.

Implementing comprehensive and systemic changes in transmission project implementation will take much longer. Examples of constraints in the US market are also seen in European projects. With multiple stakeholders and jurisdictions involved, it is often beyond TSOs to compress schedules. An example in point is the construction of the 340km HVDC link of Ultratnet in Germany, which requires 13,500 permits. (BNEF, 2024). Incidentally, over a quarter of the European transmission projects marked as projects of common interest for priority funding also face delays primarily due to the permitting procedures. (IEA, 2023).

Permitting and procedural processes will likely be subject to the same pressure points in the near term as they have been over the past years. In comparison, emerging market economies, especially China and India, have much shorter lead times, on average, in commissioning transmission lines. Centralised decisions and interventions (e.g., dedicated power evacuation corridors) have recently been among the most critical factors. Comparable measures in advanced economies could be traced to the steps undertaken towards facilitating private investments (merchant lines in the US or the

OFTO regime in the UK) to expedite projects in select sub-segments. However, investors and developers must factor in the inherent uncertainty involved in the transmission project pipelines.



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Aligning Grid Tariffs for Capex

The spike in grid capex is forcing a rethink about incentives. There are some early signs that the TSOs may find acceptance for revised grid rates. As of August 2024, two system operators of the US, namely, the Midcontinent Independent System Operator (MISO) and the Southwest Power Pool (SPP), sought federal regulators' approvals for proposed changes in the tariff structure. The tariffs would help advance \$1.7 billion in investments and enable 30GW of new generation capacity (Utility Dive, 2024). Similarly, many other US and European utilities have rate revision requests in the queue before the respective authorities to match mounting capex requirements. The justification for the tariff revision is more substantial than before. In Germany, the network operator's announcement on revised grid tariffs of 2024 was followed by a government subsidy worth €5.5 billion to help minimise the impact on end consumers (Clean Energy Wire, 2023). Regulators in Austria and Switzerland have similarly authorised higher grid tariffs (Scope, 2023).

The higher tariffs may just help catch up with the past years of lagged tariff revisions. Meanwhile, TSOs must manage the rise in development costs due to logistics, material supply chain, and wages, among other things. The recent softening of interest rates worldwide may help utilities planning to raise debt capital. Many have had to postpone their borrowings earlier, as higher costs vis-à-vis approved returns posed a barrier. In addition, non-core asset disposals help expand the avenues for TSOs to channel financial resources. More utilities are expected to join the fray in non-core asset disposals to mitigate balance sheet pressures amidst weak credit ratings.

To a significant extent, the respective governments and policy authorities may also be responsible for supporting the transmission capex. Policy-level action may take varied forms,

not just direct funding support, as seen in Germany. Enhanced private participation and enabling market entry for competition are two avenues through which policy action could drive investment spending in the business.



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07

Regional Market Overviews

GERMANY

Germany's rapidly growing renewable energy pipeline, especially in offshore wind power, could face a barrier in terms of lack of transmission connectivity. The country's transmission network has been caught in a lag against the shifting energy mix and rising power demand. There is thus a collective push to capacity addition by the TSOs, policy authorities and the regulator. While legacy challenges abound through permitting delays and procedural approvals, the transmission project pipeline has expanded drastically. The investment outlook of the German transmission industry is one of a drastic jump in capex, partly supported by the approved returns and, on occasion, government funding.



GDP
(Current Prices, \$ 2023)

4,527 Bn

Projected Average GDP
Growth 2024-28

0.8%

10-Year Govt. Bond Yield
(12-Month Rolling Average)

2.3%

Country
Credit Rating

AAA

Renewable Energy
Share

49%

Total Transmission Line
Length (Km)

35,000

Note: Renewable Energy Share excludes hydropower



Transmission Network

The German power transmission network consists of about 35,000 km of total line length, with voltage levels predominantly at 220kV and 380kV AC. In addition, it has interregional transmission links based on HVDC, which play a vital role in cross-border power market transactions. Germany's position as a transit country between the Western and Eastern European power markets makes its transmission infrastructure even more important (Federal Ministry, 2024). Network expansion has been a recent area of focus due to the pressure of renewable energy integration. Otherwise, long-term growth has been meagre, signifying a typically mature and industrial economy. Between 2014 and 2022, the line length registered a CAGR of 1.04% (Global Transmission, 2023).

The network needs new lines and equipment and refurbishment to extend its useful life. With rising renewable energy penetration and grid congestion/curtailment issues, the urgency of the matter has come to the fore. Policy-level interventions, such as expediting the grid expansion approvals, seek to address some of the persistent issues (Clean Energy Wire, 2024). Among the major transmission projects currently under development is the €2.8 billion NeuConnect Interconnector line, also the first power cable between the UK and Germany. Construction started in May 2024 and is scheduled for commissioning by 2028 (S&P Global, 2024). The regulatory approvals for adding transmission lines in 2024 and 2025 amount to 1,800 km and 1,600 km, respectively, in line length (Clean Energy Wire, 2024).

Lately, among the issues involving network growth, the regulator and TSOs have had to come to terms with the merits of underground vis-à-vis overhead lines. Several federal and provincial policy authorities recommended underground lines to avoid public opposition and disruption during extreme weather events. The regulator, however, concurred with the

TSOs' views, favouring overhead lines due to their lower costs (€35 billion in savings) (Clean Energy Wire, 2024). Cost is a key factor, as the grid fees (including distribution) typically make up about a quarter of the final consumer's charges, which makes regulators generally reluctant to entertain tariff revisions.

Transmission Line Length

TSO	Line Length (circuit km)
Amprion	10,087
TransnetBW	3,200
50Hertz	9,850
TenneT	11,863
Total	35,000

Note: TenneT's line length is a derived estimate obtained by deducting the line length of other TSOs from a total of 35,000 km reported by the Federal Ministry for Economic Affairs and Climate Action

Source: Respective Transmission System Operators

Cross-border Transmission Linkages

Country Linkage	TSO	About the Linkage
Germany - Denmark	50Hertz (Germany) Energinet (Denmark)	170 km long, 400kV HVDC line with 600MW capacity in operation since 1996.
		The EU-funded project, operational since 2020, links German and Danish offshore wind farms.
Germany- Czech	50Hertz (Germany) CEPS (Czech)	A 380kV AC transmission link (augmented from 220kV) in operational since 1959.
Germany - Poland	50 Hertz (Germany) PSE (Poland)	Two interconnector lines running at 380kV AC. A third is in planning phase.
Germany - Sweden	Baltic Cable AB	260km long, 440kV HVDC line, with a capacity of 600MW.

Note: Baltic Cable AB, 100% owned by Norwegian company Statkraft Asset Holding AS, is designated as an independent Transmission System Operator under the German Energy Industry Act.

Source: 50Hertz



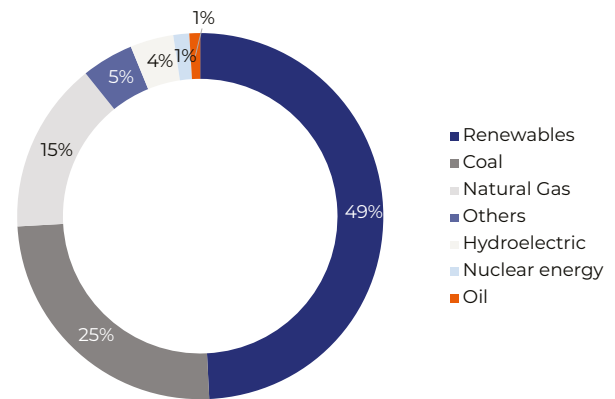
Drivers in Energy Transition

The German power system has been progressively operating with a rising share of renewable energy. With rapid capacity addition in wind and solar power capacities, the country is well placed to exceed its 2030 goals of renewable energy generation. The capacity addition trend signifies the same. The country had an annual average of 6.6GW in renewable capacity addition during 2018-2021. By the end of 2022 and 2023, it was 10GW and 18GW, respectively (IRENA, 2024). The pipeline has grown exponentially. Between 2024 and 2028, over 100GW of renewable power capacity is set to be auctioned (Rystad Energy, 2024). The policy thrust on getting renewables to minimise its reliance on energy imports (especially natural gas) has been a major propelling factor. Since the energy crisis of 2022, which arose from the Russian invasion of Ukraine, there has been a sharp decline in the dependence on gas imports. An even sharper decline is underway for coal.

From the grid operators' perspective, the transition in the power mix is taking place on multiple fronts. One of them is coal-based power – a source of baseload capacity in a grid increasingly needed in balancing intermittent energy supply. In April 2024, 15 coal-fired plants, aggregating 3.1GW, were closed. The policy goal is to retire all of it by the end of the decade (Power Technology, 2024). To be sure, quite a few of the coal-fired plants were reactivated in 2022, as renewables and other sources of the power mix were insufficient to compensate for gas shortages. Since then, the stabilisation in gas supply and price helped ease the pressure on the power system.

Grid stability concerns are making utilities and regulators less favourable to the idea of an aggressive coal exit. The regulator, for instance, has designated some coal-fired plants as

Power Generation Mix



Source: Energy Institute

system-relevant until 2031. Furthermore, the stipulated timelines for keeping coal-based power in the power mix include keeping the last units active until 2038. Separately, the TSOs regard it as a systemic requirement to keep the coal-based power generation capacity as part of the grid's reserve beyond the official date of a full shutdown (Argus, 2024).

An even sharper shift of energy transition took effect with the exit from nuclear power, as of April 15 2023, from the power system. Till then, nuclear power generation was contributing just about 1% (as shown in the accompanying chart) to the generation mix. The policy reasoning for this decision, as a combination of safety, costs, etc., has been subject to criticism, as the grid also lost a critical low-emission and competitive cost baseload energy source. The French experience shows the role of nuclear power generation capacities in enabling a lower emission profile for the power sector while meeting the grid's baseload requirements.



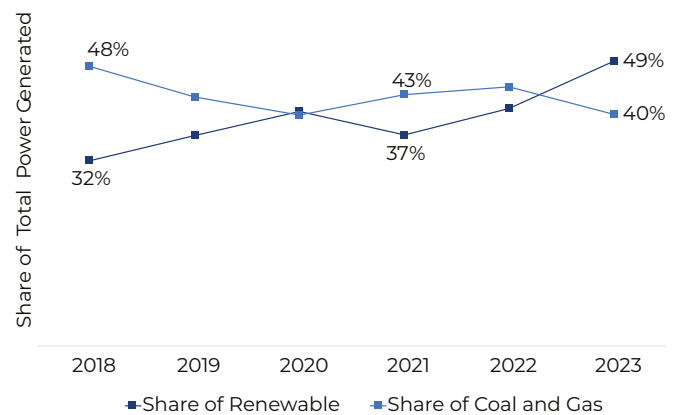
In addition to grid management in a transitory phase, the TSOs must also prepare for the anticipated demand. The German power system faces a rise in demand from new segments such as data centres and electric vehicles and from the rising electrification in industries (Montel, 2024) and residential heating systems. Globally, Frankfurt ranks among the top data centre markets, while other locations, such as Berlin, are rapidly emerging in importance. The German Data Centre Association's Report for 2024 (German Data Center Association, 2024) projected a three-fold rise in the IT power connected to colocation data centres (accounting for 70% of the German data centre IT power load).

Policy and Regulation

The critical need for timely grid expansion is observed in the direct policy/regulatory attention. The Federal Ministry of Economic Affairs and Climate Change (BMWK) has been supervising and leading the vital policy matters related to the grid expansion and its related elements, including approvals, etc. The Grid Expansion and Acceleration Act (NABEG), brought into effect in 2011, guides most of the ongoing measures in the power transmission infrastructure (BMWK, 2024). The regulatory body, Federal Network Agency (Bundesnetzagentur in German), oversees the operation and management of the high-voltage power transmission network and thus also supervises the implementation of the NABEG.

Regulatory oversight for power transmission includes other relevant legislation, such as the Energy Industry Act, Federal Requirement Plan Act, and Power Grid Expansion Act. These norms guide the multi-staged processes related to planning, siting, permitting, public consultation, and approvals for transmission projects. Reform measures are in consideration, through changes in policy guidelines to address the longstanding need to rationalise the approval process. In May

Transition in Grid-Connected Power Generation



Source: Energy Institute

2024, the lawmakers agreed on a set of reform steps for faster approvals in infrastructure projects (Clean Energy Wire, 2024). Recent experience has shown the impact of such measures. In the aftermath of the energy crisis of 2022, liberal permitting for renewable energy projects catalysed a rapid capacity addition.

The spike in renewable energy capacities is well aligned with the decarbonisation goals, but it poses a challenge for the TSOs. The incentives and grid charges constitute an important part of the TSOs' grid expansion strategy since raising the necessary debt and funding depends on their approved returns. The regulations classify the utilities' costs into controllable and uncontrollable categories. The former typically includes digitalisation and other similar measures to lower costs and qualifies for performance-based returns. The latter involves an approved return on equity (RoE) over the base rate through the traditional cost-plus approach. The regulator has recently raised the allowed RoE to 7% for the new projects financed after January 2024 as a partial relief for the grid utilities' stepped-up capital expenditure (BNEF, 2024).



Market Opportunity

The regulatory authority's estimates point to the commissioning of 1,870 km of total line length by the end of 2024. It includes major projects such as the interconnector project SuedLink (Clean Energy Wire, 2024). In March 2024, the agency shared the network development plan drawn for the period till 2045, in line with the goal of a climate-neutral power system (Federal Network Agency (Germany), 2024). The projected plans indicate a steep rise in the capacity base. About 4,800 km of line will be constructed, and another 2,500 km of reinforcing will be done. Importantly, the plan confirms the development of five new HVDC transmission lines, each with a power transfer capacity of 2GW.

Estimated Transmission Grid Spend

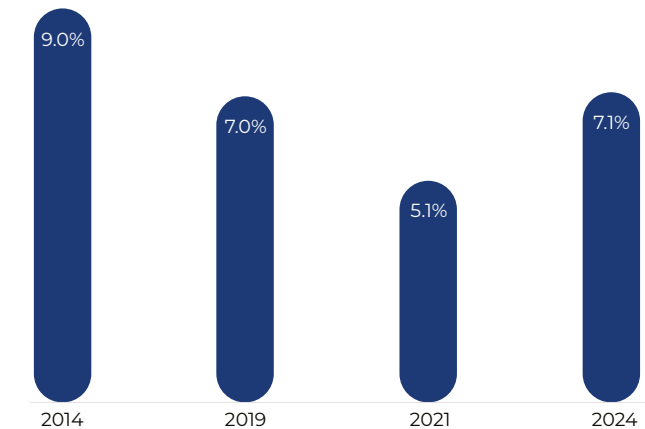
Spend (\$ billion, real 2023)	
2024	13.7
2025	14.2
2026	15.4

Source: BNEF

HVDC transmission projects are vital for the commercial viability of the planned offshore wind power generation. The network development plan shows 35 transmission projects in the North and Baltic Seas to evacuate the 70GW offshore generation capacity targeted in the German Offshore Wind Energy Act. The planned infrastructure could be unprecedented in scale or complexity. Some of the early signs of progress include the equipment/technology tie-ups. As of July 2024, the TSOs formed partnerships with technology providers Hitachi Energy, Siemens Energy and GE Vernova for multi-terminal hubs with direct current circuit breakers. The proposed hubs will enable the links to new HVDC connections (renews.biz, 2024).

The anticipated skew in the wind power projects could worsen the problem of grid congestion. To prepare in this regard, the utilities are actively considering grid-scale energy storage projects to help support the ongoing expansion and renovation. As of June 2024, construction started on a 250MW/250MWh grid booster storage project (termed Netzbooster in German TSOs' parlance). The TSO TransnetBW is implementing it in partnership with battery storage integrator Fluence (Energy Storage News, 2024). The proposed storage capacity is aimed to serve as a storage-as-transmission asset by mirroring the function of a typical transmission connection and, in the process, allowing higher power transfer from the existing lines. Other TSOs, namely TenneT and Amprion are planning similar assets of 250MW and 200MW capacity, respectively.

Allowed Return on Equity by Year of Determination



Source: BNEF



The massive asset expansion and overhaul involve a sharp rise in the capex commitment. As far as plans go, all the TSOs have outlined massive spending over the next 6-10 years. It is an unusual spike that is prompting the TSOs to explore all options. The TSO TenneT (an operator in the Netherlands and Germany) has a projected capex worth €160 billion for 2024-2033, which is difficult to manage in the face of the TSO's credit profile and the regulated asset base. The TSO is thus in the middle of many ongoing measures, such as the disposal of non-core assets and a series of negotiations for the sale of the German power transmission business (the TSO entity being owned by the Government of the Netherlands) (Moody's, 2024). Earlier during the year, TenneT received recapitalisation support from the German government to help bridge capex requirements without impacting its credit ratings.

Outlook

The German power transmission network development plan for 2037/2045 projects 12,700 km of transmission line length (across AC and DC) as a confirmed plan of capacity addition. Another 950 km of transmission line length is from transmission projects that have not been confirmed (as of March 2024). It is likely that even these estimates could be revised upwards to match the rising requirements in grid connectivity and reinforcement (Federal Network Agency, 2024). Considering the progress so far, it imposes a huge requirement in project development and resourcing.

Despite the challenge, project cost and its financing may not be the deciding factors for the TSOs, considering the policy attention in this segment. However, implementation challenges and the resulting delays may drastically impact viability. In this context, there is a considerable risk for the TSOs. An example is the Federal Maritime and Hydrographic Agency's January 2024 notification flagging possible delays

The scale of the announced capex plans is relatively smaller for other TSOs. In May 2024, 50Hertz announced €20.7 billion in capex over the next five years, reflecting a roughly five-fold rise compared to the spending of the past five years (SEI, 2024). Amprion's investment goal is of similar magnitude, at €27.5 billion, though it is subject to a risky credit profile, as indicated in the Fitch Ratings Outlook of April 2024 (Fitch, 2024). All utilities face similar challenges in the financial market, arising from a weaker credit profile. Progressively, the grid fees and the regulated returns are in focus as utilities seek justified incentives for the capacity expansion expected of them. Regulatory authorities have been willing to allow better incentives, as observed in the recent approval for revised grid charges and the regulated returns on equity.

in North Sea wind farm connectivity due to supply chain issues. Amprion and TenneT are responsible for the links related to the concerned notification (Renewables Now, 2024). Lengthy and cumbersome permitting rules put additional barriers to project development.

The measures undertaken to resolve ongoing issues, including those of permitting bottlenecks (e.g. exploring the existing railway track power lines to ease siting issues of new transmission lines), point to the seriousness afforded by the highest authorities. The progress in augmenting the transmission infrastructure will be keenly tracked by all stakeholders in the German energy space. The upcoming investments also present an opportunity to permanently transform the legacy grid into a modern, flexible power system.



SPAIN

Spain has experienced the most rapid growth in renewable energy penetration among European Union countries in recent years. Progressively, conventional energy resources are being phased out, as wind and solar power generation occupy the predominant place in the energy mix. The speed of this shift, however, outpaced the transmission network expansion. The rising instances of curtailment point to the constraints imposed by an inadequate grid capacity. Closing this gap would require time. The rise in investments in the last couple of years is encouraging, but the operator and the policy authorities must do more to meet the requirements ahead.



GDP
(Current Prices, \$ 2023)

1,621 Bn

Projected Average GDP
Growth 2024-28

2.0%

10-Year Govt. Bond Yield
(12-Month Rolling Average)

3.2%

Country
Credit Rating

A

Renewable Energy
Share

41%

Total Transmission Line
Length (Km)

48,633

Note: Renewable Energy Share excludes hydropower



Transmission Network

The Spanish power transmission network, operated by Red Eléctrica de España (REE), is predominantly at 220kV and above voltage levels. Over recent years, the network has stood out in the European Union for its progress in achieving a decarbonised power system. Seamless grid integration is among the key challenges for the TSO, not least because of the increased prevalence of renewable power. The country's geography requires that it have ten different electrical systems. The non-peninsular areas have separate operations because of their size and isolation. (REE, 2024). The peninsular system is connected to France, Portugal, Andorra and Morocco, accounting for over 90% of the total power demand.

The peninsular segment is notable for its cross-border interconnections, which enable cross-border power trade. The Iberian power market, involving integrated Portuguese and Spanish power systems, plays an important role in this regard. The interconnection is gradually being augmented even further for enhanced transactions. Due to the critical role of these projects, several of Red Eléctrica's interconnection projects are also classified as 'projects of interest' in the EU, which helps attract funding and related support.

The onshore transmission infrastructure is expanding to accommodate demand arising from new connection requests, reinforcement of links between the islands, and improving the network's meshing and reliability. By the end of 2023, the operator added 157 km of new lines and 143 new substations (REE, 2024). The capacity growth needs to be much higher to match the rising demand on the grid. Between 2019 and 2023, the total transmission line length registered a CAGR of 0.4%, while the year-on-year growth in 2023 was just about 0.2%. The line length grew by an annual average of 2.1% between 2010 and 2016. There has been a deceleration in the incremental capacities since then (Statista, 2024).

Transmission Line Length

Line Length (circuit km)	
66 kV	3,075
132 kV	3,075
220 kV	20,273
400 kV	22,210
Total	48,633

Source: Red Eléctrica

Cross-border Transmission Linkages

Country Linkage	TSO/ Business Concern	About the Linkage
Spain - France	Inelife (equal share of TSOs REE and RTE)	A 64.5km long link commissioned in 2015 enabling 2,800MW in power transfer capacity. There are four HVDC lines in this interconnection. Another is due by 2027 (IEA, 2022).
Spain - Portugal	REE and REN (Portugal)	The existing link comprises six 400kV and three 220kV lines (ERSE, 2023)
Spain - Morocco	REE and ONEE (Morocco)	Two HVAC 400kV lines with a combined power transfer capacity of 1,400MW (MED, 2022)
Spain - Andorra	REE and FEDA (Andorra)	Existing interconnection is worth about 107MW and is due for reinforcement / expansion (European Parliament, 2023)

Source: Red Eléctrica, ERSE, IEA

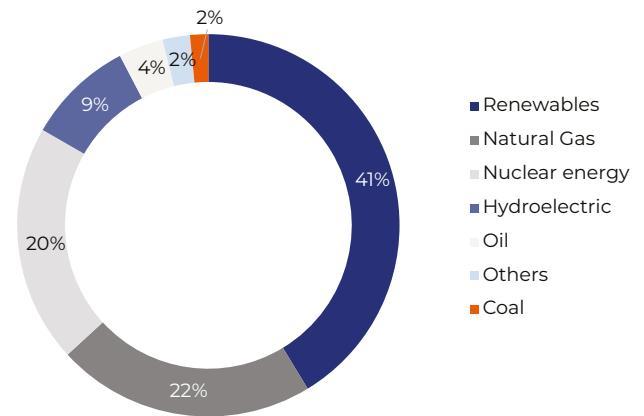


Drivers in Energy Transition

The Spanish power system has been progressively operating with a rising share of renewable energy. Its ambitious renewable energy targets are well complemented by a steady capacity addition rate. Between 2021 and 2023, an annual average of 7.6GW of renewable energy generation capacity came online, which is more than thrice the average capacity added between 2017 and 2020 (IRENA, 2024). With policy and regulatory support, the renewable pipeline has grown manifold in recent years. As of July 2024, the Spanish government had approved the construction of over 28GW worth of renewable power projects. (Reuters, 2024). The country’s rapid progress in renewable energy stands out in the region – Spain was ranked among the top three countries for the rise in renewable energy penetration achieved between 2022 and 2023 (EEA, 2024).

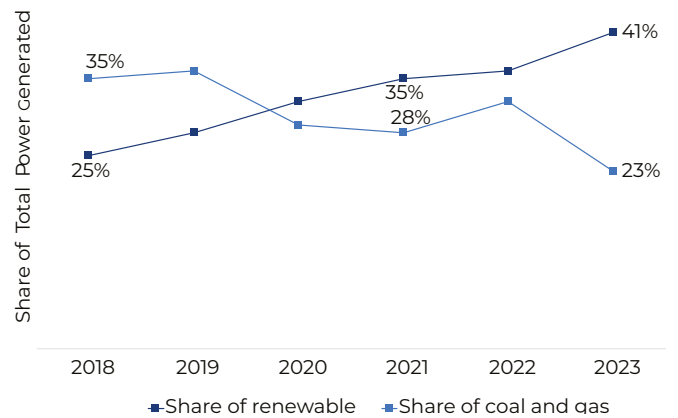
The growth in clean energy resources is progressively outpacing the grid capacity. The rise in grid congestion and curtailment episodes coincides with the accelerated pace of capacity addition in wind and solar energy. Since 2022, congestion management costs and the volume of non-compensated renewable energy curtailment have risen sharply. Between 2017 and 2020, the cost of grid restriction was an annual average of €390 million. In 2022 and 2023, it reached €1.3 billion and €2.1 billion, respectively. Non-compensated curtailment is a more significant concern – in 2022, over 1TWh of renewable energy, amounting to 1.2% of the related generation asset output, was curtailed. Technical restrictions involving grid congestion are generally manageable through measures related to voltage control, reserves, and market operations. Non-compensated curtailed volumes are primarily due to an inadequate grid capacity. (Aurora, 2024).

