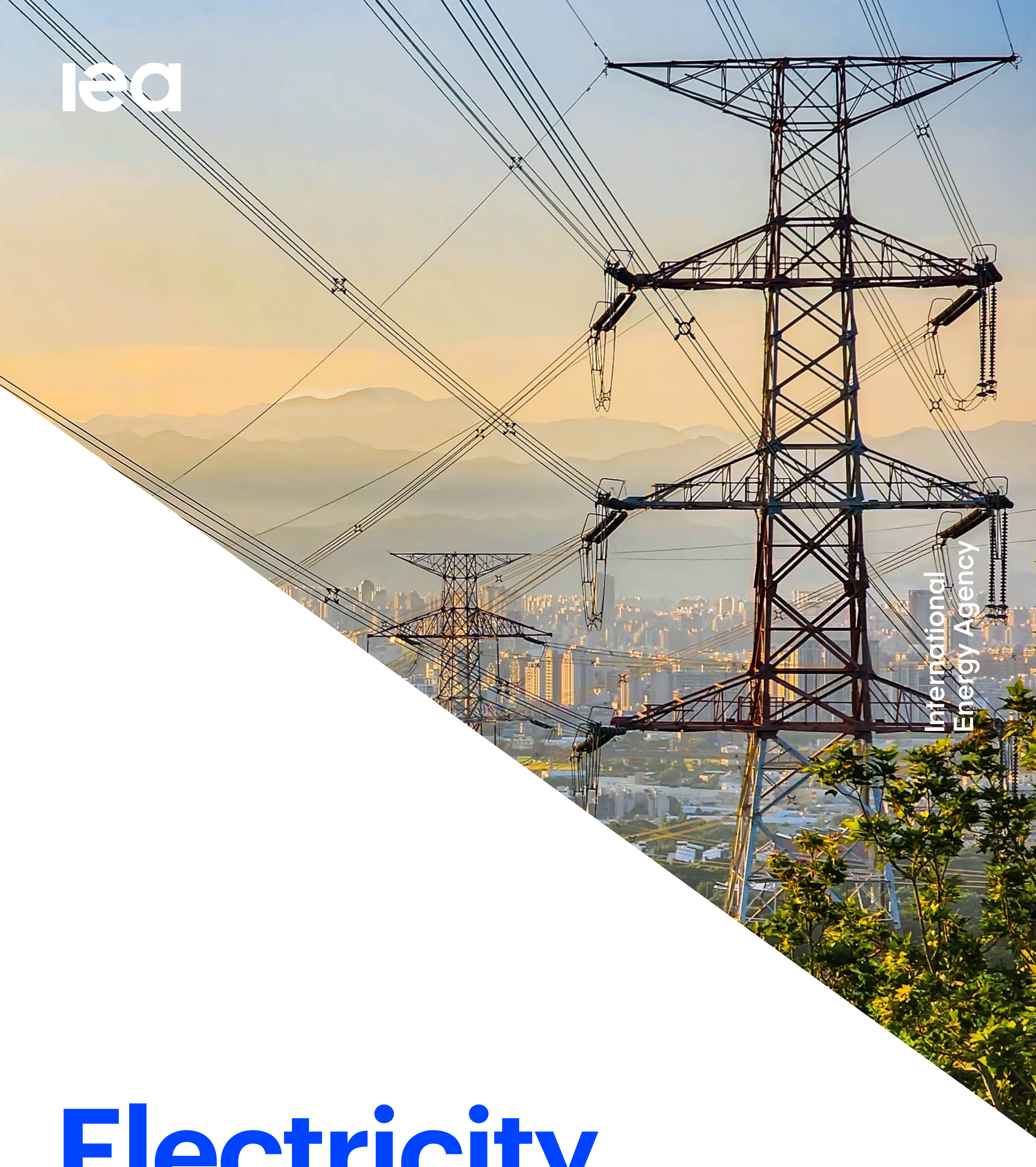


Electricity
2026

Analysis and forecast to 2030

INTERNATIONAL ENERGY AGENCY

The IEA examines the full spectrum of energy issues including oil, gas and coal supply and demand, renewable energy technologies, electricity markets, energy efficiency, access to energy, demand side management and much more. Through its work, the IEA advocates policies that will enhance the reliability, affordability and sustainability of energy in its 32 Member countries, 13 Association countries and beyond.