Power Generation Mix



Source: Energy Institute

Transition in Grid-Connected Power Generation



Source: Energy Institute



An expanding renewable energy base increasingly displaces a significant share of conventional energy resources. Coal is the most discernible one in this regard. Its already insignificant share will decline further as the government actively seeks to allocate replacement capacities instead of coal plant retirements. (Energy Storage News, 2024). The entire process could be completed by 2025 as the speed of the process has been far higher than anticipated earlier. Active policy assistance regarding financial support for the plant operators, labour and other key stakeholders has helped. A much less steep decline is observed in the case of gas-based power, whose relative share stood at 22% in 2023 against 26% in 2020. The advantages of gas-based power units, such as enabling grid flexibility, have helped retain their share in the power system, although they have a diminishing role. According to the country's gas grid operator Enagas, the gas-fired power plants are likely to be in operation beyond 2030 (Montel News, 2024).

The displacement of conventional energy sources extends to nuclear power, where a marked decline is underway. A significant share of nuclear generation is already going offline in the run to a targeted phaseout by 2035 (Reuters, 2023). In March 2024, the nuclear power generation in the grid was reduced to half, partly due to the recurring maintenance issues and in significant part due to the surge in renewable power. The power plant operators held high wind power output as the major reason for placing the units on standby (S&P Global, 2024). Officially, the decommissioning of nuclear power plants is expected to start in 2027, expecting renewable energy and energy storage capacities to compensate for the gap (Balkan Green Energy News, 2023).

The transmission operator is thus likely to face significant pressure from the displacement of conventional energy in the upcoming 5-6 years. Grid flexibility options such as in gas or long-duration battery storage may play an enhanced role. Notably, the large-scale phaseout of conventional energy does not impact the

outlook for electricity demand. BNEF projections show that the country's total electricity demand, modelled in a macroeconomic framework, could register a compound annual growth rate of 0.7% between 2024 and 2035. Instead, the sub-transmission (or the medium-to-low voltage distribution network) could be in focus because the same BNEF projections point to a 23% rise in demand arising from electric vehicles.



Policy and Regulation

The policy and regulatory backdrop for power transmission is centred on the pace of the energy transition and the expansion of the infrastructure to support it. The latest renewable energy targets point to the ambitious scale. As of September 2024, the government approved 76GW of solar and 62GW of wind for commissioning by 2030 to achieve an 80% share of renewable energy in total power generation (PV Magazine, 2024). The Ukraine war and resulting energy crunch added impetus to the renewable energy goals, as regulatory norms were suitably amended to facilitate deployments.

Transmission plan approvals are vital to the grid infrastructure expansion process. In 2022, the government approved a four-year investment plan to augment and strengthen the grid. The plan amounted to about €7 billion in total spending, including sub-transmission networks and the high-voltage transmission network, the latter comprising 2,700 km of new lines and 700 km of new undersea interconnector links. Renewable energy connectivity is the highest priority in this plan, as it supports the national objectives in decarbonisation. (MITECO, 2022).

The government departments have also initiated long-term transmission planning for the 2025-2030 horizon, considering the project pipeline already in progress from the previous planning periods and the new proposals. Also, the planning process, especially the stage involving public hearings, is being modified to make it conducive for strategic projects.

In the meantime, other measures are being taken to streamline the rush for grid connectivity. Recent regulatory amendments stipulate an auction-based allocation approach to bring order to the existing process. This is being gradually brought into implementation. In April 2024, the Ministry for the Ecological Transition and the Demographic Challenge

(MITECO) launched a capacity tender for synchronous generation from renewable and storage-based units. The tender aims to grant transmission access through pre-identified grid nodes at 220kV and 400kV (Enerdata, 2024). More such auctions can be expected as developers expand upon the generation pipeline. Furthermore, the regulations encourage converting existing generation units (especially renewables) into hybrid mode, i.e. generation with storage, without losing the original grid access rights.

A critical regulatory stipulation related to grid investment is presently under review. It refers to a legal cap on the investments of power transmission and distribution network operators. The investment limit for the power transmission network operator is 0.065% of the Gross Domestic Product. Considering the emerging investment requirements, this norm is overdue for revision. In January 2024, a government minister spoke about the ongoing deliberations to raise the limit (Reuters, 2024).



Market Opportunity

REE's parent company, Reidia, has the latest quarterly financial results showing a rise in grid investments. According to the latest financial results, REE's investment during April-September 2024 rose 18% (reaching €603 million) over the previous year's comparable period. Strategically important projects under development include the interconnectors, and the 200MW Chira-Soria pumped hydropower project. (redea, 2024). The TSO's annual investments have almost doubled between 2019 and 2023.

Cross-border interconnector projects are among the critical focus areas in existing investment plans. About 18% of the transmission investment is exempt from the regulatory cap, and this is almost entirely made up of interconnector projects. Such investments are also important because Spain lags behind the EU's target of maintaining interconnection capacity at a 15% share of the total installed generation capacity. Many projects are thus presently in the planning stages and may need a prioritised investment allocation.

The integrated Iberian energy market, comprising Spain and Portugal, may need additional investments to realise the net zero objectives. The existing investment plan, spanning the period of 2021-2026, provides for an outlay worth €7.3 billion. Over 80% of the planned spending is guided by interconnections, renewable power connectivity, and system reinforcements.

Estimated Transmission Grid Spend

Spend (\$ billion, real 2023)	
2024	1.8
2025	1.9
2026	1.9

Source: BNEF

Major Transmission Projects in Pipeline

Project	Particulars	Cost	Planned commissioning
Iberia-Mallorca	A second 2x200MW link between the mainland and the Balearic Islands.	\$1.4 billion	Around 2026
Tenerif-La Gomera	Connecting the Canary Islands through 36 km long undersea cables.	\$0.1 billion	2025
Bay of Biscay (Spain-France)	A 400km long HVDC link to raise existing power transfer capacity.	\$3.24 billion	2028
Aragon-Western Pyrenees and Navarra-Landes	Two new projects between Spain and France presently in the planning and scoping stages	-	-

Source: BNEF



Outlook

The ongoing network investment under implementation refers to the approved plan period of 2021-2026. Fully implementing this plan would entail 2,681 km of new transmission lines and 7,057 km of updated lines with related expansion in other transmission assets (Redeia, 2022). The trend so far points to much lower annual incremental capacity. In the five years to 2023, an average of 192 km of line length was added annually. Thus, the progress in this plan will be a vital input for investors and developers, and the subsequent transmission planning period of 2025-2030, for which studies are underway.

Better incentives are needed to address the issues of timely capacity augmentation. The cap on the grid operator's investment commitment stands out as an oddity compared

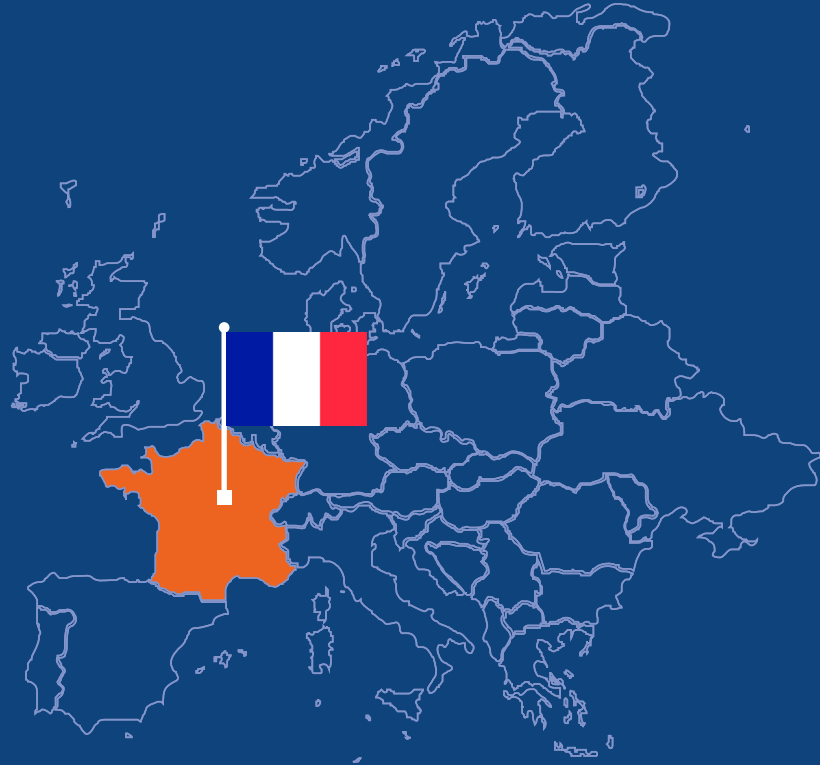
to expectations of large-scale infrastructure expansion. The planned revision of this cap is overdue, and delays are unlikely to help the operator's case. Otherwise, the investment commitments are likely to lag the required levels. For instance, BNEF's Net Zero Scenario projections suggest that Spain's annual average investments in the grid network (transmission and distribution) should be \$6.4 billion from 2024-2030. In practice, the annual planned investment till 2026 is at \$4.7 billion.

Spain's success in energy transition goals is likely to be tested by the timeliness of the grid network availability. The planned capacity addition will also entail a marked shift from the legacy processes followed by the regulator, policymakers and network operator over the years.



FRANCE

The French power system has a leadership position in being among the most decarbonised systems globally despite operating with a renewable energy penetration of around 16%. Nuclear energy has been a major supportive base in its generation portfolio. It has helped the transmission operator run the system with minimal disruptions as renewable energy capacities grew. However, the systemic constraints are on a different front. The extensive network, also among the largest in the region, faces ageing and requires renovation or replacement. The expansion of renewable energy capacities, especially those in offshore wind power, and the need for cross-border interconnection capacity are driving a spike in spending commitments far beyond the traditional range.



GDP
(Current Prices, \$ 2023)

3,053 Bn

Projected Average GDP
Growth 2024-28

1.3%

10-Year Govt. Bond Yield
(12-Month Rolling Average)

2.9%

Country
Credit Rating

AA-

Renewable Energy
Share

16%

Total Transmission Line
Length (Km)

105,796

Note: Renewable Energy Share excludes hydropower



Transmission Network

RTE is the sole French power transmission system operator, managing a network with voltage levels ranging from 63kV to 400kV. The high-voltage bulk power transmission is predominantly carried out at 225kV and 400kV. RTE's network is among the most extensive in the European region and also involves sub-transmission networks at lower voltage levels. A majority share of the network is based on overhead transmission lines, though the share of underground lines has been rising.

As of 2023, the ten-year growth in total line length stood at 0.1%, indicating a negligible expansion (RTE, 2024). Strikingly, the recent trend in transmission line length is notable on one major count: It is declining. This is primarily because of the decommissioning of lines reaching the end of commercial life. Other reasons include shifting overhead lines to underground based on local network requirements. The age of the assets is a major factor that appears to outweigh expansion among strategic priorities.

The average age of the transmission network, per RTE's ten-year network development plan of 2019, stood at 50 years (RTE, 2019). According to RTE, the age of network assets is much older than anywhere else in the European region. Furthermore, after 2030, many of the transmission lines will reach 85 years of age and will be beyond reinforcement and life extension works. Timely replacement of the capacity will be critical not only for service reliability but also to meet grid connectivity demand from upcoming renewable power generation projects.

Transmission Line Length

	Underground (km)	Overhead (km)	Total (km)
2018	6,202	99,655	105,857
2019	6,415	99,527	105,942
2020	6,665	99,382	106,047
2021	6,823	99,147	105,970
2022	7,055	98,762	105,817
2023	7,349	98,447	105,796

Source: RTE

A key segment of the transmission network is cross-border power exchange. The power system has about 50 interconnectors with six European countries and operates with varying power allocation methodologies for export and import transactions. Renewable energy, especially offshore wind, has been a major driver in the interconnection projects. Furthermore, there is an EU requirement of 15% interconnection capacity, making it imperative for the utility to expand the cross-border power links.



Cross-border Transmission Linkages

Country Linkage	TSO	About the Linkage
France-Italy	RTE and Terna	190 km long double underground line with 600MW capacity each, operational in 2023.
France - UK	RTE and National Grid	The first link was operationalised in 1986, with two more links added since then.
France-Spain	RTE and REE	The EU and EIB funded project, operational since 2015, with a capacity of 2GW.
France-Germany	RTE (France) TransnetBW (Germany) Amprion (Germany)	Five electricity interconnectors in operation with a total capacity of 3.0GW, construction of two additional interconnectors is under planning with total capacity expected to go up to 3.3GW by 2025.
France-Belgium	RTE (France) Elia (Belgium)	Two interconnectors with the first one being commissioned in 1974 with 380kV AC lines, total transmission capacity has been upgraded to 6.0GW from 3.0GW by installing high temperature, low sag (HTLS) conductors.
France-Switzerland	RTE (France) Swissgrid (Switzerland)	Interconnected since 1958 with 220kV level, new 380kV lines have been constructed to replace the 220 kV line, with current power transmission capacity of 3.7GW.

Source: CRE, RTE, Terna, ElecLink, EIB, Offshore Energy

Drivers in Energy Transition

In the European region, France lags in the rate of renewable power capacity addition. Between 2018 and 2023, renewable power generation capacity grew at a compounded annual growth rate (CAGR) of 6.5%. An enhanced rate of capacity addition is needed to align with the European Union's target of 42.5% as the share of renewables in the energy mix (Energy News, 2024). Steps are being taken to address this. The National Energy and Climate Plan (NECP) submitted to the European Commission in July 2024 refers to a 41.3% share of renewables in final energy consumption by 2030. NECP's targets correspond to 54-60GW of solar, 33-35GW of onshore wind, and 3.6GW of offshore wind capacity, besides additional nuclear power generation. These targets mean a significant jump in the renewable capacity pipeline, some of which is already visible in the government announcements of auctions (Enerdata, 2024).

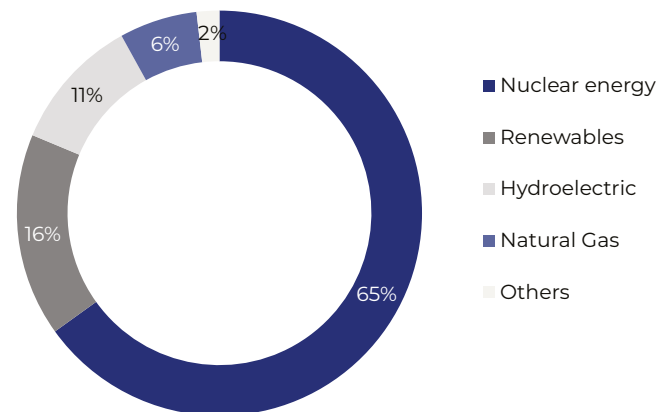
Nuclear power generation is highly emphasised in policy, especially because of its decarbonising impact on the energy mix. For the transmission operator, nuclear energy also helps as a stabilising resource against intermittent renewable energy in the grid. Furthermore, its highly competitive cost has helped the power system become a net exporter in cross-border power market transactions. In June 2024, the government announced approval for eight nuclear power reactors for commissioning in 2035 onwards (Energy News, 2024). Availability of the capacities could be subject to uncertainties in costs and implementation, considering the experience so far (FT, 2024). Yet, nuclear power acts as a key hedge for the power system to balance the needs of a clean yet stable energy supply.



The dominance of nuclear power is also the reason why the role of coal-based power is at a negligible level (0.3% of generation in 2023). Gas has a relatively higher contribution. However, excluding the year 2022 as an outlier (supply crunch arising from the Ukraine war), the average share of gas-based power generation between 2018 and 2023 has been 6.5%. Any further reduction in the share of gas would require sufficient capacities in baseload generation (such as nuclear) to enable smooth grid management.

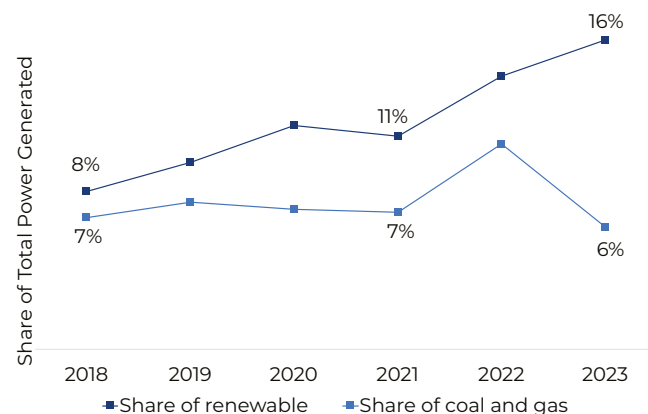
Notably, the demand for gas-based power generation was significantly low during 2024, adding to the year's total power export. Better hydropower reservoirs, an active nuclear power fleet (offline earlier for maintenance) and high availability of gas-based power together made the French power export reach the maximum level during 2024. To this, there was the added vital factor of low or subdued demand. The estimated power demand of 450TWh in 2024 is equivalent to that of 2023 and less than the pre-pandemic average (Reuters, 2024). The emerging sectors of electric mobility and data centres are expected to raise the demand. Electric vehicles may mostly operate at sub-transmission or lower voltage levels of RTE's network.

Power Generation Mix



Source: Energy Institute

Transition in Grid-Connected Power Generation



Source: Energy Institute



Policy and Regulation

The NECP highlights a significant increase in electricity demand from the industrial sector as it shifts away from fossil fuels, regardless of the technology used (such as hydrogen, carbon capture, or electrification). This will require adjustments to the electricity transmission and distribution networks, especially in areas with high concentrations of energy-intensive industries. To accommodate this, under the Renewable Energy Acceleration Law, connection times for energy projects will be shortened. However, in congested areas and while the necessary grid infrastructure is being developed, priority may be given to certain projects for connection to the grid based on their ability to reduce emissions or level of maturity. This shift is expected to add further strain on the grid's flexibility, already challenged by the increasing share of intermittent renewable energy sources (European Commission, 2024).

The tariff framework is of major significance for RTE. Tariffs are set every four years under the Public Transmission User Tariff (TURPE) and adjusted annually based on inflation, a cost factor (0.49%), and a clearance coefficient to balance the Income and Expenditure Regulation Account. Presently, TURPE-6 is in effect, spanning the period August 2021- July 2025. Tariff values are revised annually within this framework. In this regard, it is notable that the regulator postponed the application of a tariff rise, originally planned to take effect in August 2024, to February 2025. This was done to monitor the fluctuations in energy costs that would impact the households and other end consumers (Energy News, 2024).

Among other important parameters, the regulator approves RTE's regulated rate of return based on the weighted average cost of capital (WACC). For the current regulatory period, the WACC is set at 4.6% (RTE, 2024). This is lower than the 6.125% approved in the previous regulatory period. The next tariff-setting period will be important for the utility in determining its financial preparedness for planned investments and business growth.



Market Opportunity

RTE has proposed an investment of €100 billion between 2024-2040. The proposed investment is likely manageable due to the favourable credit rating and regulated asset base of the RTE. In April 2024, RTE successfully issued two tranches of €500.0 million bonds, reflecting market confidence in RTE's creditworthiness, further validated by Standard & Poor's renewal of RTE's long-term "A" rating with a stable outlook (RTE, 2024) (RTE, 2024). Notably, the proposed investment of €100 billion stands in stark contrast to the €39 billion originally budgeted in the transmission planning period of 2021-2035.

Estimated Transmission Grid Spend

	Spend (\$ billion, real 2023)
2024	2.5
2025	3.1
2026	3.7

Source: BNEF

The planned investment outlay, indicating the scale of grid capex, is a significant increase over the recent past - €1.2 billion in 2019, which rose to €1.7 billion in 2023 (RTE, 2024). There is also a marked shift in the planned investment towards new or expansion projects, against the predominance of renovation or system strengthening ones earlier. Modernisation, digitalisation and asset renewals made up about 40% of the investments in recent years. The upcoming investment period will likely be driven by major expansion projects, including interconnectors and offshore wind power project connections.

There is a commitment to double the power interconnection capacity by 2035 (from 15GW to 30GW). Such a milestone will align the country's power transfer capacity with the European Union's stipulated 15% interconnection capacity as a share of total generation capacity. Presently, the country is marginally above the 11% level.

The interconnection with Spain, presently under development, could be one of the key links to expand its cross-border power exchange capacity by 2030, besides opening up a new power market with Ireland.

Anticipating the emerging material requirements, the grid operator has begun finalising the critical deals. In November 2024, RTE announced a significant €1 billion deal with multiple European fibre-optic cable manufacturers for about 5,200 km of high-voltage underground power cables. The deal requirements include exclusive manufacturing within Europe, with about a third of it within France. The investment of €668.0 million in domestic production will utilize almost all of France's remaining cable manufacturing capacity until 2028 (Reuters, 2024) (RTE, 2024).



Outlook

RTE's ten-year network development plan projects 5,000 km of new transmission lines to meet the energy transition roadmap outlined in the policy objectives. A major thrust is on the interregional power transmission, aiming to double the capacity by 2035. HVDC transmission systems are likely to be preferred for the upcoming interconnectors, especially those involving submarine links. Ageing of the transmission network may, however, occupy a bigger share of the planned investments. RTE's observations in the transmission plan filings placed this in context. The historical asset renewal spending outlay, at an annual average of €400 million, needs to be €650 million by 2035 and roughly double thereafter (Ember, 2024).

The network planning scenarios must incorporate the possibilities of extreme weather events, as was seen in 2024. Shifting overhead lines underground in recent years may be one way to ensure resilience, but this will also entail additional costs. Also, a rapid grid strengthening process may not be very feasible, considering the sheer scale of aged assets in the transmission network. In the short term, the absence of a renovated network will make it increasingly susceptible to weather events.

Timely network availability is also essential for cross-border power exchange. The construction work on the Bay of Biscay link (France-Spain), for instance, was paused due to a court ruling. While RTE has confirmed a commissioning schedule by 2028, a possible delay in this project could depress the Iberian market prices (due to the Spanish renewable energy supply) (Montel, 2024). Several other planned interconnector lines must be commissioned in time to fulfil the government's offshore wind power targets. The cross-border links have been instrumental in French power exports to the larger European power market so far.

With the pace of grid expansion and reinforcement projects rising, power transmission tariffs need to be revised. The government's intervention in this context, as observed in its recent suspension of a planned tariff revision, does not send the right signals (Energy News, 2024). It remains to be seen how the regulator will budget for the planned step-up in transmission and distribution capacities. Meanwhile, the transmission operator must strive to meet the targeted capacity by the end of 2035.



NETHERLANDS

In recent years, the Netherlands' power system registered among the highest renewable power generation capacity growth worldwide. The capacity addition is likely to be sustained, implying high pressure on the grid operator to meet connection requests on time. Additional demand from new sectors like Data Centres makes this phase increasingly challenging for the grid operator. Some of the recent concrete policy steps with the government indicated the importance being attached to resolve this issue. Expansion of the Dutch transmission system is also vital for the European region's ambitious goals of tapping into the North Sea offshore wind power potential, by means of an energy hub. The progress in the network growth is, therefore, a lot more crucial than before.



GDP
(Current Prices, \$ 2023)

1,155 Bn

Projected Average GDP
Growth 2024-28

1.5%

10-Year Govt. Bond Yield
(12-Month Rolling Average)

2.6%

Country
Credit Rating

AAA

Renewable Energy
Share

47%

Total Transmission Line
Length (Km)

14,518

Note: Renewable Energy Share excludes hydropower



Transmission Network

The Dutch high-voltage power transmission network operates at 220kV and 380kV voltage levels with a total line length of 14,518 circuit km (as of end-2023)(Power Technology, 2024). The grid operator, TenneT, is the sole entity for managing the power system. TenneT is also one of the four transmission system operators in the German power system. This might change in the near future, as discussions to divest the German operations have been going on for quite a while. TenneT's Dutch business, the focus of the present discussion, is increasingly driven by the need for rapid network expansion, in addition to the incremental reinforcement requirements.

Renewable energy, and especially offshore wind energy, plays a central role in the region's energy transition framework, as laid out in the European Commission's long-term goals. For TenneT, this means getting the infrastructure ready for wind power projects in the North Sea. The interconnector lines are vital in this context. Its existing link with the UK, for instance, will be bolstered with the ongoing work on the LionLink hybrid interconnector planned for 2030. In the onshore grid segment, the expansion works are largely about augmenting capacities to meet the surge in grid connection requests. For the last 3-4 years, TenneT has been struggling to manage the spike in demand for new connections.

Grid reinforcement is being prioritised as a strategy to enhance capacities with relatively lower lead times. It is replacing 220 kV lines with 380 kV lines where possible. For example, in 2023, it completed a 40 km upgrade of the electricity highway between Eemshaven and Vierverlaten, boosting transport capacity. Additionally, TenneT is implementing the 'Better Use of Existing 380 kV Programme' ('Beter Benutten'), which enhances the capacity of the current 380 kV transmission network by replacing old conductors with new ones and thus avoiding the time-consuming process of building new lines and alleviating congestion more efficiently (TenneT, 2024).

Notably, to address local community and household concerns, the underground transmission lines are being prioritised. This refers to TenneT's network that operates at 50kV, 110kV and 150kV voltage levels. There is a government scheme to relocate such overhead lines in the populous areas, but with a rider that the local municipal authorities bear 15%-20% of the cost. This policy also states that if a new overhead high-voltage line is built, an existing line must be put underground to ensure the total length of overhead lines doesn't increase (TenneT, 2022).

Cross-border Transmission Linkages

Country Linkage	TSO	About the Linkage
Netherlands-Denmark	TenneT and Energinet (Denmark)	Known as COBRACable, with €600.0 million investment, 325 km long, 320kV HVDC line with 700.0MW capacity, commissioned in 2019.
Netherlands-UK	TenneT and National Grid (UK)	Known as BritNed, with €600.0 million investment, 260 km long HVDC line with 1.0GW capacity, operational in 2011.
Netherlands-Norway	TenneT and Statnett (Norway)	Known as NorNed, with €600.0 million investment, 580 km long HVDC line with 700.0MW capacity, operational in 2008.

Source: TenneT

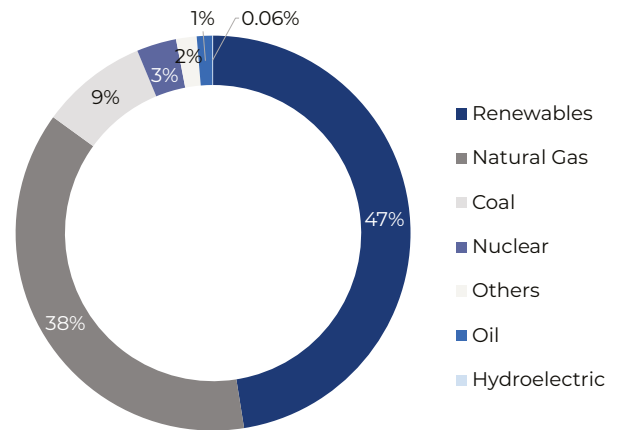


Drivers in Energy Transition

Of late, the Dutch power market had an exceptionally high capacity addition in its renewable power generation resources. Between 2018 and 2023, the installed renewable power capacity grew at a compound annual growth rate of 29% (IRENA, 2024). In 2023, about half of the EU’s new offshore wind power capacity was from the Netherlands’ capacity addition (EV Wind, 2024). The policy target of 70% sustainable power generation by 2030 (Netherlands Enterprise Agency, 2024) is primarily based on the offshore wind power potential. The project pipeline is thus rapidly expanding – in June 2024, the government awarded 4GW of offshore wind project contracts, and another 4GW tender is due in mid-2025 (S&P Global, 2024).

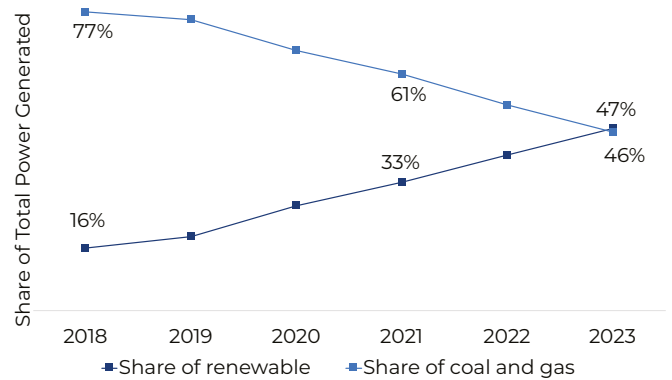
The outsized growth in demand for renewable power connectivity has stretched the grid limits. Tennet’s connection waiting list has risen exponentially. As of October 2024, the Dutch grid had 3.5GW of renewable power capacity in the queue, waiting for a connection (DCD, 2024). Total grid connection requests reached 19,000 in 2024, as compared to 7,000 in 2022. As a result, about nine out of ten provinces face some kind of restriction or suspension in new grid connections. Capacity expansion, the only way to address this, lies in the long-term i.e. around 2030, when the existing projects under development may partially close the gap (Aurora, 2024). The intervening period is likely to be subject to continued constraints. Grid management in such circumstances is likely to be more challenging, with conventional power generation resources rapidly taking a backseat.

Power Generation Mix



Source: Energy Institute

Transition in Grid-Connected Power Generation



Source: Energy Institute



The government has a legislated target of 2029 for phasing out coal-based power generation. This is despite the short-term measures of 2022 allowing an extension of some power plants (ABN Amro, 2024). The binding target helps add credibility to the policy goal of a carbon-neutral power sector by 2035. Unlike coal, gas-based power has a different premise. While the trend shows a gradual decline in the contribution, from 50% in 2018 to 37% in 2023, gas-fired power plants are important in the grid as a flexible generation resource. Grid-scale energy storage can potentially fill this gap but is constrained by technological limitations of short duration (2-4 hours). All the same, the direction of transition over the years makes it abundantly clear that renewable energy penetration is poised to displace fossil-based generation resources.

Policy and Regulation

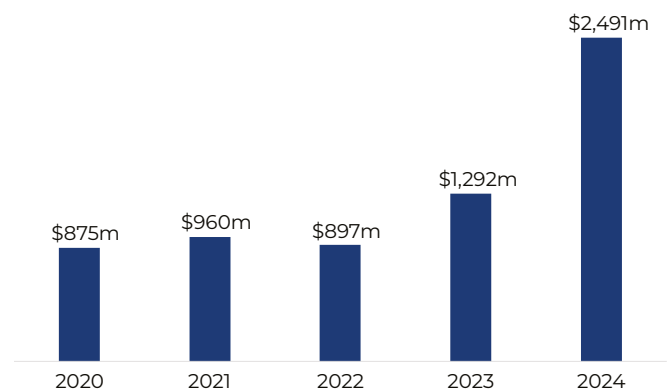
Being state-owned, TenneT's business has a fair share of government involvement regarding the grid's growth and its related key issues. The grid's role in the energy transition objectives makes such involvement essential. One example is the Grid Congestion Action Plan, wherein grid operators (in transmission and distribution segments) work with the government to resolve the pressing issues of grid congestion and connection request queues. This includes measures such as faster approvals, speedy construction where feasible, better utilisation of existing infrastructure assets and engaging external parties to make some facilities (e.g. battery storage) available to others (TenneT, 2024).

Other areas of key policy support include TenneT's grid capex and its financial wherewithal. The Dutch government, as a policy measure, has extended financial support for TenneT's investment commitments. In June 2023, the government provided €1.6 billion for TenneT's Dutch

The Dutch power system is also facing a spike in demand. At the sub-transmission or distribution level, the emerging demand sector is for electric mobility. The rise in electric vehicle penetration and the emergence of large-scale battery manufacturing units to cater to vehicular requirements have added to the overall power demand. At higher voltage levels, the data centres constitute the most important segment for the grid operator. Amsterdam is a data centre hub in Europe. The Dutch Data Center Association projects the country's IT capacity to grow at a CAGR of 9.7% from 2024 to 2029. This growth will increase the total data centre capacity from 863.0MW in 2024 to 1.4GW by 2029, nearly doubling in just five years (Dutch Data Center Association, 2024).

operations. In 2024, it provided a bridge loan facility of €25 billion, securing TenneT's planned investments for 2024 and 2025 (TenneT, 2024). The funding assumes significance as TenneT struggles to find a buyer for its German power transmission business.

Total Allowed Revenues for Dutch Grid Operations



Source: Aurora Energy



Growth in the grid fees helps sustain the operator's finances. The grid offtakers (distribution system operators) pay for the power transmission, construction and maintenance, and grid balancing services. Since 2022, grid fees have been rising in the Netherlands. Between 2022 and 2024, TenneT's allowed revenues for the Dutch power system increased by three times. The rise in energy prices is the main reason (Aurora, 2024). The other key factor is the cost of offshore grid development, which is likely to exert upward pressure on the grid fees in the upcoming periods. Compared to its

neighbouring countries, the Dutch grid fees are significantly higher. Alternative measures may be needed to ease the burden on the offtakers.

There are changes underway in the transmission tariff methodology to be brought into effect from 2025 for greater flexibility. Customers connected to the EHV grid will see an 8% reduction in costs, while those on the HV grid will experience a modest 0.4% increase. This shift is primarily due to the decline in electricity prices in 2023 (TenneT, 2024).

Market Opportunity

By the end of 2023, the grid operator's total investment in the Dutch network reached €2.9 billion – almost three times its level in 2018 (TenneT, 2024). The momentum of expansion and reinforcement projects is likely to be sustained. TenneT's investment plans for the Dutch grid involve about 700 projects (TenneT, 2024) covering five 380kV lines and modernisation of 140 high-voltage substations.

The long-term investment plan for the period 2024-2033 was circulated in April 2024 as part of the regulatory review process. Separate plans have been drawn for onshore and offshore, as the latter involves different regulations (TenneT, 2024). The operator anticipates €60 billion of investment and about 400km of new lines in the Dutch high-voltage transmission system by 2034 (Reuters, 2024). A final confirmation from the regulator would lend credence to the investment estimates. In the meantime, preparatory work is picking up. In August 2024, TenneT signed four-year deals worth €2.5 billion with civil construction companies to expand its overhead transmission lines in the Netherlands.

Some of the vital expansion projects are in the offshore grid segment. One ongoing project is the 2GW Nederwiek-2 offshore HVDC transmission system for commissioning by 2031.

In June 2024, TenneT awarded €2 billion worth of construction and development contracts to the developers Seatrium and GE Vernova for the Nederwiek project (NS Energy, 2024). The latest contracts are in addition to the €3.8 billion worth of contracts earlier with NKT and Prysmian Group for cable connections involving Dutch offshore wind farms (NS Energy, 2023). TenneT is targeting an offshore transmission capacity of 40GW by 2030 to connect the Dutch and German North Sea wind power projects as part of the larger commitments by European countries to develop the North Sea wind power hub (PwC, 2023).

The planned LionLink interconnector project to link UK and Dutch grids contributes to the goal of an integrated North Sea grid. This project is also regarded as a multipurpose interconnector as it will connect the two power systems via a Dutch 2GW offshore wind farm, besides operating as a conventional interconnector for power trade. The project is scheduled for commissioning by 2030 (TenneT, 2024).

TenneT's ongoing phase of accelerated investments is also marked by its adoption of technologies to enhance efficiency. Specific technology solutions are being deployed for better power transfer capacities. As of July 2024,



the utility was using Dynamic Line Rating at its 380kV and 110kV-150kV connections, which enables up to 30% more transmission capacity within the existing infrastructure base. It is being rolled out on a rising number of connections to mitigate waiting times without jeopardising reliability levels (DCD, 2024). To manage emissions in project construction, TenneT has used hydrogen-based drilling systems and electrically driven rigs for tunnel systems.

TenneT's Dutch investment project portfolio will steadily expand as projects marked in the planning stages gradually reach financial closures. With pressure on timeliness, more initiatives in technology and processes are likely.

Outlook

TenneT plans to construct 2,500 km of new grid connections in the Netherlands by 2045, both on land and at sea (TenneT, 2024). The operator's long-term goals are aligned with the policy objectives in decarbonisation. It is, however, the short to medium-term horizon which attracts attention. The country's exponential rise in the renewable power project pipeline has outstripped grid capacity growth in several pockets of the network. Added pressure also comes from the need to strengthen the existing grid assets rapidly.

With rising grid demands, grid expansion project delays may have bigger ramifications than in the past. TenneT's observations, placed in the transmission planning documents of 2024, show that out of the 252 grid projects already in planning stages, 60 were delayed due to both internal and external factors. The grid connection requests, meanwhile, continue to pile up. TenneT's half-year report of 2024 outlined this challenge – pending connection requests rose from about 45 in 2019 to over 700 in the Netherlands by July 2024. Among other factors, the company must circumvent material and resource constraints, including skilled personnel, construction inputs, or dependencies between projects, which collectively impact the scope and execution (TenneT, 2024).



ITALY

The policy push for renewable energy projects has led to a capacity addition beyond the manageable capacity levels of its transmission network. The grid operator is responding to this requirement with a significant ramp-up in capital expenditure for network expansion and reinforcement. The short-term challenge of network congestion and curtailment may still persist. All the same, the country's long-term transmission outlook involves major projects such as those to link the northern and southern regions critical for the concentrated renewable power projects and the cross-border interconnector lines that strengthen Italy's role in the regional energy cooperation goals.



GDP
(Current Prices, \$ 2023)

2,302 Bn

Projected Average GDP
Growth 2024-28

0.7%

10-Year Govt. Bond Yield
(12-Month Rolling Average)

3.8%

Country
Credit Rating

BBB

Renewable Energy
Share

28%

Total Transmission Line
Length (Km)

75,140

Note: Renewable Energy Share excludes hydropower



Transmission Network

The Italian power system has a sole transmission operator, Terna, managing an extensive network across voltage levels of 150 kV, 220 kV, and 380 kV. Terna's extensive infrastructure is organised and maintained through six key transmission departments (North-West, North, North-East, Centre-North, Centre, South) and two transmission districts (Sicily, Sardinia). There is over 30GW of power exchange capacity between the various power market zones. A rapid change in the power system profile due to renewable energy integration and the overall demand is making network expansion an important area of focus.

The long-term trend in the Italian transmission capacity points to a near-stagnant position. Between 2018 and 2023, the total transmission line length grew at a compound annual growth rate (CAGR) of just 0.2%. The emphasis on grid expansion is not yet reflected in the trend. By the end of 2023, about 230 km of line length was added, which is similar to the increment achieved in 2019. With delayed capacity addition, the requirements may just keep mounting. There is, for instance, a rising need to connect the northern and southern regions through

Transmission Line Length

Line Length (circuit km)	
2020	74,723
2021	74,855
2022	74,910
2023	75,140

Source: Terna

long-distance transmission links – most of the renewable power project pipeline is concentrated in the southern region, whereas the demand load is in the northern part.

Cross-border trade is a key segment of the network. Presently, the power exchange involves about 30 interconnector lines with seven countries (Terna, 2024). Several of the existing links are in stages of capacity augmentation as Italy must comply with EU guidelines of maintaining interconnection capacity at 15% of the total generation capacity. Some of the country's interconnector links are also valuable in the goals of an integrated European energy market. An example in point is the planned link with Tunisia (Terna, 2024) which can position Italy as an energy hub of the Mediterranean.

Cross-border Transmission Linkages

Country Linkage	TSO	About the Linkage
Austria	APG and Terna	A power transfer capacity of 300MW enabled by recent commissioning of a new 220kV line
Slovenia	ELES and Terna	Multiple interconnectors operational, bringing total power transfer capacity to about 1,000MW
Greece	IPTO and Terna	A 400kV HVDC link of over 300km length and 500MW in capacity, operational since 2001
Montenegro	CGES and Terna	A 600MW HVDC link operational since 2019. It is planned for augmentation to 1,200MW
Malta	Enemalta and Terna	A 95km long undersea cable with power exchange capacity of 200MW. A second link is in the works

Source: TenneT

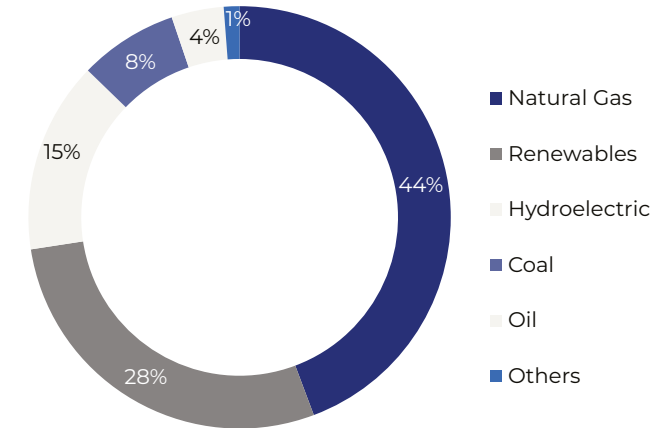


Drivers in Energy Transition

Italy's target of carbon neutrality by 2050 has determined the specific milestones for transitioning the country's power generation mix. In 2023, the government set a new target for renewable energy. By 2030, the utilities must ensure that 65% of the total power supply is from renewable resources (Seneca ESG, 2023). The target was 55% earlier. The emphasis on fast-tracking the transition can be related to the policy stress on reducing fossil fuel dependence in the aftermath of the energy crisis of 2022 (due to the Ukraine war). At that time, several approvals for renewable power projects were rationalised to enable faster commissioning. The results of such efforts are gradually materialising in terms of a vastly expanded project pipeline.

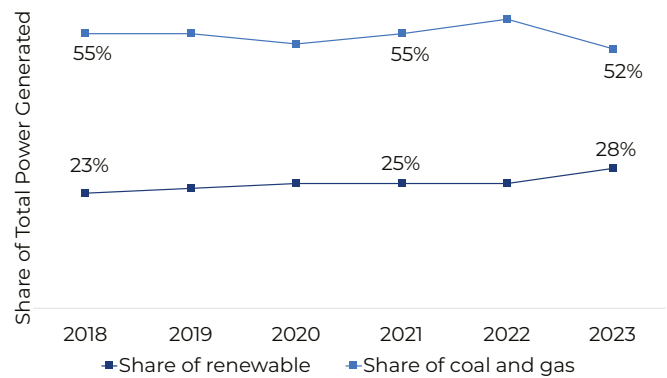
By the end of 2023, over 5.6GW worth of renewable power capacity was added to the grid (IRENA, 2024). This is almost four times the average capacity addition in the previous four years (2018-2022). But the fast clip of renewable power generation is increasingly at risk of facing a grid capacity bottleneck. As of March 2024, Terna had 5,678 grid connection requests worth 337GW of generation capacity (PV Magazine, 2024). Most of them were solar power projects. Offshore wind power requests have risen threefold since 2021 (Investing, 2024). Such accumulation of grid connection requests is indicative of the capacity constraint vis-à-vis generation projects. Even with some upcoming projects not going ahead, the total capacity in queue for grid connection is beyond the requirement for the 2030 targets (Terna, 2024). Grid curtailments are likely to rise as a direct result of the capacity bottleneck and its congestion. The latest evidence in this regard is as of 2022, when 300GWh of wind power, amounting to 1.5% of the total wind-based generation, was curtailed due to limited transmission capacity (Montel, 2024).

Power Generation Mix



Source: Energy Institute

Transition in Grid-Connected Power Generation



Source: Energy Institute



A significant source of grid support has been hydropower generation, which has risen in recent years due to better rainfall and resulting reservoir capacity. However, its uncertain contribution, as observed during the drought of 2022, has been a dampener. Instead, pumped hydropower storage plants may play a bigger role. In 2023, about 100MW of pumped hydropower capacity was added after several years of stagnancy in this segment (IRENA, 2024). The grid operator has been separately engaged in the grid-scale storage capacity auction process to secure flexible generation resources.

Policy and Regulation

The Italian Regulatory Authority for Energy, Networks, and Environment (ARERA) oversees the electricity sector, including key aspects such as tariff regulation, access and connection to the transmission network, and the establishment of quality standards. In recent years, the regulator initiated notable measures towards grid management and development.

In 2017, ARERA established a regulatory framework to support pilot projects focused on enhancing system flexibility. Subsequently, in 2019, Terna launched multiple initiatives to test and integrate demand-side management, variable and distributed renewable generation, and electricity storage systems into the ancillary services market. These initiatives facilitated the addition of approximately 1.5GW of new resources, contributing to enhanced competition and improved system reliability. Since 2022, demand-side management, electricity storage, and distributed generation plants have been authorized to provide secondary frequency and power regulation services, fostering greater competition in this segment of the market (IEA, 2023).

The need for grid-supportive, flexible resources also drives gas-based power in the system. Other reasons include resource availability and the strong gas infrastructure. Also, with the phaseout of coal-based power (expected within 2025), gas presents a better replacement option in terms of emission profile. The continued role of gas-based power may limit the scope of renewable energy. The recent approvals for four new gas-based power plants worth 3.4GW suggest that the reliance on natural gas may not subside significantly in the near to medium-term (Reuters, 2024).

Legislative Decree 199/2021 was enacted in 2021 to advance renewable energy adoption and support Italy's decarbonization goals. The decree aims to streamline administrative processes related to renewable energy production and utilization, while also introducing or revising incentive schemes for renewable electricity, thermal energy, self-consumption, energy communities, and biogas and biomethane production. However, the full implementation of the RED II Decree depended on the central government finalizing several key regulations by mid-June 2022, followed by additional regulations at the regional level.

Italy recently secured approval to move forward with its energy storage capacity auction, known as MACSE, scheduled for the first half of 2025. This initiative aligns with the objectives outlined in the National Energy and Climate Plan (NECP). The MACSE auction will offer 15-year contracts to energy storage projects, providing annual premiums to cover operational costs in return for making their capacity available on the Dispatching Services Market. Overseen by Terna, the auction's primary advantage lies in its provision of long-term guaranteed revenues, which are expected to attract financial backing from banks for project development (Energy Storage News, 2024).



Market Opportunity

Terna has announced its 2024-2028 Industrial Plan, detailing a planned capital expenditure of €16.5 billion over the next five years aimed at reinforcing and expanding the transmission grid as well as enhancing cross-border interconnection capacity. The investment represents a 60% increase compared to the previous plan. It includes major projects such as the Tyrrhenian Link (a submarine cable that will connect Sicily with Campania and Sardinia), the Adriatic Link (a connection between the regions of Abruzzo and Marche that received approval from the Italian Ministry of Environment and Energy Security in February 2024), the Sa.Co.I.3 interconnection between Sardinia, Corsica and the Italian mainland, the 380kV Chiaramonte-Gulfi-Ciminna power line in Sicily, and the Elmed interconnection between Italy and Tunisia (Smart Energy International, 2024).

The Industrial Plan is built upon the principle of the twin transition, emphasizing a strategic approach that integrates simultaneous advancements in energy transition and digital transformation. Terna has established key partnerships to accelerate its projects. Notably, in May 2024, Terna partnered with Hitachi Energy to upgrade existing transmission infrastructure through HVDC technology for the Sa.Co.I.3 interconnection project. This advanced technology is anticipated to boost transmission capacity to 400 MW (Hitachi Energy, 2024). Terna also recently partnered with Alstom in November 2024 for the supply of unified terminal blocks for the modernization of high-voltage power lines. The agreement spans 24 months, with the potential for an additional 24-month extension (Alstom, 2024). Furthermore, in March 2023, Terna unveiled an €11 billion investment in its Hypergrid network, leveraging HVDC transmission system technologies to advance energy transition and ensure energy security.

Estimated Transmission Grid Spend

Spend (\$ billion, real 2023)	
2024	2.8
2025	3.8
2026	3.8

Source: BNEF

Energy storage is another area of significant opportunity. Italy's reliance on renewable energy sources means that effective storage solutions are necessary to ensure grid reliability during periods of low generation. A recent development in the sector is the partnership between Emeren Group and Arpinge S.p.A., an Italian infrastructure investment firm, aimed at developing 300 MW of battery energy storage systems (BESS) in the country (Emeren, 2024). Earlier in the year, Emeren Group announced a collaboration with Nuveen Infrastructure to co-develop 199 MW of battery storage projects across two regions in Southern Italy (Nuveen, 2024). Construction for this project is scheduled to commence in mid-2025, with operations anticipated to begin in early 2026.



Outlook

Under its 2024-2028 Industrial Plan, Terna has allocated a total capital expenditure of €16.5 billion over the next five years to enhance and expand Italy's transmission grid, including cross-border interconnection capacity. This plan emphasizes a transition towards a more decentralized grid to accommodate the increasing volumes of intermittent renewable energy from distributed sources (Enerdata, 2024).

Despite a slightly challenging environment, Terna has made notable progress in aligning with the Industrial Plan. In the first quarter of 2024, Terna's capital expenditure reached €482.7 million, a substantial 53.3% increase compared to the same period in 2023. Throughout the first nine months of 2024, Terna continued advancing major projects to improve the efficiency of high and very high voltage grids, alongside ongoing renewal efforts for overhead lines and substation equipment (Terna, 2024).

Climate change is increasingly shaping the design of power distribution grids, particularly in Italy, where record-breaking heatwaves in 2024 have highlighted the severity of shifting weather patterns (Montel News, 2024). These climatic changes are also expected to impact the power transmission sector, emphasizing the need for urgent investments to manage the rising integration of renewable energy sources and enhance resilience against extreme weather events.

Lengthy authorization processes present a significant barrier to advancing grid development projects. In addition to streamlining these procedures, achieving renewable energy targets requires an accelerated approach to finalizing contractual mechanisms that ensure timely construction and lower development costs. To address these challenges, Terna intends to strengthen its collaboration with the administrative bodies

responsible for renewable energy system authorizations, aiming to expedite approvals and support project implementation (Terna, 2023).

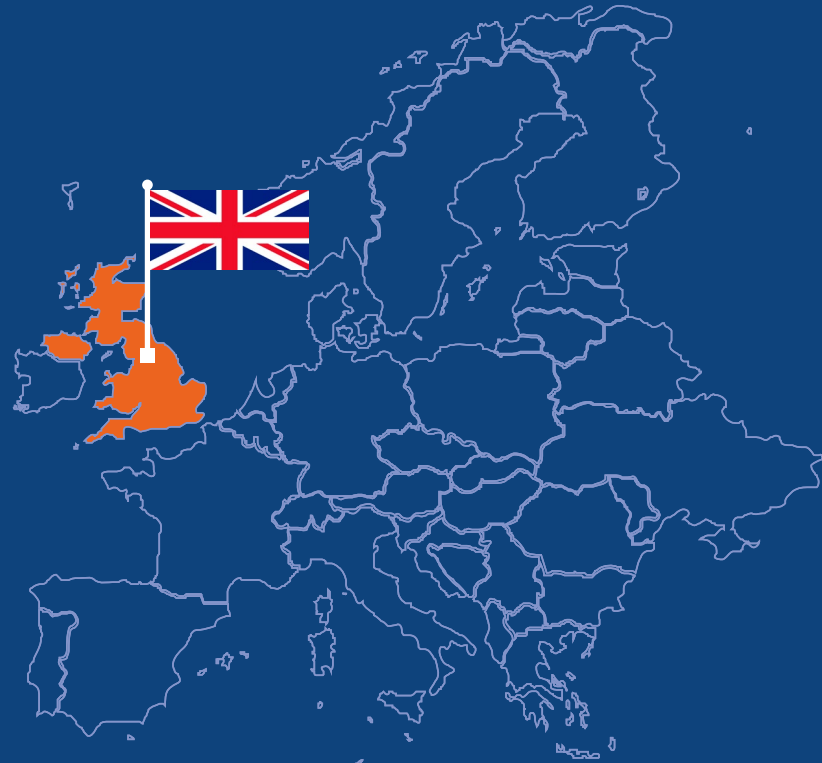
Terna is receiving public funding from the National Recovery and Resilience Plan and RepowerEU to improve the safety and resilience of Italy's National Transmission Grid. This funding supports efforts to reinforce 1,500 km of transmission lines against extreme weather and initiate grid digitization for enhanced operational security and reliability. Additionally, Terna is working closely with European counterparts to advance shared decarbonization objectives across the region (Terna, 2024).

Italy's energy transition increasingly depends on building efficient, digitized grids to manage the technical and operational challenges it brings. The transmission network faces rising congestion as renewable energy sources expand. Therefore, targeted investments in transmission infrastructure are crucial to support the changing energy mix and maintain grid reliability.



UNITED KINGDOM

The UK's power transmission infrastructure is a crucial element of the policy goals of Net Zero and power sector decarbonisation. Recent steps in the policy and regulatory framework aimed at hastening the project development process point to the rising urgency. The step-up in planned grid expenditure is in line with the massive jump required to accommodate upcoming renewable power generation, especially those in offshore wind power. Much more may be needed to get the required grid connectivity for developers, as mounting waiting times may impact the project pipeline.



GDP
(Current Prices, \$ 2023)

3,382 Bn

Projected Average GDP
Growth 2024-28

1.4%

10-Year Govt. Bond Yield
(12-Month Rolling Average)

4.1%

Country
Credit Rating

AA

Renewable Energy
Share

45%

Total Transmission Line
Length (Km)

18,770

Note: Renewable Energy Share excludes hydropower



Transmission Network

The transmission network in England and Wales, managed by National Grid, comprises about 7,200 km of overhead and 1,400 km of underground lines at 275kV and 400kV voltage levels (National Grid, 2024). In Scotland, the transmission licences are held by Scottish Power Transmission Limited and Scottish and Southern Energy, which own and manage line length of 5,100 km (SP Energy Networks, 2024) and 5,070 km (SSE, 2024), respectively.

The cross-border interconnector lines constitute an important segment of the transmission network. Lately, power imports have assumed a major role in the country's cross-border transactions. As of end-2023, the UK power system imported 33,000GWh and exported 9,000GWh (UK Govt, 2024). The cost-effective energy resources of countries such as France (primarily nuclear-based) have been tapped to meet domestic requirements. The UK-

Denmark link is the latest interconnector to be commissioned in the UK's cross-border power infrastructure.

The transmission grid operator is an independent entity that does not hold any ownership stake in the network assets. The UK's regulatory framework also provides for independent private ownership of offshore power transmission systems under the offshore transmission or OFTO licence. With a rise in offshore wind power projects, the OFTO-based owners are also the major drivers of the network investments. In the onshore part, however, the historical practice of 'connect and manage' has progressively exhausted most of the available spare grid capacity. With the grid upgrade long overdue, the utilities are in a catch-up mode against upcoming renewable power generation (BNEF, 2024).

Cross-border Transmission Linkages

Country Linkage	TSO / Owner	About the Linkage
France-UK	RTE and National Grid	The first link was operationalised in 1986, with two more links added since then.
Netherlands - UK	TenneT and National Grid (UK)	Known as BritNed, built with €600 million investment, a 260 km long HVDC line with 1.0GW capacity, operationalised in 2011.
Norway-UK	Statnett and National Grid	Known as North Sea Link, it is a 720 km long HVDC line with a power transfer capacity of 1,400MW
Belgium-UK	Elia and National Grid	Nemo link, commissioned in 2019, as a 1GW subsea interconnector
Denmark-UK	Energinet and National Grid	The £1.7 billion Viking Link is a 475 mile long undersea and underground line with 1.4GW in power transfer capacity, operationalised in December 2023
Ireland-UK	Eirgrid (owner of East-West interconnector) Mutual Energy (owner of Moyle interconnector)	Two interconnector lines, linking Ireland with Scotland and Great Britain, owned and operated by Eirgrid and Mutual Energy

Source: National Grid



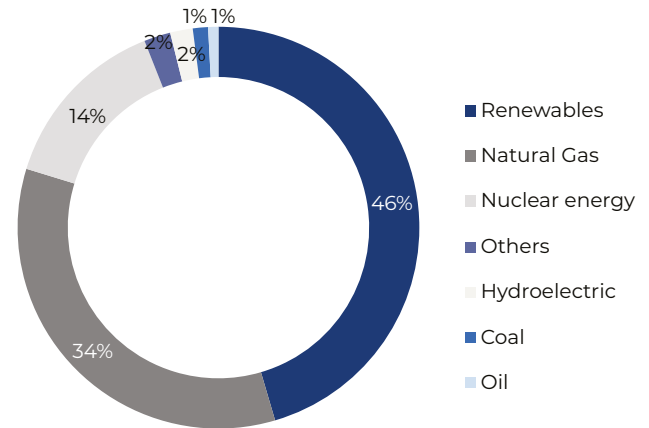
Drivers in Energy Transition

The UK's energy transition progress is guided by the overarching goal of achieving Net Zero by 2050 (UK Parliament, 2024). To this end, the energy sector must be fully decarbonised by 2030, implying a massive renewable energy capacity addition, among other measures. These are ambitious goals that involve a drastic transformation of the energy framework.

As of July 2024, a progress report by the UK's Climate Change Committee (CCC) had findings about the required jump in clean energy generation – by 2030, the country's annual offshore installations should increase by at least three times, onshore wind installations should double, and solar deployments should be increased by six times (CCC, 2024). The CCC's additional suggestions were to hasten electrification in transportation and heating. The progress so far lags against the targeted levels. Between 2018 and 2023, the UK's renewable energy capacity grew at a compound annual growth rate of 4.8% (IRENA, 2024). Annual incremental capacity addition gradually rose in 2022 and 2023 after a sharp decline in 2018.

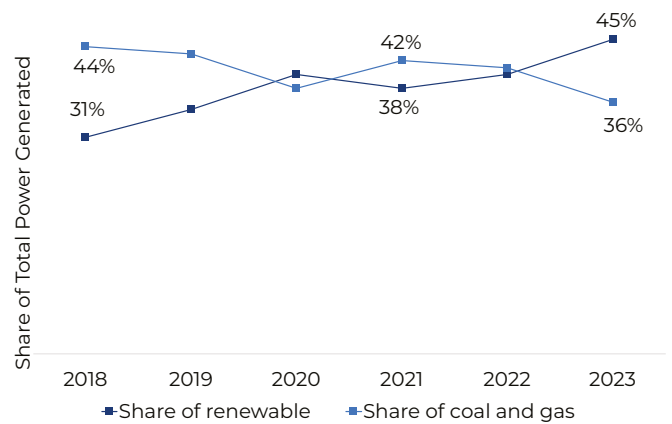
Even with the moderated growth achieved, there are early signs of grid constraints. One such pointer is the grid balancing cost incurred by the grid operator and recovered from the final consumers. For the year 2023/24, it was £2.4 billion. Though lower than the £4.1 billion in the previous year (NESO, 2024), grid balancing costs are poised to rise with the predominance of renewable energy generation. Apparently, wind farm operators are being routinely paid to back down from generation and thus enable grid balancing. It also triggered a regulatory investigation into possible profiteering in the grid curtailment payouts, especially as the cost is levied from the end consumers (REF, 2024). All the same, the fact remains that the existing transmission is

Power Generation Mix



Source: Energy Institute

Transition in Grid-Connected Power Generation



Source: Energy Institute



often unable to absorb the surge in wind and solar generation and relies on the balancing mechanism.

Projection done by UK-based think tank Policy Exchange points to a five-fold rise in the curtailment volume, worth over £3.2 billion, by 2030 if the policy target of renewable energy capacity is met in full (Policy Exchange, 2024). The impending bottlenecks are also evidenced in the grid connection queues. For the year 2024, the total capacity tied in the connection queues is estimated at 800GW (it was over 700GW in actual data till October 2024). There are projects whose waiting time extends to the end of the decade, highlighting the mounting infrastructural challenge (BBC, 2024).

Renewable energy is not the only factor changing the UK's energy mix. Nuclear power is a major policy focus in the decarbonisation framework. In January 2024, the UK government outlined its plan to quadruple nuclear power generation capacity by 2050. It also announced an initial funding of £300 million to support a high-tech nuclear fuel programme, becoming the first country in Europe to do so (UK Government, 2024). Among conventional resources, nuclear power stands out for its emission and long-term costs and is instrumental in reducing dependence on other fossil fuels in the grid.

Presently, natural gas is the only major fossil fuel contributing to a significant share of the UK's energy mix. The decline in its share over time has been marginal, reflecting its continued importance in the grid supply and management process. Among European countries, the UK ranks as the fifth most dependent on gas-based power (ECC, 2024). A sharp reduction in gas-based power would be among the key prerequisites for progress towards decarbonisation. The phaseout achieved in coal is a good example of the way ahead. By the end of 2023, coal had a negligible share of the total power generation mix. In September 2024, its role ended completely as the last such power

plant was closed (Guardian, 2024). This was the 2GW 'Ratcliff-on-Soar' coal-fired power station in the UK's Nottinghamshire, operational for the last 57 years (Enerdata, 2024). The shutdown occurred about a year before the target. It was led in significant part by rising stringency in emission norms and availability of alternate fuel resources.



Policy and Regulation

The UK's government's policy position on Net Zero and its steep decarbonisation targets prompted steps directed at the power transmission infrastructure. An Electricity Networks Commissioner was appointed in July 2022 to advise about accelerating the power transmission network rollout. Since then, there have been key initiatives, such as the Great Grid Upgrade scheme by National Grid to overhaul the existing assets and the Transmission Acceleration Plan to drastically reduce the end-to-end building time of transmission infrastructure. Among other measures in follow-up to the electricity network commissioner's recommendation, the government committed to compensating the homeowners supporting the construction of transmission lines in their properties (Power Technology, 2023).

The critical role of the power transmission was also underscored by the UK government's decision to take control of National Grid's system operator business. With a £630 million deal in September 2024, the UK's electricity system operator business (as distinct from the network ownership) was transferred to public ownership and was rechristened as National Energy System Operator. The new entity was entrusted with both electricity and gas networks. The ownership transfer was guided by not only the need for holistic network planning in line with Net Zero objectives but also to avoid the possible conflict of interest with National Grid's ownership (Guardian, 2024).

There are supportive measures on power transmission from the regulatory side as well. In August 2022, Ofgem, the regulatory body, published guidance for its framework of Accelerated Strategic Transmission Investments (ASTI) as one way to speed up some of the identified projects of strategic importance with modified regulations without compromising consumer interests (Ofgem, 2022). The ASTI framework identified 26 strategic projects,

with estimated costs aggregating £20 billion, to be taken up under a streamlined regulatory approval and funding process. The country's biggest subsea project, Greenlink-2, is one of the ASTI projects that got cost approval in August 2024, making way for its development (National Grid, 2024).

The grid expenditures are generally approved by the regulator based on the regulatory period. The latest rate filings for the power transmission sector refer to 2021-2026. The allowed return on equity varies by grid company benchmarking, with the base rate for transmission set at 6.3% as of 2021. A notable aspect is the total expenditure approach followed in the regulatory assessment of the planned investments. This includes capital and operational expenditures, implying approved returns for those projects that replace capex. In the context of transmission, this could include projects in digitalisation and related technology-based initiatives (BNEF, 2024).



Market Opportunity

The UK's transmission investments are geared towards the Net Zero goals and the corresponding target of full decarbonisation in the power sector. Between 2015 and 2022, the UK's grid investment rose at a CAGR of 5%, averaging \$6.2 billion annually (BNEF, 2024). The projections point to about \$13 billion by 2024, with Scotland's utilities included. National Grid is the single largest investor and has announced a £37 billion investment plan for the period 2025-2029. This is more than double the amount spent by National Grid in the last five years. There are 17 major onshore and offshore transmission projects under various stages of development. Notably, the interconnector line with Denmark, commissioned in December 2023, is the world's longest onshore and undersea HVDC cable (National Grid, 2024).

Grid reinforcement and strengthening are being pursued separately under the ASTI and the Great Grid Upgrade schemes, the latter being a much more expansive framework that would enable ASTI as well as any other projects of similar scope. Major preparatory steps in this regard include supply chain arrangements – HVDC supply chain framework launched for the cabling requirements beyond 2030, partnership with seven industry partners to initially help with the design and construction on nine offshore ASTI projects and finalisation of the joint construction contracts on ASTI projects involving Scotland grid operators.

Offshore investments, led by entities under the OFTO regime, constitute another major segment. For the latest rounds of auctions, the regulatory authority has already notified bidding of ten offshore transmission assets worth £7 billion in 2024 and 2025. The shortlisted entity is guaranteed returns for 25 years, while the project developer is repaid the cost of the asset (Renewables Now, 2023). As policy targets emphasise the offshore wind power potential, the OFTO regime has a significant opportunity.

Estimated Transmission Grid Spend

Spend (\$ billion, real 2023)	
2024	2.6
2025	3.4
2026	3.2

Note: Data refers to the National Grid's capex in England and Wales. It excludes Scottish and OFTO investments.

Source: BNEF

Major Transmission Projects Under ASTI mechanism

Project	Cost	Planning commissioning
Eastern Greenlink-1	\$3.2 billion	2027
Eastern Greenlink-2	\$4.3 billion	2029

Source: BNEF

Investments in grid capacity expansion are also taking place through battery storage. The grid operator's capacity market auctions have lately become a significant catalyst for new battery storage investments. The revenue stream visibility acts as a substantial incentive. Battery storage systems secured 655MW in the capacity market auction held in February 2024, towards the delivery year of 2024/25 (SPP, 2024). Separately, a major investment announcement came from NatPower, a renewable energy startup entity planning £10 billion of capex to set up battery storage of around 60GWh (Guardian, 2024). These developments are indicative of the emerging market opportunity in grid-scale storage, given the rise in renewable energy penetration.



Outlook

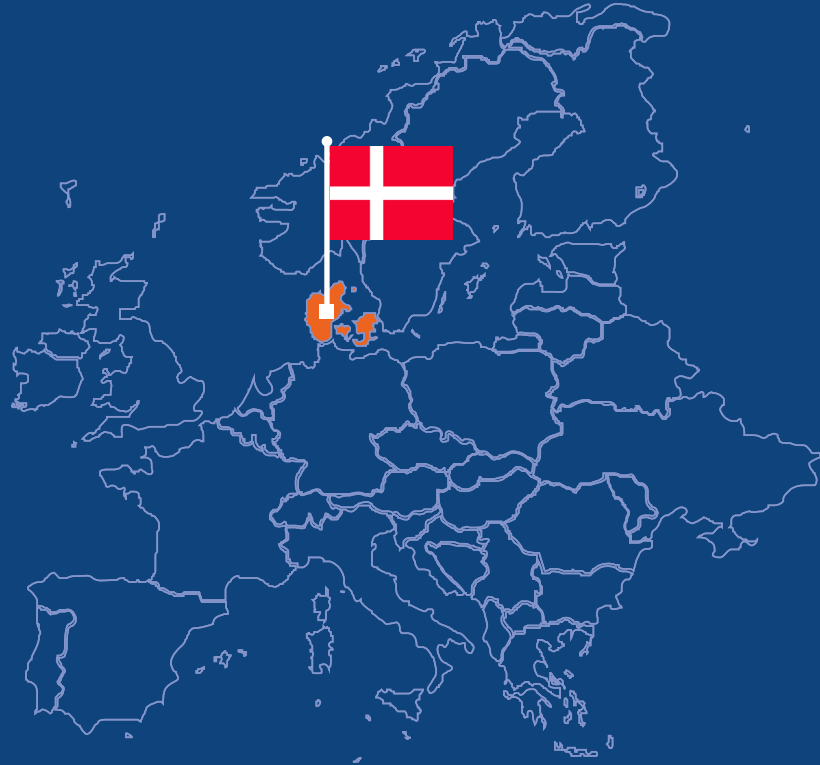
The investment plans drawn by the transmission utilities are aligned with the long-term carbon neutrality targets. The UK's total grid spending by the end of 2024 is likely to be double that of its past average as utilities simultaneously pursue network renovation, replacement, and expansion. Some of the most vital areas of investment focus are those involving grid connections for offshore wind power. With negligible spare grid capacity in major wind power potential regions, such as Scotland, transmission capacity addition is reaching critical levels. BNEF projections point to about 18GW of offshore wind power capacity between 2024 and 2030 (BNEF, 2024). It is also important to mitigate the rising concerns about grid curtailments, primarily of the Scottish wind power exports.

The investment plans run the risk of massive delays. The recent policy steps to bypass some of the procedural requirements for strategic projects highlight the gravity of the issue. As of October 2024, there were 1,100 renewable power projects delayed due to the long grid connection waiting times (Hausch, 2024). Some of the projects have had waiting times extending to a decade, making it absurd. Barring those projects earmarked for fast-tracking, the transmission utility is generally bound by the first-come-first-serve rules in processing the grid connection requests. As things stand presently, there might be a need to rethink the entire process to ease the bottleneck.



DENMARK

With almost 90% of the power generation based on renewable energy resources, Denmark stands out as an outlier among countries for its progress in decarbonisation. Its transmission network, with robust cross-border connectivity, has been playing a key role in enabling the energy transition. However, as the renewable capacity addition continues, it still needs expansion and refurbishment. Furthermore, the exceptionally high renewable energy penetration has also exposed the system to the challenges of curtailment, as evidenced by negative prices. The investment commitments are thus about easing the existing bottlenecks as much as it is for the upcoming generation pipeline.



GDP
(Current Prices, \$ 2023)

407 Bn

Projected Average GDP
Growth 2024-28

1.6%

10-Year Govt. Bond Yield
(12-Month Rolling Average)

2.3%

Country
Credit Rating

AAA

Renewable Energy
Share

88%

Total Transmission Line
Length (Km)

7,000

Note: Renewable Energy Share excludes hydropower



Transmission Network

Denmark's power transmission system operates at voltages ranging from 132kV to 400kV. High-voltage bulk power transmission is predominantly carried out at 220kV and 400kV, while regional transmission grids operate at 132kV and 150kV. Energinet, the sole transmission system operator, manages a network of about 7,000 km in line length as of 2023 (ReGlobal, 2024) (Energinet, 2024).

Between 2015 and 2023, the transmission network experienced a modest growth of 1.9%. This limited expansion is primarily due to Energinet's strategic focus on reinvesting in existing 400kV lines to enhance capacity rather than laying new cables. As part of this strategy, Energinet is transitioning from single to double systems for ageing 400kV connections, effectively replacing them due to age and wear (ReGlobal, 2020).

As Denmark aims to become a net exporter of green energy, strengthening its grid and interconnections is crucial. Hybrid projects and

energy islands in the Baltic and North Seas will be key for exporting offshore wind energy and facilitating power exchanges with neighbouring countries, ensuring stable cross-border energy supply. For instance, the establishment of the Bornholm Energy Island, which will connect at least 3GW of offshore wind capacity to the grid, exemplifies Denmark's commitment to expanding its interconnection infrastructure (Offshore Wind, 2023).

The transmission network predominantly utilises overhead lines for capacity demands amid a rapid green transition. However, policy directives require 400kV connections to be underground where technically feasible. For new 132-150kV connections, the policy mandates their installation as underground cables, aiming to dismantle existing overhead lines in this voltage range in the long run. Furthermore, the policy framework requires existing 132-150kV overhead lines to be placed underground during comprehensive reinvestments, especially when they are near new 400kV overhead lines (Energinet, 2024) (ReGlobal, 2020).

Cross-border Transmission Linkages

Country Linkage	TSO / Owner	About the Linkage
Denmark - UK	Energinet and National Grid (The UK)	The £1.7 billion Viking Link is a 475 mile long undersea and underground line with 1.4GW in power transfer capacity, operationalised in December 2023
Denmark - Norway	Energinet and Statnett (Norway)	Skagerrak HVDC transmission system with multiple links; commissioned between 1976-2015, with a total capacity of 1.7GW.
Denmark - Sweden	Energinet and Svenska Kraftnät (Sweden)	KontiSkan HVDC link, with 250kV and 300kV lines, with a total capacity of 550MW, operational since 1965, two 400kV interconnections and two 132kV interconnections.
Denmark - Netherlands	TenneT and Energinet (Denmark)	Known as COBRACable, with €600.0 million investment, 325 km long, 320kV HVDC line with 700MW capacity, commissioned in 2019.

Source: Energinet, Hitachi, TenneT, Power Technology

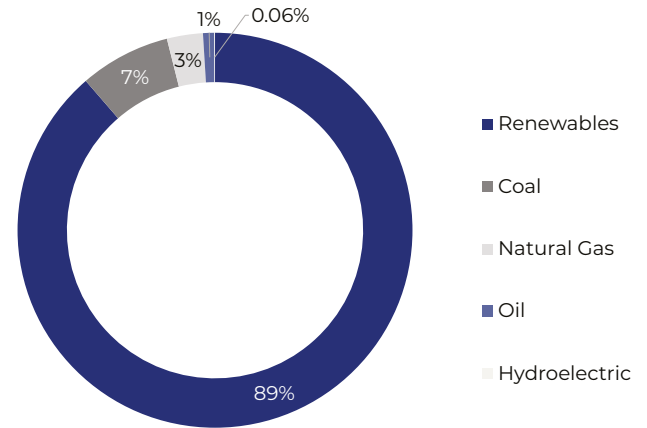


Drivers in Energy Transition

Globally, Denmark leads the way in decarbonisation. The results are seen from the exceptionally high share of renewable energy in the power mix. The national target of reaching Net Zero is 2045 – advanced recently from 2050 earlier, based on the progress in the renewables and overall emission reductions (UNFCCC, 2024). The power sector’s decarbonisation has a central role in this scheme. Thus, a massive capacity addition is underway in renewable power, especially in offshore wind. In April 2024, the Danish government launched its largest offshore wind power tender so far, seeking 6GW-10GW of capacity for planned commissioning by 2030 (S&P Global, 2024). Solar power and biofuels are other major segments driving the shift in clean energy-based power generation.

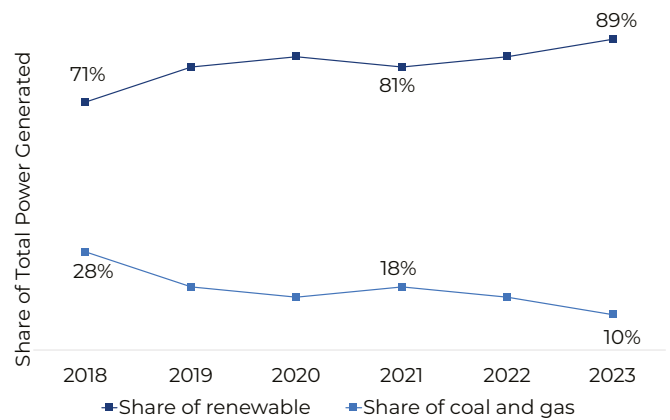
The Danish grid has been managing high renewable energy penetration while maintaining unaffected reliability standards. Its cross-border integration with other power markets helps. A recent example stands out. Since July 2023, Denmark and Germany have implemented a countertrade agreement in their power market transactions. This helped avoid curtailment of Danish wind power generation as it shifted to the intraday cross-border power market (Renews Biz, 2024). The grid operator’s ancillary services market is the other route through which grid imbalances are managed. Energinet is also part of the European region’s integrated balancing market services (Montel, 2024).

Power Generation Mix



Source: IEA

Transition in Grid-Connected Power Generation



Source: IEA



To be sure, the Danish system is forced to curtail renewable power to manage capacity constraints. A clear reflection of such challenges lies in the rising instances of negative prices in the grid. In 2023, it set a record with 512 hours of negative prices in the grid. During the period of January-August 2024, the total time logged for negative prices reached 502 hours, indicating the year-end figure might be considerably higher than the previous year (en.365Nyt, 2024). From the grid capacity perspective, the expansion and strengthening of the network assets assumes a major focus to help stabilise the power markets.

Capacity constraints may feature more prominently as fossil fuel-based generation is phased out. The Danish system presently has just one coal-based power plant, the Nordjylland Power Station, after the company Ørsted shut its last coal-based combined heat and power facility in August 2024 (Balkan Green, 2024). Many such plants are being converted to biomass-based units, indicating the renewable-led push in the market. Gas-based power facilities are undergoing similar pressures to reduce their role in the grid-connected supply. The country's biogas and biomethane resources are increasingly replacing natural gas not only in power but other industrial uses, with a full phaseout expected by 2030 (Danish Energy Agency, 2024).

The power system must also prepare for a spike in future demand. In a recent study, the country's energy agency projected power demand trebling between 2023 and 2035, to reach 127TWh. The major demand segment identified in this study is electrolyzers using renewable power to generate hydrogen and other green fuels (e.g. sustainable aviation fuel). Electricity requirement for this segment is projected to rise from the present negligible levels to 15.8TWh by 2030 and 59.2TWh by 2035 (Montel, 2023). Beyond this, other key sectors of power demand include data centres, heat pumps and transportation.



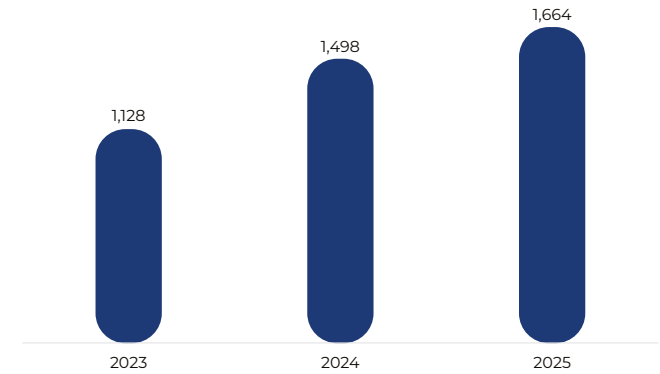
Policy and Regulation

Being an independent public enterprise wholly-owned by the Danish state under the Ministry of Climate, Energy, and Utilities, Energinet's regulatory framework emphasises cost recovery rather than profit generation. Energinet's electricity tariffs are user fees, not taxes, designed to cover the costs of establishing, maintaining, and operating Denmark's public electricity grid and balancing the system. The Danish Utility Regulator sets a revenue framework, capping Energinet's allowable revenue, including a regulated return on invested capital. Tariffs are adjusted annually to align revenue with actual costs, adhering to a break-even principle. Additional revenues from interconnectors help offset costs and reduce consumer tariffs (Energinet, 2024).

Energinet's electricity tariffs consist of two main components: the transmission grid tariff, which covers the operation and maintenance of the high-voltage grid and interconnectors, and the system tariff, which includes costs for ensuring supply security, system operation, and ancillary services. Customers with their own transformers at the 132/150kV level are charged a reduced tariff. The largest part of the system tariff is for ancillary services that ensure the stability of the electricity system (Energinet, 2024).

Energinet is modernising its tariff design to support Denmark's green transition by shifting from an energy-based tariff (DKK/MWh) to a capacity-based tariff (DKK/MW). This change better reflects the fixed costs of the transmission network, which are more influenced by power demand than energy consumption. The updated design, expected to be approved by the Danish National Regulatory Authority and implemented in 2025, includes a fixed annual capacity fee for customers directly connected to the grid, based on agreed power demand, encouraging optimized usage. A variable

Allowed Revenues for Energinet Transmission Business (in DKK Mn)



Source: Energinet

network tariff for grid losses, tied to spot prices, will promote demand response by reflecting real-time market costs (Energinet, 2024).

Additionally, the growing use of wind and solar energy has increased production-consumption distances, raising grid costs. So Energinet's geographically differentiated tariffs and co-location models, like prosumers and direct lines, can reduce costs and enhance efficiency. Cost-based capacity payments optimize grid use, while integrating renewables with flexible consumption supports a smoother transition to green energy (Energinet, 2024).



Market Opportunity

For the period 2023-2027, Energinet has an investment outlay worth DKK 36 billion till 2027, equating to DKK 9 billion annually for the upgradation and augmentation of the grid. This is much higher than the average investment of DKK 5.3 billion between 2018 and 2023. A major share of this investment is expected to be on network expansion (Renewable Watch, 2024).

Some of the critical material supply contracts are taking shape as the grid operator prepares for the upcoming expansion. In May 2024, Energinet signed a €1.4 billion framework agreement with Siemens Energy for the vital switchgear equipment of 50 high-voltage substations (ReGlobal, 2024) (EuropaWire, 2024). Among the renovation projects, there is special attention towards replacing the ageing submarine cables. One of them is the €65 million cable renovation of the Denmark-Sweden transmission interconnection. Contracts in this regard have been signed with JD Contractor A/S for installing 400kV cables and another with Hellenic Cables to design, manufacture, and supply 30 km of submarine cables and 12 km of underground 400kV single-core cables. The project is aimed for completion by 2027 (Offshore Energy, 2024) (Offshore Energy, 2023).

Funding arrangements are also being prioritised. Energinet has a 10-year loan agreement worth €134.4 million, to co-finance the construction of ten new substations and the refurbishment of 45 existing ones, in line with Energinet's government-approved investment and financing plan. This is the second Energinet project financed by the NIB, following the successful completion of the Viking Link interconnection (Nordic Investment Bank, 2023).

Beyond network assets, there is a rising interest in grid-scale energy storage projects, as seen in the recent investment commitments. Green Energy Vault has announced plans to invest DKK 500 million (€67 million) in building one

of Denmark's largest energy storage systems, a 90-MWh facility set to be commissioned by early 2026 (Renewables Now, 2024). Additionally, Better Energy is deploying its first battery storage system, a 10MW/12MWh system, at one of its solar PV plants in Denmark (Energy Storage, 2024). BattMan Energy, a Danish cleantech company specialising in battery storage, has selected Hitachi Energy as the supplier for its three newest plants, collectively generating 36 MW/72 MWh of capacity, with the first two plants targeted for June 2025 (Hitachi Energy, 2024).



Outlook

Energinet's network development plan for 2024-50 lays out the anticipated growth in demand and its required infrastructure expansion. By 2030, the operator projects a requirement of 2,700 km of new-build lines and an additional 3,000-4,000 km by 2050. During the same period, overhead lines spanning 1,000–2,000 km could be removed. The expansion plans include installing 600 km of 400kV connections and strengthening 425 km of existing network. A noteworthy element of the plan is the hydrogen infrastructure development in Western Denmark. The planned development of such an infrastructure will help support the region's offshore wind power capacity but may reduce the need for grid expansion (Energinet, 2024).

Energinet's plans indicate stress on addressing the geographical imbalances as new solar and wind facilities are located far from growing electricity demand centres like cities, Power-to-X plants, and data centres. This necessitates further 400kV grid expansion, with some projects underway and others planned for post-2030 (Energinet, 2024).

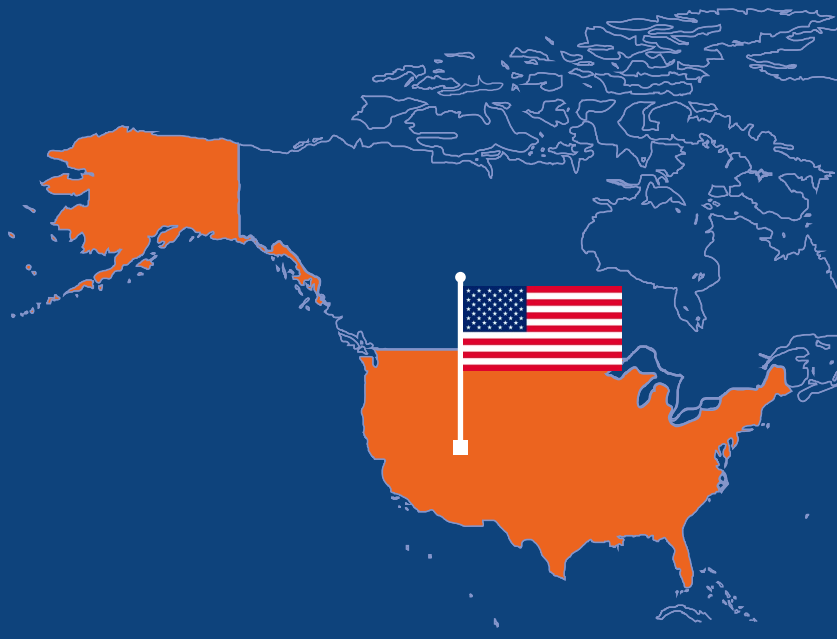
Timely commissioning of the ongoing expansion projects would be crucial. Many parts of the grid are reaching capacity limits. Several developers of the solar parks in Denmark's key locations of Lolland, Falster and South Zealand were asked to wait for the transmission network (Ingeniøren, 2023). This has resulted in developers shelving projects. The risk of delays extends to other key projects. The North Sea Island project, planned originally as a Danish-Belgian project to evacuate offshore wind power in the region, has been delayed by about three years due to cost uncertainty (Reuters, 2024). Costs and material supply chain constraints could impact all projects presently under the planning or development stages, necessitating changes in procurement processes, equipment/component standardisation and efficiency in sourcing strategies (ReGlobal, 2024).

The evolving business conditions will make the planning process a dynamic one. Yet, the direction of growth will be towards a rapid augmentation of the Danish transmission infrastructure to meet the demands of renewable energy and electrification across the economy.



USA

As the world's largest economy, the US power system is massive and comprehensive. Presently, it is in the midst of an unprecedented thrust to expand transmission capacity as fast as possible. Years of stagnancy have placed grid operators in a difficult position to accommodate the exponentially rising pipeline of renewable power generation and energy storage projects. Rising interconnection request queues point to the bottlenecks even when the renewable energy share is far from the targeted levels of 2035 when the power generation is to be fully through clean energy resources. The solutions lie in a mix of policy and regulatory measures, as observed in some of the recent steps at rationalising the approval lead times and financing uncertainties.



GDP
(Current Prices, \$ 2023)

27,721 Bn

Projected Average GDP
Growth 2024-28

2.2%

10-Year Govt. Bond Yield
(12-Month Rolling Average)

4.2%

Country
Credit Rating

AA+

Renewable Energy
Share

16%

Total Transmission Line
Length (Km)

551,400

Note: Renewable Energy Share excludes hydropower



Transmission Network

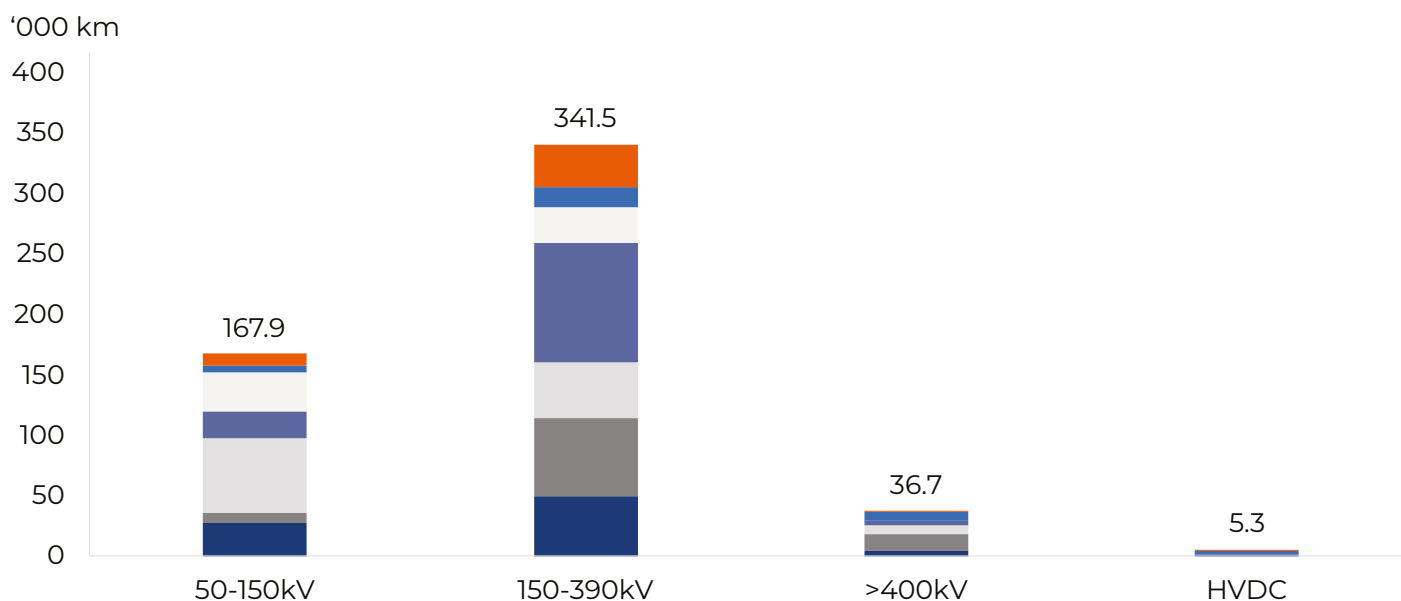
The US power transmission system consists of three major synchronised grid systems – the Eastern Interconnection, the Western Interconnection and Texas. They function largely independently, with limited power exchange between them. The Eastern Interconnection comprises the area from the Great Plains states (excluding most of Texas) eastward to the Atlantic coast. The Western Interconnection covers the area west of the Rocky Mountains and the Great Plains to the Pacific coast. The transmission operations of most of Texas are covered by the Electric Reliability Council of Texas (ERCOT).

It is a fragmented business, with grid operations being carried out by over 1,700 utilities. Some of the system operators stand out for the scale of their operations in the respective grid systems. The California Independent System Operator (CAISO), for instance, controls the largest share of the Western Interconnection. The PJM Independent System Operator is the largest in the Eastern Interconnection. Many utilities holding the transmission networks often operate across the states, thus governed by multiple states' rules.

Over 60% of the total line length is concentrated at 150-390kV voltage levels, while the higher ratings constitute a residual share. It reflects an inadequate capacity added at higher voltage levels typically utilised in long-distance evacuation projects or interregional transmission corridors. There has been a marked slowdown in capacity addition over the years. Between 2010-2014, the network had an additional high-voltage line length averaging 1,700 miles. From 2015 to 2019, the average addition reached 925 miles. The decline from 2020 to 2023 resulted in an average of 350 miles (Clean Energy Grid, 2024).

In the last couple of years, there have been some concerted efforts to fast-track the transmission projects, which can help revive the momentum. The present challenges for grid utilities are, however, severe as they must plan for and manage inadequacy and ageing. The latter is a critical issue – about 70% of the transmission grid assets are 30 years or older (NCSL, 2023) and new transmission lines often have a lead time of 6-10 years or more.

Transmission Line Length



Source: BNEF



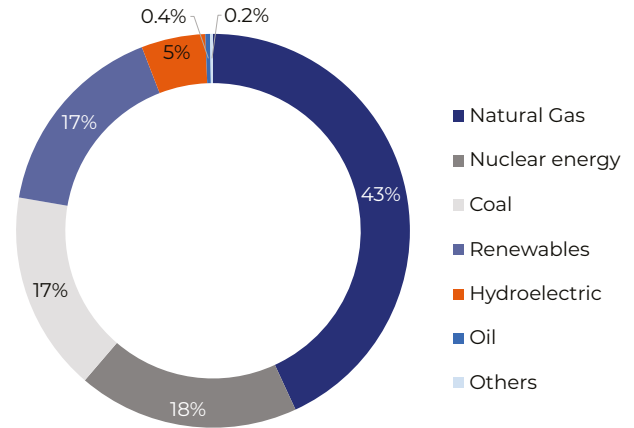
Drivers in Energy Transition

The federal government targets achieving net zero emissions by 2050. This long-term goal involves several interim milestones for decarbonising specific sectors and economic activities. For power sector, the target is to use 100% emission- and pollution-free electricity by 2035 (US Govt, 2024). Some of the major government schemes, such as the Inflation Reduction Act (IRA), are instrumental in such ambitious goals.

The capacity requirements are huge. To achieve the 2035 target, the US power sector would require about 2,000GW of new clean-energy generation and storage capacity (IEA, 2024). Renewable power plays a key role in this equation. IEA's projections for the period 2023-2028 point to 340GW of new renewable power capacity by 2028 – almost equivalent to the total installed renewable capacity as of end-2023 based on estimates of the International Renewable Energy Agency (IRENA, 2024). The capacity addition momentum so far (averaging at 31GW during 2021-2023), while already significant, needs a push forward.

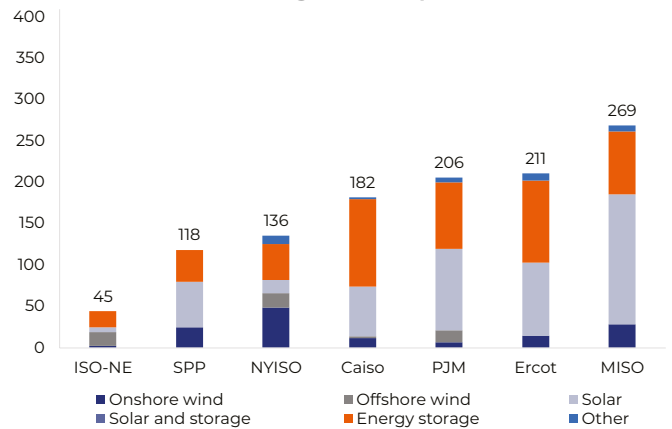
The implications of a rapid renewable power scale-up are already felt in the US power transmission. Most system operators are experiencing a rising interconnection request queue, predominantly for wind and solar power. Grid-scale storage units are the other key players in the queue. By April 2024, the capacity held in queue reached 2.2TW, of which 90% was renewable energy (S&P Global, 2024). Active capacity in grid interconnection queue has risen eight times since 2014 (Renewable Energy World, 2024). The bottleneck is apparent and challenges the power system and investors alike. Reform measures in this regard, especially the regulator's guidelines issued in 2023, are slowly taking effect in some of the power market regions, as indicated by their marginally reducing backlog.

Power Generation Mix



Source: Energy Institute

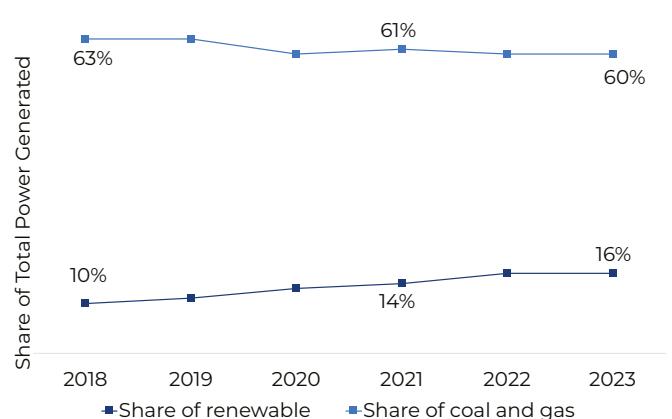
Transmission Interconnection Queue by Power Market Regions/Operators



Note: Data is as of January 2024

Source: BNEF

Transition in Grid-Connected Power Generation



Source: Energy Institute



The grid capacity constraint is also reflected in the curtailment of generation. The intensity varies across power market regions and operators. The US Midwest region's wind power generators, for instance, faced restrictions as supply could not be absorbed in a congested grid. As of June 2024, transmission utilities operating in Southwest Power Pool and Midcontinent Independent Power System Operator curtailed an average of 800MW of wind power. In 2019, the same stood at 200MW (EIA, 2024). The California Independent System Operator has been in the same position – there is a 138% rise in the daily wind and solar energy curtailment volume, reported as of November 25, 2024 (CAISO, 2024).

The signs of grid stress from a transitioning energy mix are all too clear. However, it is striking that this is taking place at a stage when the aggregate renewable energy share is not significant, at least relative to some of the major European countries. Further progress in the energy transition, thus, may need to be balanced against practical considerations. The treatment of conventional energy resources such as coal and gas illustrates this. Coal-based power plants are due for retirement, in line with emission norms and decarbonisation goals. The trend shows a decline in coal, but the rate has slowed down. By 2024, only about 3GW would have been retired. About 14GW is aimed for phase out by 2025 – less than the 16.6GW planned initially (S&P Global, 2024). Policy provisions allowing coal and gas co-firing may enable extensions for a few other coal-based generation capacities in the grid supply. Many generators have also sought to switch from coal to gas, taking advantage of the competitive fuel prices.

Defying expectations in a decarbonising framework, the share of gas-based power in grid supply has risen from 35% in 2018 to 43% in 2023. Utilities' plans indicate capacity expansion in gas-based power. As of May 2024, about 133 new plants were in the planning stages. Some of them are marked as hydrogen-capable plants, making them presentable for regulatory approval in the existing plans (S&P Global,

2024). The shutdown of coal-fired plants in many regions has, in fact, promoted gas-based generation as a reliable alternative (Reuters, 2024).

Conventional power generation, as in coal and gas, finds support from the demand outlook in the US power system. Many utilities are operationalising coal and gas-based power plants to help bridge the possible demand gap. Data centres are the prime movers of the emerging power demand. There is a 15% rise in power demand likely from data centres planned or under development, requiring about 47GW of incremental capacity through 2030 (Goldman Sachs, 2024). In terms of network planning, such a demand outlook marks a sharp reversal from the past trend of flat demand.



Policy and Regulation

The regulatory oversight takes place at the federal and regional levels. The Federal Electricity Regulatory Commission (FERC) regulates all activities related to interstate electricity transmission (besides gas transmission and hydropower licences). FERC sets the transmission rates and the vital market rules for the overall transmission business and delegates many of the granular aspects of the business, such as local planning and development, to the regional authorities. The Regional Transmission Organisations and Independent System Operators oversee the regional power system through activities such as open access, regional planning, mapping generation interconnections and retirements, and administering competitive energy markets (modernizethegrid, 2024). State-level authorities such as the public service and public utility commissions are often responsible for the specific transmission routes through a state-level siting and permitting process.

The policy/regulatory framework is in focus for the required reforms in power transmission. One important point to address is the long lead time in building new transmission infrastructure. In April 2024, the US Department of Energy (DoE) notified rules for a federal programme to consolidate the environmental reviews and authorisations within a standard two-year schedule (DoE, 2024). A pending legislative proposal, the Energy Permitting Reform Act of 2024, is in consideration. It aims to tackle the entire issue of permitting practices in power transmission (among other sectors) with formal regulatory stipulations (Wood Mackenzie, 2024).

Specific policy and regulatory measures are being directed at the planning and permitting process. This includes FERC's order in May 2024 to reform the planning practices and DoE's schemes of the Transmission Facilitation Program (TFP) and the National Interest Electric

Transmission Corridors (NIETC). FERC's order requires each transmission system operator to participate in a regional transmission planning process to identify long-term transmission needs. Both TFP and NIETC were borne out of the US flagship policies of the Infrastructure, Investment and Jobs Act ((IJA) and the IRA. TFP is meant to help finance high-voltage transmission lines, for which IJA allocated \$2.5 billion. Under NIETC, DoE earmarked 10 potential transmission corridors amounting to over 3,500 miles of lines that carried federal backing in their permitting procedures (Clean Energy Grid, 2024). This will likely help rationalise the time taken to secure the procedural approvals.

Transmission planning and its resulting cost allocation have been a longstanding area of contention, on which the regulator had already notified guidance. A couple of recent regulatory developments reinforced its importance. In one such instance, the regulator approved certain incentives for a New Jersey-based transmission project by allocating the cost solely to New Jersey customers. In the other one, a group of cities in Colorado filed a complaint against Xcel Energy's subsidiary company over the utility's plan to allocate the cost of the \$2 billion transmission project to the cities (S&P Global, 2024).

To add to the list of vital issues being reviewed, the regulator recently notified a revised methodology for calculating transmission owners' Return on Equity (RoE). Only two financial models, namely the Discounted Cash Flow and Capital Asset Pricing Model, would be used to determine RoE. The immediate impact of FERC's order was the reduction in MISO-based transmission owners' base RoE from 10.02% to 9.98% (Baker Botts, 2024). Other transmission owners will accordingly reassess their financials for the possible ramifications.



Market Opportunity

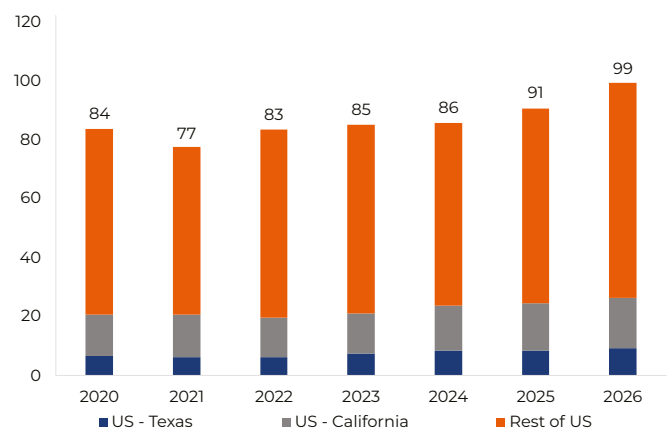
Total grid investment in the US (i.e., transmission and distribution) grew at a compound annual growth rate of 0.5% during 2020-23, reaching \$85.2 billion in 2023. Almost two-thirds of this was in the sub-transmission or distribution segments (BNEF, 2024). The estimated investment for 2024 is also likely to be a modest rise over 2023. However, the outlook for the period until 2026, as per BNEF estimates, points to a 4% growth in investment commitments. A few major power markets, such as California and Texas, stand out for their higher investment growth, projected at a CAGR of 7.5%. Notably both these markets had negligible growth in spending during 2020-2023.

The public funding boost will help catalyse transmission grid investments. Schemes like IRA made over \$30 billion worth of financing available for grid investments through loans, grants, and other support mechanisms. The TFP scheme's \$2.5 billion allocation enables financing large transmission projects through capacity contracts, loans, and public-private partnerships. The capacity contracts, wherein the DoE commits to buying up to half of the project's transmission capacity over up to 40 years, help strengthen investor certainty.

In October 2023, DoE announced that it was entering into capacity contract negotiations with three transmission projects aggregating to 3.5GW in grid capacity. By October 2024, four transmission projects were selected for DoE's capacity contract award, amounting to \$1.5 billion in commitment. The selected projects involve 1,000 miles of new lines and 7,100MW of capacity through the US states of Louisiana, Maine, Mississippi, New Mexico, Oklahoma and Texas (DoE, 2024). The projects must commence construction by December 2029, based on the terms of the capacity contract.

The transmission project pipeline received a further boost from the DoE's NIETC scheme, which marks the high-priority transmission corridors of potential national interest. In May 2024, the list of such projects was circulated. Together, they cover over 3,500 miles across the targeted regions, including the Northwest, Mid-Atlantic, New York and New England, Southwest and Northern Plains. These are in areas where a lack of transmission capacity could potentially raise the cost for end users, or extreme weather could disrupt the grid. The eligible projects of NIETC could avail of direct loans under the Transmission Financing Program expected to start in 2025 (Utility Dive, 2024). The projects would have the regulatory backing in permits, even if they have not received the local or state-level approvals. Importantly, the latest NIETC list overlaps the country's wind energy resource belt.

Power Grid Investments (in \$ Bn)



Note: (1) Data includes transmission and distribution network (2) Data for Texas and California are based on a review of grid plans. Data on the Rest of the US refer to estimates.

Source: BNEF



Outlook

A study by the National Renewable Energy Laboratory (NREL), mapping the scenarios of achieving the targeted 100% clean energy supply by 2035, projected a requirement of over 10,000 miles of new high-capacity lines per year (assuming the construction starts in 2026) (NREL, 2022). The same study estimated the additional cost of decarbonising the power system by 2035 to be between \$330 billion and \$740 billion. The projections indicate the scale of the challenge facing policymakers, regulators, investors, and other stakeholders.

As the project pipeline expands, interregional transmission could be among the most vital to focus on. These projects continue to face hurdles in gaining approvals from multiple state authorities and have also been stuck for the determination of cost allocation among beneficiaries (WRI, 2024). The launch of designated transmission corridors under NIETC is one major step in this direction. There is, however, a significant scope for expanding the investment flow in this segment.

The demand pressure adds to the grid operator's and utilities' concerns. For most of them, the power system needs to be prepared for the rather unanticipated high-demand outlook. The emerging data centre hub in the US and its resulting power requirement are forcing an urgency in grid reinforcement and replacement, as much as feasible. Projections point to at least 2%-3% annual growth in demand through 2030 – a massive departure from the last two decades of near-flat demand growth trend. Besides network infrastructure, the US power demand outlook may also impact the decarbonisation goals. Utilities have already taken to delayed coal retirements and new gas capacities to keep their service reliability levels intact (Wood Mackenzie, 2024).

The outlook of the US power system is, therefore, one of significant flux with several moving parts. Yet, the requirements for the power transmission infrastructure are clear and necessitate progress on a war footing. Some of the recent policy and regulatory measures have been encouraging for their fundamental impact on investments. It remains to be seen how far the bottleneck could be avoided in the ongoing progress for Net Zero.



MEXICO

Mexico's power system remains heavily reliant on fossil fuels, with natural gas playing a central role in its generation mix. Such reliance on gas-powered generation has allowed the transmission operator to maintain grid stability despite the increasing intermittency of renewable energy sources as well as the challenges posed by fluctuating hydropower production. However, the country's transmission network faces critical issues due to an under-invested ageing infrastructure. With a rise in power demand, the existing grid infrastructure is progressively put under stress. There is, thus, an urgent need to accelerate the transmission grid reinforcement and expansion works. To this end, it is vital that the policy and regulatory framework maintain consistency to help attract the requisite magnitude of investments.



GDP
(Current Prices, \$ 2023)

1,789 Bn

Projected Average GDP
Growth 2024-28

1.8%

10-Year Govt. Bond Yield
(12-Month Rolling Average)

9.6%

Country
Credit Rating

BBB

Renewable Energy
Share

16%

Total Transmission Line
Length (Km)

111,030

Note: Renewable Energy Share excludes hydropower



Transmission Network

Mexico's National Power System comprises nine regions and a binational electricity system in Baja California. The nine regions constitute the National Interconnected System, accounting for about 80% of the power transmission. The rest of the system comprises interconnected networks of Baja California, Baja California Sur and Mulege (Climate Scorecard, 2023). The power transmission infrastructure has lately been undergoing changes to adapt to the emerging energy transition.

The power transmission is managed and operated by the state-owned sole operator, the Comisión Federal de Electricidad (CFE). Its network encompasses voltage levels from 69kV to 400kV, with the sub-transmission lines in the range 69kV-138kV lines and high voltage lines operating predominantly in the 161kV-400kV range. Notably, 230kV and 400kV lines constitute more than 50% of the total transmission length (Baker Institute, 2024).

The growth of Mexico's transmission capacity has been slower than anticipated, with the network expanding at a compound annual growth rate (CAGR) of just 0.7% between 2015 and 2024 (CFE, 2024) (CIGRE, 2018). According to the Energy Committee of the International Chamber of Commerce Mexico (ICC México), the country faces a cumulative deficit of 4,370 km of power transmission lines that

Transmission Line Length

Line Length (circuit km)	
2019	110,117
2020	110,293
2021	110,347
2022	110,449
2023	110,558
2024	111,030

Note: Data of 2024 is as of September 2024

Source: CFE

were not constructed between 2018 and 2022 (BNamericas, 2023). This slow pace is due to investment shortfalls and delays in completing planned transmission projects.

A key segment of the Mexican transmission network is cross-border power exchange. Its interregional transmission links with the US, Belize and Guatemala are essential for facilitating cross-border energy trade. Positioned as a key transit country between the North American and Central American markets, Mexico's transmission infrastructure plays a pivotal role in energy imports and exports. With the increasing integration of renewable energy, CFE will need to prioritize the enhancement of these interconnections to effectively manage the grid and ensure efficient energy distribution (UNIDO, 2023).

Cross-border Transmission Linkages

Country Linkage	TSO	About the Linkage
Mexico-US	CFE ERCOT (Texas) CAISO (California)	Mexico maintains 11 interconnections with the United States through the states of Texas and California, via 69kV to 230kV lines, featuring capacities that range from 36 MW to 800 MW
Mexico-Belize	CFE Belize Electricity Limited (Belize)	Since 1998, Mexico has been connected to Belize via a 115kV and 230kV transmission line with a capacity of 65 MW, supplying around 70% of Belize's electricity demand
Mexico-Guatemala	CFE TRESCA (Guatemala)	A 103 km 400kV transmission line connecting Mexico and Guatemala commenced operations in 2010. Plans are underway to integrate it with the Central American Electrical Interconnection System

Source: United Nations Industrial Development Organization (UNIDO)



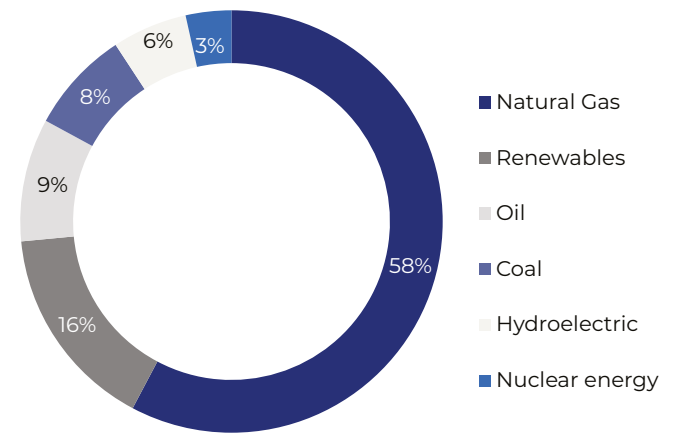
Drivers in Energy Transition

Mexico is one of the most fossil-fuel dependent countries in the Americas, with a heavy reliance on energy sources like natural gas, especially for powering key industrial sectors such as iron, steel, glass, and petrochemicals. Despite this, the country has made progress in transitioning towards cleaner energy. From 2018 to 2023, renewable energy generation grew at twice the rate of fossil fuel generation, expanding by 9.5% annually compared to 4.3% for fossil fuels (IRENA, 2024) (Reuters, 2024).

Mexico's energy goals require an acceleration of renewable energy growth. The policy target is to generate 35% of its electricity from renewables by 2025 and add 30 GW of renewable capacity by 2030 (Reuters, 2024). While the 2013 Energy Reform encouraged private investment in renewables, recent shifts in policy have focused on protecting state-owned companies like CFE, slowing the development of renewable energy projects. As a result, fossil fuels, particularly natural gas, continue to dominate Mexico's energy mix, and the transition to renewables is expected to progress slowly (Power Mag, 2024).

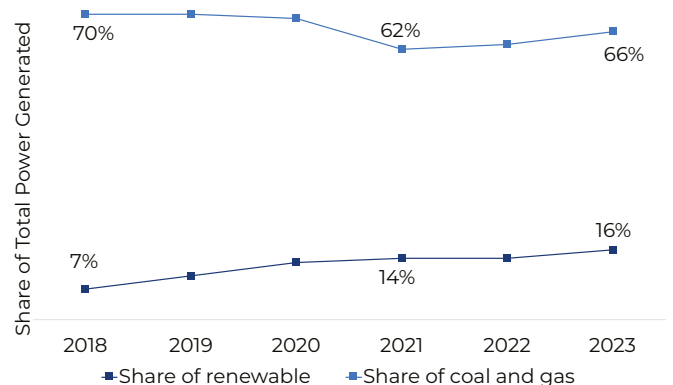
Integration of renewable energy has posed reliability challenges for the grid operator, compelling it to rely on fossil fuels to fill capacity gaps. In 2023, fossil fuel-powered electricity generation reached record levels, driven by a significant decline in hydroelectric output to 20-year lows and relatively stagnant wind energy production. However, increasing environmental awareness and international pressure to meet Mexico's Paris Agreement commitments are expected to accelerate renewable energy adoption. To support this transition, upgrading the national grid to efficiently manage a higher proportion of intermittent renewable energy sources will be crucial for CFE (Reuters, 2024) (Climate Scorecard, 2024).

Power Generation Mix



Source: Energy Institute

Transition in Grid-Connected Power Generation



Source: Energy Institute



Despite limited grid capacity, renewable energy curtailments are significantly low. This may be partly related to the grid management framework placing renewable energy on a priority dispatch order. Fossil fuel-based generation comes lower in dispatch priority order, thus helping the utilisation of wind and solar projects (Chambers and Partners, 2024). This may, however, change in future as there are active considerations to provide CFE the authority for grid dispatch – it may allow CFE's conventional power plants to gain priority dispatch in the available transmission capacity (NGI, 2024).

The National Electrical System Development Program (PRODESEN 2024-2038) forecasts a 38.2% rise in electricity consumption and a 54.91% increase in on-peak demand by 2038. Between 2024-2027, 25.3GW of new capacity will be added, with ~18.0GW from renewables, led by battery storage (5.5GW), wind (5.0GW), and PV-Solar (3.9GW). The plan highlights the growing role of wind and decentralization, with PV-DG reducing reliance on transmission infrastructure. Smart grids and digitalization are critical for integrating intermittent renewables into the grid, emphasizing the need for a balance between decarbonization and decentralization (S&P Global, 2024).

Policy and Regulation

The transmission sector in Mexico faces significant regulatory challenges, primarily due to policy ambiguity and insufficient investment. The transmission network has been underfunded as compared to the budget allocated to generation and CFE's overall budget since the 2014 energy reform. This underinvestment has hindered the alignment of projects with the business plans of transmission and distribution, limiting the sector's growth potential (Mexico Business, 2024).

To address these issues, policy corrections are being considered. For example, it is suggested that the Ministry of Finance ensure labelled resources for transmission projects in the CFE's annual budget, prioritizing them as strategic goals to boost economic growth. Additionally, the government plans to introduce administrative simplifications, including a one-stop shop for energy sector permits and authorizations, aimed at reducing bureaucratic hurdles, costs, and processing times. These measures are intended to enhance the transmission sector's capacity to meet growing energy demands and support Mexico's development opportunities (Norton Rose Fulbright, 2024).

Also, the National Strategy for the Electric Sector 2024–2030 seeks to address the issue of self-sufficient companies (autobasto) avoiding network usage charges. The proposed framework includes implementing appropriate charges to ensure all users benefiting from the grid infrastructure contribute their fair share. This approach promotes fair compensation for grid services while maintaining incentives for distributed generation, ultimately aiming to strengthen CFE's financial stability by reducing the ability of private producers to bypass full tariff obligations (Baker Institute, 2024).



Market Opportunity

The Mexican government, under the National Strategy for the Electricity Sector 2024-2030, aims to invest \$23 billion in the CFE. This investment plan includes \$7.5 billion for transmission infrastructure. The proposed investments are much higher than the annual investments in the sector which have ranged between MX\$3 billion and MX\$6 billion (US\$166 million to US\$332 million) over the past 10 years. As part of the strategy, the transmission grid will be upgraded to meet the growing demand, improve efficiency, and advance renewable energy integration across the country (Enerdata, 2024).

The proposed investment is likely manageable by CFE, as evident from its credit ratings, due to the strong sovereign linkage with the Mexican government. This linkage is reflected in CFE's rating of 'BBB-', which aligns with the country's sovereign rating. Given the company's critical

role in Mexico's electricity system, particularly as the sole electricity marketer to unqualified users and its exclusive control over transmission and distribution, the government has a strong responsibility to support CFE in case of financial distress (Fitch Ratings, 2024).

Grid maintenance and enhancement is another focus area of investment for the transmission sector. CFE plans to invest MX\$2.903 billion (~US\$170.76 million) between 2024 and 2026 to improve Mexico's transmission infrastructure. This includes MX\$969 million for 399 transmission lines, MX\$970 million for 678 sub-transmission lines, and MX\$964 million for vehicles to reduce downtime in the RNT. This investment, a significant increase from 2023's MX\$15.2 million, addresses concerns about the aging grid's ability to support Mexico's growing renewable energy capacity and nearshoring demands (Mexico Business, 2024).

Major Transmission Projects in Pipeline

Project	Length	Voltage	Particulars
Leona Vicario Entq, Dzitnup-Riviera Maya (Quintana Roo)	39.01km	400kV	The transmission lines, part of the National Electric System Development Program (2022–2036), are in the Benito Juarez and Puerto Morelos municipalities of Quintana Roo
Kantenah Entq, Dzitnup-Riviera Maya (Quintana Roo)	42.7km	400kV	Located in the municipalities of Solidaridad and Puerto Morelos in Quintana Roo, near Playa del Carmen, the project aims to support the expansion and modernization of the national transmission grid
Las Mesas-Huejutla II (San Luis Potosi and Hidalgo)	45.9km	115kV	Located in the municipalities of Tamazunchale and San Martín Chalchicuatla in San Luis Potosí and Hidalgo, the project aims to meet the increasing energy demands of the Tamazunchale and Huejutla region while fostering sustainable development and ensuring environmental protection



Las Mesas (Tamazunchale)-Jilotepec Potencia (State of Mexico, Hidalgo and San Luis Potosi)	186.7km	400kV	Traversing the states of Mexico, Hidalgo, and San Luis Potosí, the project aims to expand the electrical infrastructure to ensure a reliable power supply
Culiacan Poniente-Mazatlan Dos (Sinaloa)	253km	400kV	The project will connect the Culiacán Poniente and Mazatlán Dos substations, addressing the power needs of the northern, northwest, and western regions of Mexico
Mazatlan Dos-Tepic Dos (Sinaloa and Nayarit)	257.4km	400kV	The project will connect the Mazatlán Dos and Tepic Dos substations, passing through several municipalities in Sinaloa and Nayarit, deemed essential to meet the anticipated increase in energy demand in the region

Note: The estimated investment in developing these six new transmission lines is MX\$1.8 billion (US\$107 million)

Source: Mexico Business

Additionally, the Mexican government’s plan to mandate energy storage solutions for renewable energy projects presents a key opportunity for the sector. A proposed “30% backup” requirement would compel projects to incorporate storage systems covering part of their generating capacity. However, the successful rollout depends on a clear regulatory framework, which the Energy Regulatory Commission (CRE) is developing, with updates

expected in 2024. These regulations aim to clarify private sector participation and acknowledge the critical grid services energy storage provides. With estimates indicating a need for 2.3GW of new capacity by 2034 to prevent grid issues, energy storage in Mexico emerges as a promising field for innovation and investment (Norton Rose Fulbright, 2024) (PV Magazine, 2024).



Outlook

Mexico's PRODESEN 2023-2037 aims to strengthen the transmission network by adding 1,800 km of 400kV lines by 2032 (Mexico Business, 2024). However, this expansion may not be sufficient to optimize the grid. According to the Energy Committee of the International Chamber of Commerce Mexico (ICC México), to sustain a 2.4% annual GDP growth over the next 15 years, Mexico must invest MX\$2 trillion (US\$112 billion) to deploy 59,000 km of transmission lines and generate over 100GW of energy. This requires an annual investment of MX\$132 billion, including 800 km of transmission lines per year for every percentage point of growth in the national income (BNamericas, 2023). To meet these targets, CFE must expedite approvals for delayed projects and plan additional initiatives.

Apart from being able to execute its plans to add capacity, Mexico's electricity transmission sector also grapples with ageing infrastructure, leading to frequent network failures and blackouts, as witnessed in the recent past. These disruptions highlight the critical need for significant investments to modernize the transmission network. As Mexico also sees an increase in energy demand due to trends like nearshoring, the pressure on the existing infrastructure intensifies. The country urgently requires both increased investments in transmission upgrades and the implementation of innovative solutions to improve energy efficiency (M&A Community, 2023).



CANADA

Canada aims to achieve fully clean electricity generation by 2035. Its present energy mix, based on hydropower and nuclear energy, puts it in a strong position to decarbonise the power sector. However, phasing out fossil fuel generation and adding renewable power generation capacities requires a transmission network expansion and reinforcement. This may require a concerted policy approach, especially when the transmission business operates in a fragmented structure involving vertically integrated utilities spread across provinces. The historically stagnant nature of investment commitments must give way to a spike in spending for a fast-tracked network rollout.



GDP
(Current Prices, \$ 2023)

2,142 Bn

Projected Average GDP
Growth 2024-28

1.9%

10-Year Govt. Bond Yield
(12-Month Rolling Average)

3.4%

Country
Credit Rating

AAA

Renewable Energy
Share

9%

Total Transmission Line
Length (Km)

166,000

Note: Renewable Energy Share excludes hydropower



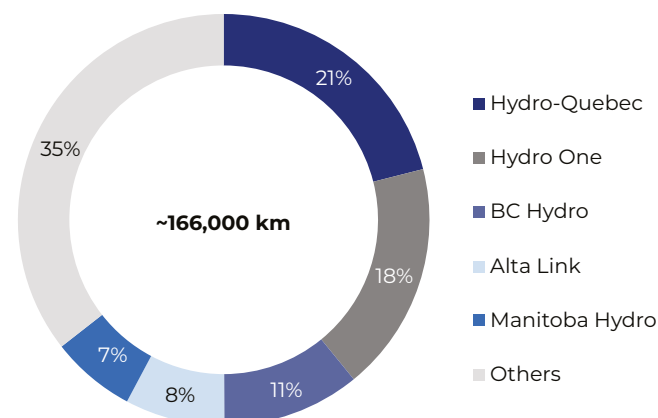
Transmission Network

Canada's power transmission is managed by publicly and privately owned utilities (Canada West Foundation, 2023). Apart from Alberta, most provinces have vertically integrated utilities overseeing transmission grids and generation (Canada West Foundation, 2023). In Alberta, unbundled utilities handle transmission and distribution, while generation is through a competitive, energy-only market. In terms of total network line length capacity, five utilities account for almost two-thirds of the total installed line length capacity.

The Canadian power system's cross-border trade is entirely with the US and maintains a net export balance. The power trade, with 1,522 km of cross-border transmission line length, is predominantly led by hydropower generation in the Canadian provinces of Quebec, Ontario, Manitoba and British Columbia. Dependence on hydropower is also subject to fluctuations, as observed in the 46% fall in net exports in 2023 due to abnormally dry weather (CER, 2024).

Utilities are gradually overhauling ageing network assets as a major focus. Over the

Major Utilities by Transmission Line Length



Note: Data involves approximations.

Source: CER, Alta Link, Hydro One, BC Hydro and Manitoba Hydro

years, most have made minimal investments in expanding or reinforcing the grid. The resulting constraints are much more pronounced in a scenario of changing energy mix and rising power demand. Interregional links, for instance, are grossly inadequate. This prevents any economical utilisation of surplus generation and transfer of resources for grid management and emission levels.

Cross-border Transmission Linkages

Country Linkage	TSO / Operator	About the Linkage
Canada (Quebec) - US (New England)	Hydro Québec National Grid USA	1480 km long, ±450kV HVDC line with 2,000MW capacity in operation since 1986.
Canada (Quebec) - US (New York)	Hydro Québec	Enables interconnection of the 735kV Canadian and 765kV New York grids with a transmission capacity of 1,500MW; operational since 1984.
Canada (Manitoba) - US (Minnesota)	Manitoba Hydro Minnesota Power	A 360km long 500kV AC transmission link capable of transferring up to 800 MW of electricity and has been operational since 2021.

Source: Hitachi Energy, EMF Portal, T&D World



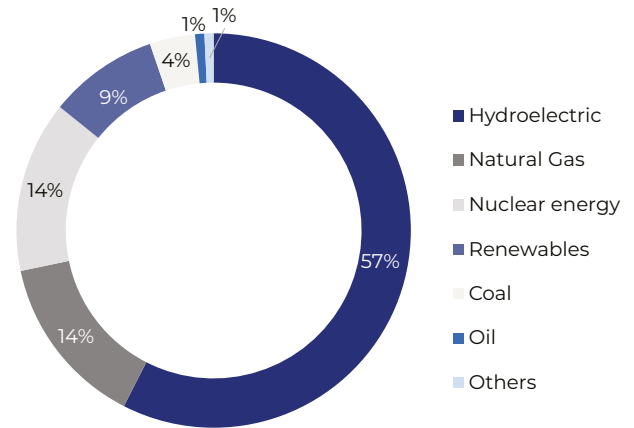
Drivers in Energy Transition

Canada’s long-term target of achieving net zero by 2050 involves a key milestone of decarbonising the power sector by 2035. The legal enforcement of the same is likely with the upcoming enactment of the Clean Energy Regulations (Government of Canada, 2024), making it much more credible vis-à-vis the targets determined by the government.

The Canadian power generation segment already enjoys a significantly decarbonised resource base. Over 70% of the total grid supply is based on hydropower and nuclear energy, the former being the largest resource so far. Together with renewable energy, the decarbonised supply’s share stands at 80%. With such a position in the energy mix, renewable power capacities have been late to catch up. An average of 2.4GW was added between 2021 and 2023 due to the prioritisation of renewable energy in the grid (IRENA, 2024). The momentum in renewable power capacity addition is poised to pick up as fossil fuels are phased out of the generation mix.

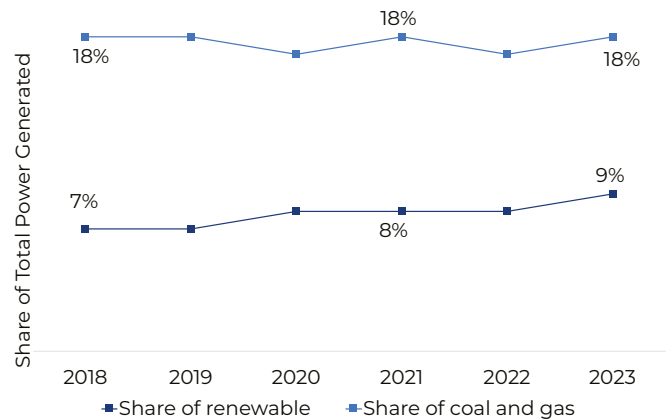
In 2016, the government committed to phasing out unabated coal-fired power plants by 2030 (Global News, 2024). There has been gradual progress since then, as observed in the Canadian provinces. In Ontario, coal-fired generation was eliminated between 2003 and 2014. In Alberta, the last coal-based power plant closed in June 2024 (Forbes, 2024). Other provinces, such as Nova Scotia and New Brunswick, received federal funding to enable the phase-out by 2030 (WNN, 2023). Solar and wind power capacity additions potentially replace the capacities taken offline (S&P Global, 2024). However, natural gas is also contributing to compensating for the loss of coal-based power.

Power Generation Mix



Source: Energy Institute

Transition in Grid-Connected Power Generation



Source: Energy Institute



The trend shows a gradually rising share of gas-based power in the total grid power supply – from 10% in 2018 to 14% in 2023. About 3.5GW of new-build gas-based power capacity is in the pipeline for commissioning in 2024 (as of April 2024). Most of them are meant to replace the coal-fired power plants phased out from the grid. However, this is also an apparent contradiction to the regulatory framework seeking binding targets of decarbonisation. It remains to be seen how gas-based power is reconciled with the decarbonisation objectives.

Clean energy integration in the grid must be done in tandem with expansion to accommodate the upcoming rise in power demand. Besides the economy-wide shift towards electrification, a major segment is data centres planned in many provinces. System operators of the Quebec, Ontario and Alberta provinces have outlined a sharp rise in their power demand over the 7-10 years and are thus provisioning for the same. Notably, Canada's high share of low-carbon grid power is a major draw for prospective data centre developers (S&P Global, 2024).

Policy and Regulation

The Canada Energy Regulator oversees interprovincial and international pipelines and power lines. At the same time, provinces exercise substantial authority over energy matters within their borders, including the regulation of electricity production, generation, transmission, and distribution.

Various provincial regulatory authorities deliberate and approve the rates for the respective utilities, which operate as vertically integrated utilities. Lately, the authorised returns on equity have risen for many of the utilities, reflecting a recognition of the rise in the cost of capital for regulated utilities. It can be related to the rise in the country's benchmark interest rates in the last two years.

In December 2021, the federal government introduced the Clean Electricity Regulations, targeting a reduction in greenhouse gas (GHG) emissions from fossil fuel-powered electricity by 2035. The draft regulations, published in August 2023, propose limiting carbon dioxide emissions from fossil fuel power plants to 30 tonnes of CO₂ per gigawatt-hour by 2035 (Norton Rose Fulbright, 2024). While the final version of the regulations has yet to be released, the proposal has faced criticism, particularly from provinces such as Alberta and Saskatchewan, which depend heavily on hydrocarbon-based electricity generation.

Recent Changes in the Authorised Returns for the Utilities

Operating Utility	Deemed Equity Ratio	Authorized RoE	Recent Changes
Alberta Electric Utilities	37.00%	9.28%	RoE increased from 8.50%; new base RoE is 9.00%; new formula implemented
FortisBC Electric	41.00%	9.65%	RoE increased from 9.10%; equity ratio increased from 40%
Ontario Electric Utilities	40.00%	9.21%	RoE decreased from 9.36% under formula
Maritime Electric	40.00%	9.35%	Raised cap on earnings to 9.70%
Newfoundland Power	45.00%	8.50%	Pending
Nova Scotia Power	40.00%	9.00%	Equity ratio increased from 37.5% due to energy transition risk

Source: Concentric Energy Advisors



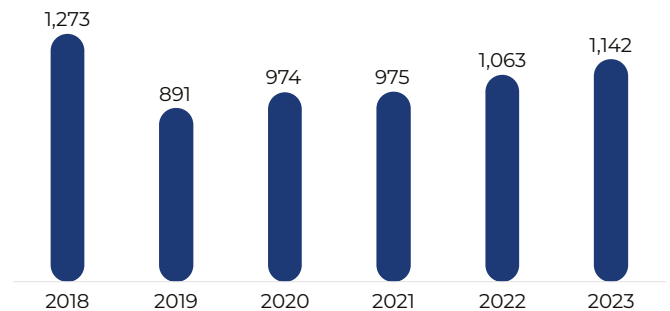
Market Opportunity

Power transmission projects can get funding support under policy schemes covering a wide range of investments towards decarbonisation and net zero. Lately, the federal budgetary allocations have prioritised grid reinforcement and expansion. In October 2024, the government announced added support worth C\$500 million for the Smart Renewable and Electrification Pathways Program (SREPs) Utility Support Stream. The Federal Budget of 2023 recapitalised the SREPs with an allocation of about \$2.9 billion to cover renewable energy technologies, energy storage and grid modernisation. The additional outlay augmented the \$1.5 billion allocated in the Budgets of 2021 and 2022. With this announcement, the Federal government also launched the request for expressions of interest for the Utility Support Stream for the utilities, system operators, and industry organisations. The projects funded in this context would include investment proposals aimed at the reliability, resilience, and flexibility of the power system (Government of Canada, 2024).

The policy support also extends to tax incentives, as laid down in the Federal Budget 2024. The Clean Technology Investment Tax Credit (ITC) is a refundable tax credit for the capital invested in the adoption of new clean energy technology property in Canada from March 28, 2023, to December 31, 2034 (Government of Canada, 2024). For transmission projects between Canadian provinces and territories, the applicable ITC is up to 15% (KPMG, 2024).

The investment funding support is timely because the transmission network requires significant expansion, reinforcement, or replacement to prepare the power system for emerging requirements. Many of the provincial transmission utilities have planned major projects in this regard. Many of the investment plans are also driven by the rising need to build resilience against extreme weather. Also, the legacy grid management practices, borne out of years of depending on fossil and hydropower, are

Power Transmission Network Investments (CAD million)



Source: Statistics Canada

giving way to different approaches to adapt to – for instance, building bi-directional capabilities to accommodate storage units (The Globe and Mail, 2024).

HVDC transmission systems constitute an important aspect of the planned network investments. Reflecting this, in July 2024, the government extended funding support of \$30 million for an HVDC test and simulation facility. This will help Hitachi Energy's power transformer facility in Quebec and enable a new one for HVDC simulation in Montreal. The equipment manufacturing and testing facility could potentially help the material supply chain against a backdrop of global challenges in sourcing power transformers (Recharge, 2024).



Planned Investments by Provincial Transmission Utilities

Province	Transmission Utility	Investment particulars
Ontario	Hydro One	Between 2024 and 2027, a total of \$7.1 billion in investment commitment, based on regulatory approval (Hydro One, 2024).
British Columbia	BC Hydro	The investment plan for the period 2024-2034 is worth \$36 billion in community and regional infrastructural projects, primarily in transmission (T&D World, 2024).
Quebec	Hydro-Québec	A \$50 billion plan to install 5,000 km of line length by 2035. About half of the line length will be at high voltage ratings of 735kV and 315kV (CBC, 2024).
Manitoba	Manitoba Hydro	Joint investment of about \$500 million by the governments of Canada and Manitoba to strengthen Manitoba's grid (T&D World, 2023).
Alberta	Alberta Electric System Operator	The 10-year investment plan for 2022 includes major grid reinforcement projects for the upcoming generation (AESO, 2022).
Saskatchewan	SaskPower	The utility announced \$1.6 billion for the year 2024-25, of which \$508 million was towards maintenance and upgrade of grid assets (SaskPower, 2024).

Source: Hydro One, T&D World, CBC, AESO and SaskPower



Outlook

The policy goal of a net-zero power sector by 2035 requires re-aligning the power transmission sector for changes in the energy mix. Some of the pointers on the emerging outlook could be gleaned from the May 2024 report of the Canada Electricity Advisory Council (CAEC) – a government-convened autonomous body of power sector leaders representing all provinces (CAEC, 2024). It highlights, for instance, that the pressure of power sector decarbonisation might be on a few provinces, such as Alberta, Saskatchewan, Nova Scotia and remote communities of the North due to their dependence on fossil fuels. The power transmission system may thus have a vital role in mitigating such a skew.

Interregional transmission connectivity may be a major area of focus to enable decarbonisation in power generation across all provinces. So far, this has been a neglected segment of the network. As things stand, undertaking cross-border power transactions is easier and remunerative than inter-province power transfers – the volume of power flowing to the US is more than that between the Canadian jurisdictions. A timely capacity expansion in this regard could help address the anomaly.

A study done in 2022, modelling the capacity requirements for Canada's net zero economy by 2050, projected about 6,000km of new or reinforced interregional transmission lines with power transfer capacity worth 29GW (David Suzuki Foundation, 2022). This amounts to an almost threefold rise in the interregional transmission network size. Such a scale of capacity would necessitate a decisive change in the policy and regulatory processes.

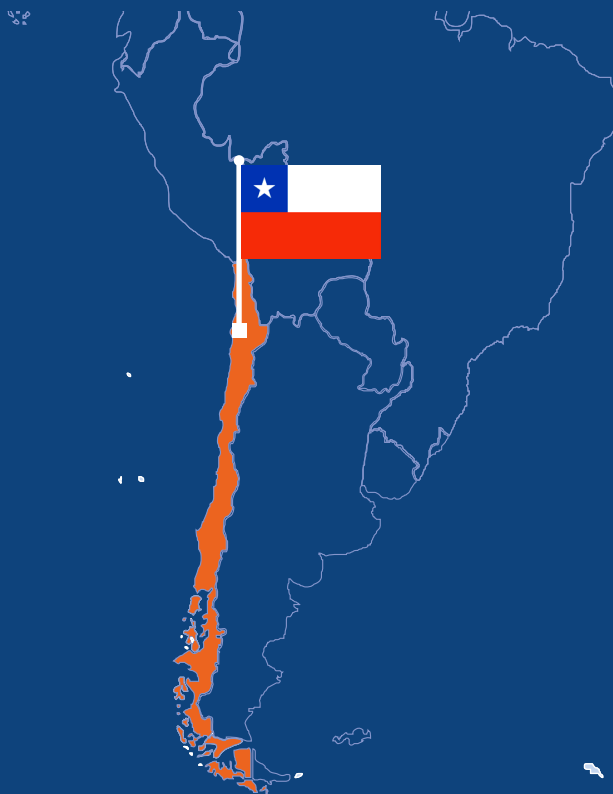
The federal government's policies acknowledge the need to promote transmission. The recently introduced tax credit is important among the planned support measures for power transmission. However, there might be a case for reviewing it. The tax credits presently cover only inter-provincial transmission assets. The CAEC recommended that they should also be available for intra-provincial transmission projects due to their role in network strengthening and connectivity. Beyond incentives, there is an acute need to revisit the permitting processes to rationalise the lead times in building the new transmission assets. Notable among these are the norms which tend to overlap between Federal and provincial authorities.

The transmission utilities' investment commitments point to the efforts underway. The requirements for net zero are tantamount to a complete transformation of the power system's configuration. The challenge might lie in getting the system ready ahead of time to enable a smooth transition towards 100% decarbonised power generation.



CHILE

Chile has made significant progress in integrating renewable energy into its energy mix, which puts it in a strong position to achieve the carbon neutrality target of 2050. However, the rapid growth in renewable power capacities has strained the grid capacity. There is a lag in the transmission network growth, which must be addressed as soon as possible to avoid impacting the generation project pipeline. Policy and regulatory authorities' interventions may become necessary to expedite the multiple transmission projects under various stages of development.



GDP
(Current Prices, \$ 2023)

336 Bn

Projected Average GDP
Growth 2024-28

2.4%

10-Year Govt. Bond Yield
(12-Month Rolling Average)

5.8%

Country
Credit Rating

A

Renewable Energy
Share

38%

Total Transmission Line
Length (Km)

38,784

Note: Renewable Energy Share excludes hydropower



Transmission Network

As of October 2024, Chile's total transmission line network spanned 38,784 km, with most of these lines operating at voltage levels ranging from 66kV to 500kV (CEN, 2024). Chile's transmission sector is largely privatized, with several private companies holding concessions to manage transmission lines and infrastructure. The Coordinador Eléctrico Nacional (CEN) is the primary body responsible for overseeing the operation of the national transmission system under the regulatory supervision of Comision Nacional de Energia (CNE).

Chile's transmission system includes the National Transmission System (STN), Zonal Transmission Systems (STZ), and Dedicated Transmission Systems. The STN serves as the high-voltage backbone, interconnecting systems nationwide, while zonal systems provide local reliability for regulated customers. Dedicated systems cater to unregulated customers and support power injection from generators. As of 2023, 64% of Chile's transmission lines operate at voltage levels of 220kV and above (CEN, 2024) (GLG, 2024).

Chile's transmission network faces rising congestion levels due to modest capacity addition over the years. It is constrained in capacity to connect the renewable energy generation hubs, particularly in the northern regions, with major consumption centres like Santiago. This underscores the need for strategic investments and timely execution of the planned transmission projects, including those related to grid reinforcement (Lexology, 2023) (FYLD, 2024).

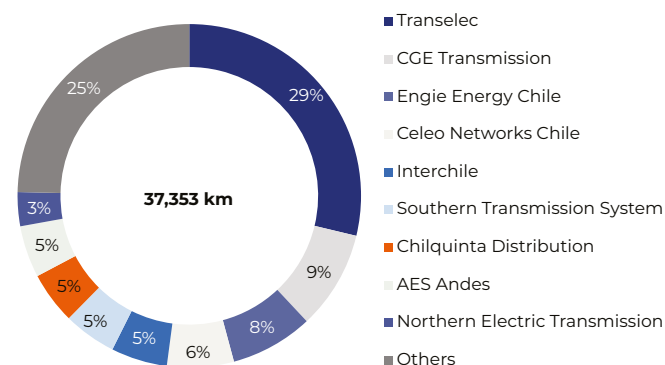
Transmission Line Length

	Line Length (circuit km)
2019	35,501
2020	35,616
2021	36,318
2022	38,160
2023	37,353
2024	38,784

Note: Due to source data limitations, the line length data of 2023 and 2024 do not reflect the complete year. For 2023, it is as of May, while for 2024, it is as of October

Source: CEN

Distribution of Transmission System Operators by Line Length



Source: CEN

Cross-border Transmission Linkages

Country Linkage	TSO	About the Linkage
Chile-Argentina	CEN Transener (Argentina)	Known as InterAndes, 345kV transmission line of 409km between the Andes substation in Chile and the Cobos substation in Argentina with 80MW export capacity from Chile and 200MW import capacity from Argentina

Source: AES Andes



Chile's only cross-border transmission link is with its neighbouring country, Argentina. It helps optimise its energy resources by enabling the export of surplus solar power generation and reducing dependence on fossil fuels during the phases of low demand or grid curtailment (AES Andes, 2022). There are active considerations

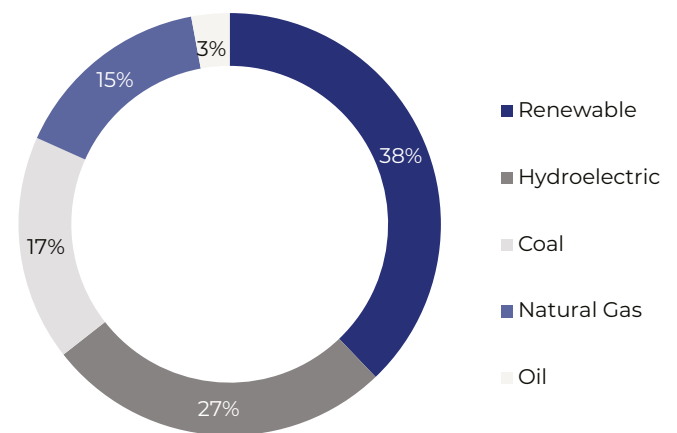
underway to expand the interconnection capacity with other countries, such as Peru and Bolivia, to help grid stability and diversify energy resources. These efforts are part of a broader initiative aimed at building a larger regional and sub-regional interconnection system across Latin America (IDB, 2024).

Drivers in Energy Transition

Chile is progressing toward its 2050 carbon neutrality target, outlined in the Framework Law on Climate Change (2022), by prioritising renewable energy sources such as solar and wind. Through its Energy Transition Agenda, the country increased renewable capacity addition rate from an annual average of 0.9GW (2017–2020) to 3.0GW (2021–2023), driven by solar and wind power (IRENA, 2024) (Gas Outlook, 2024).

Chile's long-term energy planning document, Planificación Energética de Largo Plazo (PELP) 2023–2027 targets 34.8GW of wind, 32GW of solar PV, 7.8GW of concentrated solar power (CSP), and 6.6GW of storage by 2050, while excluding hydropower due to uncertainties arising from water scarcity. It also promotes green hydrogen to decarbonize the mining sector, addressing its high energy demands through indirect electrification aligning with Chile's energy transition and decarbonisation goals (ReGlobal, 2022).

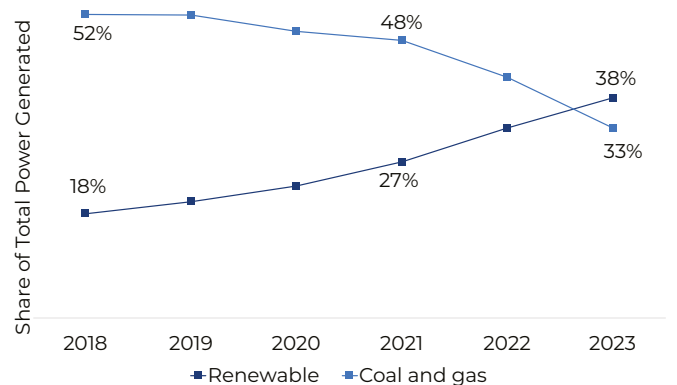
Power Generation Mix



Note: In the above chart, the category 'renewable' includes biofuels, geothermal energy, solar PV, solar thermal and wind power

Source: IEA

Transition in Grid-Connected Power Generation



Note: In the above chart, the category 'renewable' includes biofuels, geothermal energy, solar PV, solar thermal and wind power

Source: IEA



The acceleration in renewable energy penetration is increasingly facing transmission bottlenecks. Often, the grid operator has been forced to curtail significant amounts of renewable energy. In July 2023, 8.9% of renewable generation was curtailed, which rose to 21.2% in December during the peak generation period. The rising mismatch between renewable power capacity and the transmission network prevents the power system from fully utilising the available renewable power generation resource base. With a rise in the renewable power capacity addition pipeline, it may become urgent to provision the necessary grid capacity (Gas Outlook, 2024).

The decarbonisation process is also finding traction with the phase-out of conventional fuels in the energy mix. About 28 coal-based power plants, having a cumulative capacity of 5.5GW, are slated for a shutdown by 2040. By October 2024, 11 units (1.7GW) had already been retired, and by 2026, an additional nine units (2.2GW) are expected to be either retired or repurposed

(Ministry of Energy, 2024). At the present rate, it is likely that the coal-fired power plants could be retired much ahead of the planned date. The gas-based power generation trend, in contrast, has been largely at the same levels. Between 2018 and 2023, it averaged a 17% share of the total power generation. This points to its critical role in grid stability, considering the rising challenges in integrating wind and solar power injection.

Planning for grid stability would also include the demand outlook. The CNE's published timeline for energy auctions from 2025 to 2028 seeks 22,500 GWh for anticipated demand. The grid operator has pointed to potential supply shortages in 2027, with deficits from 2030 due to insufficient contracts. The auctions are aimed at accommodating the growing demand from sectors like mining and electromobility and ensuring reliable supply for distribution companies. (PV Magazine, 2024) (EMIS, 2024).

Policy and Regulation

Chile's electricity transmission revenues are regulated by the CNE, with the National and Zonal Transmission Systems classified as public services and funded by final customers based on construction and maintenance costs. The development of transmission lines uses an auction-based model managed by CEN to ensure efficiency. At the same time, dedicated systems operate through privately negotiated tolling agreements but maintain open access when capacity allows.

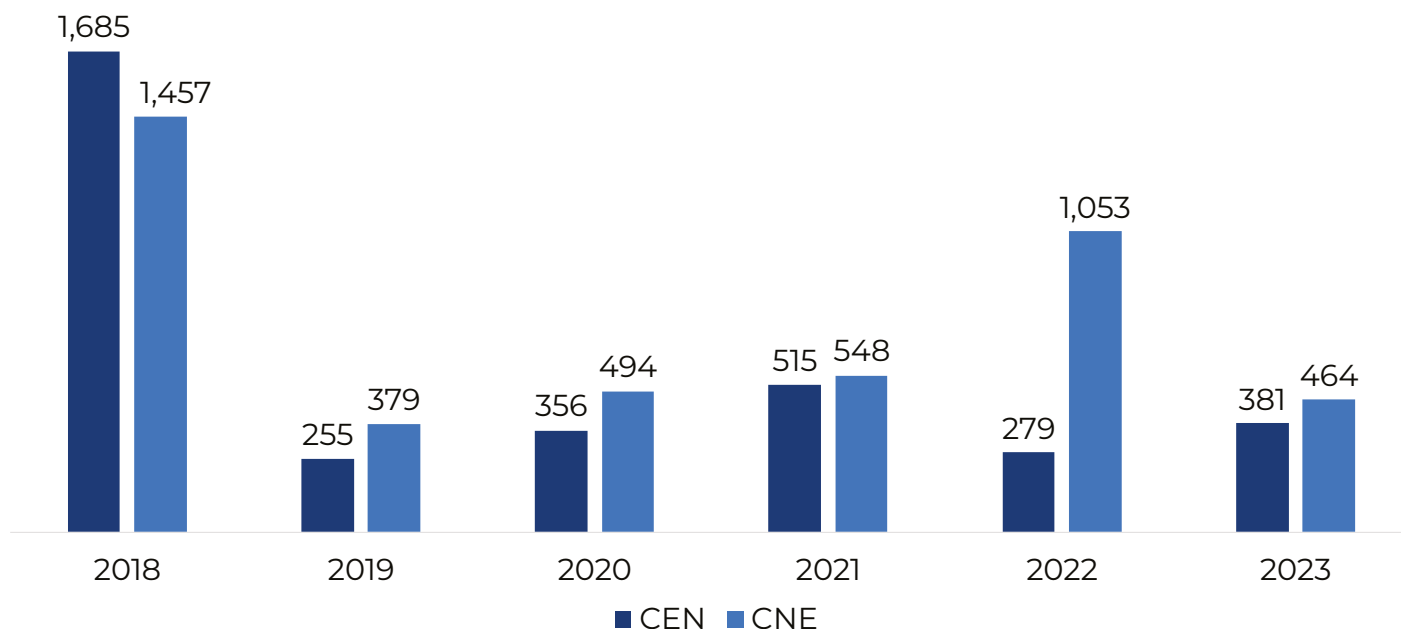
Transmission companies are compensated under the Value-Added Transmission Tariff (VATT), recalculated every four years by the CNE, which considers infrastructure costs, system demand, and a regulated return on investment. This framework supports efficient grid management, promotes private investment through competitive returns, and, at the same time, ensures universal electricity access (GLG, 2024) (C&P, 2024).



Additionally, the CNE reviews and approves the annual investments proposed by the CEN, which is responsible for drafting an Annual Transmission Expansion Proposal to outline its investment plans. This proposal includes a detailed list of all planned transmission projects for the year, covering both new developments and expansion works required to meet the country's energy demands. If additional projects are needed beyond those initially targeted for the year, the proposal is supplemented with a reference investment value for the extra works. The Transmission Expansion Plan is compiled based on the actual works and investments confirmed for a given year (CEN, 2024).

The recently approved Energy Transition Bill aims to accelerate the network expansion rate through measures such as penalties for non-compliance in power purchase agreements and clarifying storage regulations. Additionally, the Ministry of Energy has initiated an "Open Season" mechanism to expedite the development of critical transmission system expansion projects. This process is designed to streamline the identification and approval of urgent works required to enhance grid capacity. Alongside, there is a thrust on grid modernisation by promoting major grid-enhancing technologies like dynamic line rating and real-time capacity optimisation (GLG, 2024) (C&P, 2024) (BN Americas, 2024).

Transmission Network Proposals and Investments (\$ million)



Source: CEN



Market Opportunity

During the period 2021-2025, there have been tenders for about 300 transmission projects worth \$3.2 billion. This investment marks a sharp increase compared to the previous period of 2011-2019, where about \$2.8 billion was allocated for transmission development. These high-voltage network projects are critical to supporting the growth of renewable energy, led by solar and wind power, besides helping augment the grid capacity for the rising power demand (Renewable Watch, 2021).

In its 2024 Transmission Expansion Plan, CEN proposed an investment of \$1.004 billion, more than doubling the allocation from the previous year's \$464 million. The plan comprised 91 projects, divided into national and zonal transmission segments. The national transmission system had 13 projects, involving

investment of \$501 million, while the zonal system had 78 projects with a budget of \$503 million. Notably, the high-voltage direct current projects, such as the 1,342 km long Kimal-Lo Aguirre line have been in evaluation but were excluded from the 2024 plan due to cost concerns (BNamericas, 2024) (CEN, 2024).

Additionally, CEN has outlined an energy storage expansion strategy for 2025-2032 to enhance grid reliability. The plan identifies the northern regions as optimal for storage facilities, given their proximity to renewable energy plants and mining activities. A recommended initial capacity of 2,000MW (equivalent to 13.2GWh) by 2026 requires an investment of \$3.2 billion but is expected to save \$500 million in operational costs and reduce energy cuts by 40% (PV Magazine, 2023).

Major Transmission Projects in Pipeline

Project	Investment	Segment	Commissioning
New S/E Sectioning Switch The Noviciado 500/220kV and New Line 2x220kV The Novitiate – The Campino	\$116.0M	National	2033
New 2x220kV Line Calama Nueva – Mirage	\$45.7M	National	2033
New 2x220kV Line Sentinel – Kimal	\$42.5M	National	2031
Increase in capacity of the 1x110kV Mejillones line – Tap Off Desalant	\$22.5M	Zonal	2030
New 2x66kV Line Fuentecilla – Aldunate (1 st row)	\$21.7M	Zonal	2031
New Los Muermos 66/23kV substation and New 1x66kV Los Muermos line – Tineo	\$21.6M	Zonal	2030

Source: CEN



Outlook

Chile's planned transmission network expansion involves adding approximately 4,000 km of lines and over 6,000 MVA of substation capacity between 2022 and 2031 at voltage levels of 110kV and above. This includes ongoing, planned, and proposed projects (ReGlobal, 2022). The capacity plans must factor in the required levels necessary to support the upcoming renewable power generation investments. There are signs that the lag in transmission capacity is fueling a decoupling in the power market prices across geographies. Some renewable-focused companies are facing insolvency as a result (C&P, 2024).

The timeliness of the transmission project pipeline may need urgent attention. The projects are beset with persistent execution challenges and recurring delays. One key example is the \$1.48 billion Kimal-Lo Aguirre line (Conexión Energía), Chile's first HVDC project. It was intended to unlock 3GW of renewable capacity by 2029. It underwent multiple delays, setting a troubling precedent. Other projects are frequently stuck in procedural clearances. In April 2024, the environmental evaluation agency (SEA) rejected the permit for Celeo Redes' \$324 million Itahue-Hualqui transmission project (Gas Outlook, 2024).

To drive the growth of Chile's transmission network, accelerated project development and stronger regulatory incentives are critical. There might be a case for policy intervention in the transmission planning and implementation process. Such a shift could help bring a much-needed push for a rapid grid network rollout (BN Americas, 2023).



BRAZIL

Brazil's legacy hydropower-led power generation mix has been useful in maintaining a low-emission profile. Over time, the policy priority has shifted to renewable energy to reduce dependence on hydro and accelerate the decarbonisation of the power sector. The grid infrastructure is thus catching up. Renewable power projects, primarily in wind and solar, are progressively placing huge demands on the existing transmission network. The auctions for transmission contracts in recent years promise significant capacity augmentation for the major chokepoints in renewable-rich locations.



GDP
(Current Prices, \$ 2023)

2,174 Bn

Projected Average GDP
Growth 2024-28

2.5%

10-Year Govt. Bond Yield
(12-Month Rolling Average)

11.7%

Country
Credit Rating

BB

Renewable Energy
Share

29%

Total Transmission Line
Length (Km)

184,000

Note: Renewable Energy Share excludes hydropower



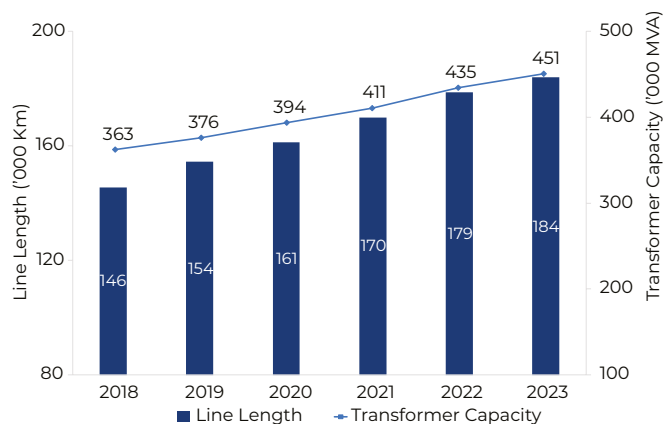
Transmission Network

The Brazilian power system comprises four interconnected regional subsystems: South, Southeast-Midwest, North, and Northeast. These regional subsystems constitute 98% of the power market. The remaining part comprises isolated power systems in regions including Amazonas, Roraima, Acre, Amapá, Rondônia, and part of Pará (ReGlobal, 2024). Multiple privately owned transmission companies manage and operate the network based on the respective concession contract terms. Eletrobrás and ISA CTEEP (Companhia de Transmissão de Energia Elétrica Paulista) are among the predominant transmission utilities. There is significant foreign investment in the industry. A notable one is that of the Chinese transmission system operator, State Grid Corporation, which operates major high-voltage direct current (HVDC) network segments in the Brazilian power system.

Over three-quarters of the transmission line length is concentrated at voltage ratings of 230kV and 500kV. A major area of focus is the long-distance HVDC-based transmission segments to enable the offtake from the remotely located renewable-rich locations. The auction-based independent transmission model has helped drive the investments. During the period 2018-2023, the line length grew at a compound annual growth rate (CAGR) of 4.4%. The pipeline continues to grow, with several HVDC lines in the works.

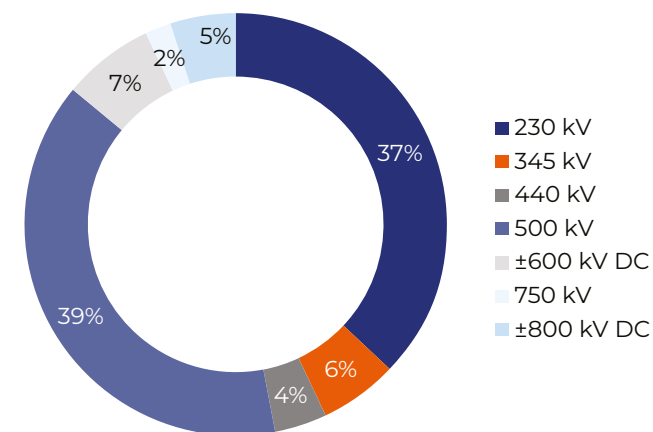
Cross-border power trade has yet to gain any important share in the country's power system. Most of the transactions are presently with Argentina. In December 2023, the country restored the power trade with Venezuela after a four-year break (Reuters, 2023). In October 2024, Brazil's Ministry of Energy and Mines published guidelines on importing power from Paraguay and also authorised four entities to enter into contracts in this regard. It was in follow-up to a memorandum of understanding signed between the two countries earlier in the year. (America Economia, 2024).

Transmission Network Growth



Note: Data for 2023 is as of November
Source: REGlobal

Classification of Transmission Voltage Levels



Source: REGlobal



Cross-border Transmission Links

Country Linkage	About the Linkage
Brazil-Paraguay	With an installed capacity of 14GW, the Itaipu Hydroelectric Dam is operated by Itaipu Binacional on the Brazil-Paraguay border. It meets the energy demands of both countries, with 90% serving Brazil.
Brazil-Argentina	The Garabi HVDC converter station enables power exchange between Brazil and Argentina, interconnecting their asynchronous grids (50 Hz in Argentina and 60 Hz in Brazil) with a transmission capacity of up to 2,200 MW.
Brazil-Uruguay (Two links)	The Rivera HVDC back-to-back station facilitates energy exchange between Brazil and Uruguay, converting frequencies between the two countries' grids with a transmission rate of 70MW. Established in 2016 with a 50/60 Hz back-to-back frequency converter in Melo, Uruguay. Situated northeast of Uruguay, the converter facility will allow Uruguay to trade energy with Brazil, increasing the flexibility and reliability of grid networks in both countries.
Brazil-Venezuela	A cross-border link from Venezuela's Guri hydropower complex supplies electricity to Boa Vista in Brazil, integrating the northern Brazilian region with Venezuela's power grid.

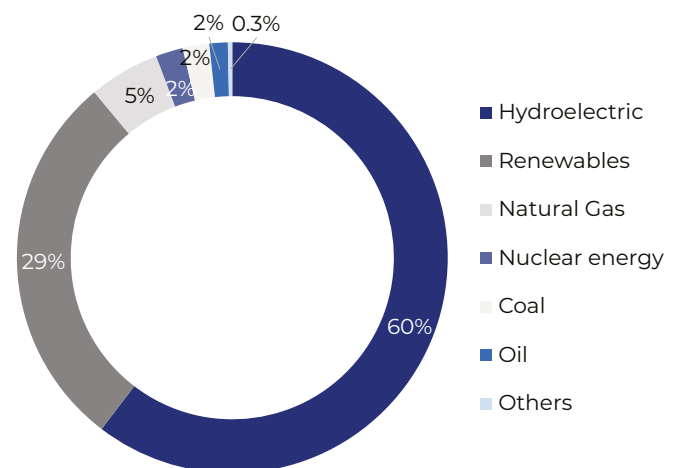
Source: GE, Hitachi Energy, Power Technology and Government of Brazil

Drivers in Energy Transition

Brazil's overarching policy targets on emission control set the agenda for energy transition in power, among other economic sectors. In November 2023, the Brazilian government signed a global agreement to triple renewable energy capacity by 2030 (Reuters, 2023). The commitment can be seen extending to the recent policy goal and commitment to reduce emissions by 59% - 67% by 2035, compared to the 2005 levels (WRI, 2024). Power sector decarbonisation will be among the key routes to achieve the targeted emission reduction.

The country's generation mix is skewed in favour of clean or low-carbon energy resources – over 90% of the grid-connected supply is based on hydropower, renewable energy and nuclear energy. With such a base, the country is already ahead of several G20 countries in clean energy-based power (including large-scale hydropower). A notable aspect is the rising importance of

Power Generation Mix



Source: Energy Institute



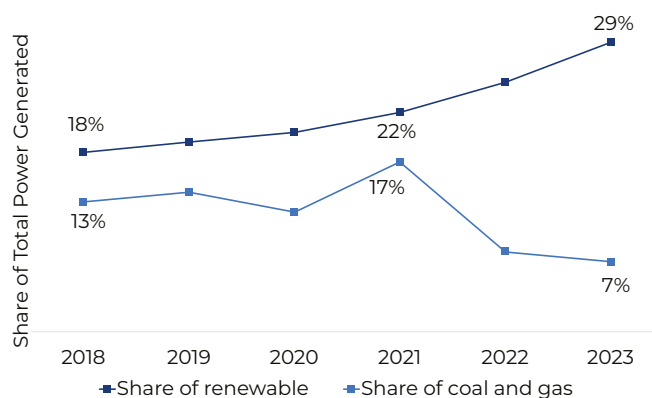
renewable energy (wind and solar) vis-à-vis hydropower, the latter being subject to drastic fluctuations from drought or poor rainfall conditions. The capacity addition rate illustrates this. During 2018-2023, renewable power capacities grew at a CAGR of 7.3%. Hydropower capacities grew at just 1% during the same period (IRENA, 2024).

The acceleration in renewable power capacity brought the typical challenges of grid integration. Lately, the grid operator has been imposing curtailment of wind and solar power generation. About 3% of the power thus generated was curtailed as of July 2024. The grid operator took to curtailment as a grid management measure since August 2023, when a power outage in the northern region spread to most of the country (Reuters, 2024). Apparently, the rise in wind and solar power capacity in the northeast region overwhelmed the transmission network. The curtailment of generation has not only impacted the viability of investments but also skewed the power market prices. It is likely to be mitigated with some of the vital transmission links in the pipeline aimed at connecting the populous demand centres with the renewable generation hotspots.

The grid constraints could intensify until the required transmission capacity is in place. Conventional fuel-based power, often positioned in grid-balancing roles, is scaling down in tandem with the rise in renewable energy penetration. The share of coal in the power generation mix reached 2% by the end of 2023 and may exit the power system much earlier than the targeted year of 2040. A similar declining trend is displayed by gas-based power generation. Relatively better hydropower reservoirs and the corresponding high generation during 2022 and 2023 held down the share of gas-fired power. However, these roles change rapidly. In 2021, gas-based power generation helped bridge the gap created by low hydropower generation. The same is playing out in 2024 as the depleted hydropower reservoirs are being compensated for with gas imports for power generation (Energy News,

2024). It may, thus, take some time before the power system is able to completely phase out gas from its generation mix.

Transition in Grid-Connected Power Generation



Source: Energy Institute



Policy and Regulation

Brazil's electricity transmission sector has effectively attracted private investment through a well-structured regulatory framework. The Ministry of Mines and Energy (MME) and the Agência Nacional de Energia Elétrica (ANEEL) oversee public auctions for transmission projects, granting concessions to private entities. These auctions have fostered a competitive environment, leading to significant private-sector participation. Notably, over the past two decades, approximately 250 companies have engaged in 350 Independent Power Transmission (IPT) projects, indicating a robust and dynamic market (International Trade Administration, 2023) (IEA, n.d.).

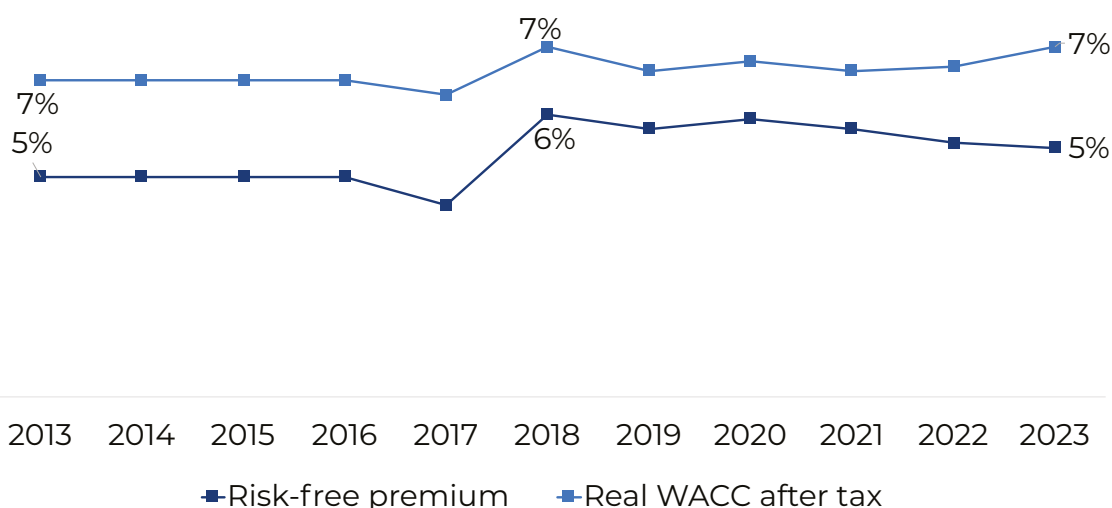
A key component of this framework is the regulated Weighted Average Cost of Capital (WACC), periodically adjusted by the regulator to reflect macroeconomic conditions. This approach provides investors with predictable returns, reducing perceived risks and enhancing investment appeal. The IPT model, in particular, sets revenue caps based on competitive auction outcomes, incentivising efficiency and cost-effectiveness. The success of this

model is evident in the consistent negotiation of auctioned lots post-2017, demonstrating sustained investor confidence.

Additionally, the Brazilian Development Bank (BNDES) has played a pivotal role in mobilising private capital. While its share in financing transmission and distribution projects has declined, indicating a maturing market, BNDES continues to support significant initiatives. For instance, in 2022, it financed Neoenergia with US\$270 million in funding for a 1,100 km transmission line, marking the country's first certified Green Loan (IEA, n.d.).

The rising trend in WACC between 2013 and 2023 reflects changes in investor return expectations and potential adjustments in the regulatory framework. The divergence between the WACC and the risk-free premium indicated a balance between regulatory interventions and market dynamics, highlighting the effectiveness of Brazil's regulatory mechanisms in maintaining investment appeal in the transmission sector while managing systemic risks (IEA, n.d.).

Regulated WACC and Risk-free Premium in Transmission



Source: IEA



Market Opportunity

The roadmap for expanding the power transmission network capacity is outlined in the government-commissioned publication titled “Plano Decenal de Expansão de Energia 2032” (PDE). It seeks a strategic approach to modernising the grid while augmenting the capacity for the upcoming generation units. Distributed Generation holds the largest share of the upcoming power generation capacity in Brazil. The transmission network must effectively integrate renewable and decentralised energy resources.

Investment commitments point to a rise in spending relative to historical levels. Between 2020 and 2023, transmission network spending declined from \$5.7 billion to \$3.5 billion. The projections for 2024-2026 suggest a recovery in the spending levels (BNEF, 2024), presenting an optimistic picture of the emerging network requirements. Some of the critical capacity gaps lie in connecting the wind and solar power of the northeastern region with the load centres of the southeastern region.

Estimated Transmission Grid Spend

Spend (\$ billion, real 2023)	
2024	3.4
2025	4.6
2026	5.1

Note: Data of 2024 is as of September 2024

Source: CFE

The auction-based tenders have been stepped up to attract the needed market players to the network buildout. In 2022, two transmission auctions raised \$3.8 billion for onshore wind connectivity. The largest transmission auction so far (as of June 2024) was concluded in 2023, involving \$21.7 billion in investment, predominantly led by the Chinese utility State Grid Corporation for an HVDC system. Among other recent major contracts, there was Engie Brasil's BRL2.9 billion concession contract awarded in September 2024 for transmission projects across five states. With the rapid auction contracts, the transmission pipeline can be expected to rise exponentially over the next 5-10 years.

Transmission Projects under Development

Project	Voltage	Length	Cost (USD million)	Scheduled Completion
500 kV Buritizeiro 3–São Gotardo do Pará 2 C1, 500 kV Pirapora 2–Buritizeiro 3 C1 and C2 lines; 500 kV Jaguará–Estreito C2 line; 500 kV Presidente Juscelino–Vespasiano 2 C1 and C2 lines; 500 kV Itabirito 2–Santos Dumont 2 and associated transmission network project	500/345 kV AC	1,083.8 km (500 kV–961.2 km; and 345 kV–122.6 km)	713.30	2027
500 kV Arinos 2–Paracatu 4, C1 and C2 lines; 500 kV Paracatu 4–Nova Ponte 3, C1 and C2 lines; 500 kV Nova Ponte 3–Araraquara 2, C1 and C2 lines; 440 kV Araraquara 2–Araraquara line and associated transmission network project	500/440 kV AC	1,707 km (500 kV–1,696 km and 440 kV–11 km)	956.69	2027



500 kV Morro do Chapéu II–Poçoões III C1 line and associated transmission network project	500 kV and 230 kV AC	1,031 km (500 kV–971 km; 230 kV–60 km)	462.75	2026
500 kV Quixadá–Crateús C1; Crateús–Teresina IV C1; Teresina IV–Graça Aranha C1; Boa Esperança–Graça Aranha C1; Curral Novo do Piauí II–São João do Piauí II, C1; São João do Piauí–Ribeiro Gonçalves, C3; Ribeiro Gonçalves–Colinas, C3; Morada Nova–Pacatuba, C1 lines and associated network project	500 kV AC	1,901	NA	2029/30
500 kV Bom Nome II-Zebu III, C1; Garanhuns II-Messias, C1; João Pessoa II-Pau Ferro, C1; Ceará Mirim II-João Pessoa II C1; Bom Nome II-Campo Formoso II C1, Zebu III-Olindina C1 lines and associated network project	500 kV AC	1,113	NA	2029/30
500 kV Juazeiro III-Campo Formoso II C1 line; Campo Formoso II-Barra II C1 line; 500 kV Buritirama-Barra II C1 line; 500 kV Barra II-Correntina C1 line; 500 kV Correntina-Arinos 2 C1 and associated network project	500 kV AC	1,116	612.73	2028/29
500 kV Gentio do Ouro II-Bom Jesus da Lapa II C2 and C3 lines; 500 kV Bom Jesus da Lapa II-Jaíba C1 and C2 lines; and 500 kV Jaíba-Buritizeiro 3 C1 and C2 lines projects	500 kV AC	1,610	841.97	2028/29
500 kV Morro do Chapéu II–Poçoões III; 500 kV Poçoões III- Medeiros Neto II; 500 kV Medeiros Neto II-João Neiva 2; and 500 kV João Neiva 2-Viana 2 lines project	500 kV AC	1,006	520.49	2028
±800 kV Graça Aranha-Silvânia DC transmission line; 500 kV Presidente Dutra-Graça Aranha C3 line, and associated transmission network project	±800/500 kV HVDC	1,517 km (±800 kV–1,468 km and 500 kV–49 km)	3,081.10	2029/30
500 kV Ourolândia II-Jussiape C1 and C2 lines; 500 kV Jussiape- São João do Paraíso C1 and C2 lines; 500 kV São João do Paraíso Capelinha 3 C1 line; 500 kV São João do Paraíso-Padre Paraíso 2 C1 line; 500 kV Capelinha 3-Itabira 5 C1 line; 500 kV Padre Paraíso 2-Mutum C1 line; and 500 kV São João do Paraíso substation project	500 kV AC	2,090	NA	2030

Source: REGlobal



Outlook

The projections in the PDE point to a requirement for 41,460 km of new transmission build by 2032. Almost 70% of them are at 500kV or above in voltage ratings due to the need for long-distance and efficient connectivity of renewable power projects. PDE's network expansion projections amount to BRL158 billion in investment, covering both near-term and long-term infrastructure demand.

Persistent curtailments can dissuade investors from commitments. There are already some signs in this regard, as operational projects face losses. Without mitigating steps, the transmission capacity constraint could aggravate the industry's problems. Grid reinforcements, upgrades, and technology enhancements are some of the key areas for short-run implementation alongside the priority longer-term projects.

The 24-year old Brazil-Argentina HVDC link, for instance, was contracted for an asset upgrade in September 2023 to enable better availability and reliability in the cross-border power transactions (Hitachi, 2023). Similarly, the transmission utility Eletrobras contracted Siemens for a \$200 million grid upgrade project for completion by 2026 (Reuters, 2023). Many more such projects might be needed to ensure readiness for the rapidly growing infrastructure demand. Grid-scale energy storage and policy interventions to expedite grid reinforcement / expansion projects in certain regions are among the other proactive measures to help sustain the growth momentum.

The transformation of the Brazilian power system, in keeping with the integration of renewable energy, will necessarily be a gradual transitory phase. The capacity, however, must be available in time for the huge investments in renewable energy generation in the grid.





08

About CleanBridge

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Sustainable Energy



Climate Finance



Sustainable Living



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