IEA Member countries:

Australia
Austria
Belgium
Canada
Czech Republic
Denmark
Estonia
Finland
France
Germany
Greece
Hungary
Ireland
Italy
Japan
Korea
Latvia
Lithuania
Luxembourg
Mexico
Netherlands
New Zealand
Norway
Poland
Portugal
Slovak Republic
Spain
Sweden
Switzerland
Republic of Türkiye
United Kingdom
United States

The European Commission also participates in the work of the IEA

IEA Association countries:

Argentina
Brazil
China
Egypt
India
Indonesia
Kenya
Morocco
Senegal
Singapore
South Africa
Thailand
Ukraine

Source: IEA.
International Energy Agency
Website: www.iea.org

Abstract

Global power demand growth continues to rise rapidly as the Age of Electricity gathers pace, supported by the increasing electrification of industry, transportation, and the buildings sectors. Growing consumption is also coming from some of the most dynamic segments of global economies, such as artificial intelligence (AI), data centres, and evolving technological innovations.

Against this backdrop, *Electricity 2026* – the IEA's annual report on global electricity systems and markets – provides in-depth analysis of the recent trends and policy developments underpinning this new era. It includes forecasts for electricity demand, supply and carbon dioxide (CO_2) emissions for select countries, by region and worldwide. This year the forecast period has been expanded to five years, 2026-2030, compared with the previous three-year outlook.

As electricity use grows, power systems will need greater flexibility to securely and cost-effectively integrate an increasingly diverse mix of electricity generation sources while accommodating evolving demand patterns and technologies. This year's report has a special focus on these challenges with chapters on grids and flexibility. It also includes detailed updates on demand response and utility-scale battery developments.

Acknowledgements, contributors and credits

This study was prepared by the Electricity Systems and Markets (ESM) Division of the International Energy Agency's (IEA) Directorate of Energy Markets and Security (EMS). The study was designed and directed by Eren Çam, Energy Analyst for Electricity, who also co-ordinated the production of the report.

The lead authors of the report were Eren Çam, Marc Casanovas, John Moloney, and Matthew Davis. Other IEA colleagues provided important contributions, including Javier Jorquera Copier, Chaerin Kim and Jacques Warichet.

The work greatly benefitted from strategic guidance from Keisuke Sadamori, Director of EMS and Maria Sicilia, Head of ESM. Valuable comments and guidance were provided by other senior management within the IEA, in particular, Laura Cozzi and Tim Gould. In addition, expert guidance and valuable input from Carlos Fernández Álvarez, Senior Energy Analyst, is greatly appreciated. The work benefitted from the guidance and input from Dennis Hesseling, Head of Gas and Coal Markets Division.

The report also benefited from analysis and data from Nadim Abdillama, Jenny Birkeland, Esra Bozkır Broekman, Gyuri Cho, Johanna Dahl, Celeste Del Vecchio, Carole Etienne, Adrian Gao, Grace Henry, Lydia Jayakumar, Javier Jorquera, Natalie Kauf, Yu Kawasaki, Jinil Kim, Ja Hyun Kim, Claire Lesieur, Augustin Lorne, Akos Losz, Rita Madeira, Edward McDonald, Gergely Molnar, Pedro Nino de Carvalho, Ranya Oualid, Camille Paillard, Isaac Portugal, Frederick Ritter, Stephan Terhorst, Ottavia Valentini, Matthew Van Der Beeuren, Peerapat Vithayasrichareon, and Hasti Wiandita.

IEA colleagues across the agency provided valuable input, comments and feedback, in particular, Heymi Bahar, Stéphanie Bouckaert, Federico Callioni, Dan Dorner, Michael Drtil, Araceli Fernandez Pales, Paolo Frankl, Pablo Hevia-Koch, Martin Küppers, Rebecca McKimm, Tetsuya Mizuno, Apostolos Petropoulos, Zubin Postwalla, Brendan Reidenbach, Max Schönfisch, Anthony Vautrin and Brent Wanner.

The authors would also like to thank Diane Munro for skilfully editing the manuscript and the IEA Communication and Digital Office, in particular, Jethro Mullen, Oliver Joy, Isabelle Nonain-Semelin and Astrid Dumond. We also thank Einar Einarsson for his assistance in setting up the peer review.

Many experts from outside of the IEA reviewed the report and provided valuable comments. They include: Michel Augonnet (CIGRE), Edith Bayer (Oregon Department of Energy), Soukaina Boudoudouh (IRESEN), Salma Boumhaouad (IRESEN), Marco Baroni (Baroni Energy Consulting), Jesse Burton (E3G/ESRG, UCT), Samir Chandra Saxena (POSOCO), Peter Claes (Febeliec), Bram Claeys (RAP), Norberto Cuenca (Enel Green Power), Ganesh Doluweera (CER), Fernando Dominguez (EU DSO Entity), Keith Everhart (Secretariat Economists), Peter Fraser (PeterLFConsulting), Kerry Galloway (AEMO), Paul Giesbertz (EP NL), Michael Grubb (UCL), Xue Han (IREP), Donghoon Kim (SKI), Francisco Laverón (Iberdrola), Xiaomeng Lei (CEC), Rannveig Loken (CIGRE), Christoph Maurer (Consentec), Tatiana Mitrova (Columbia University), Noor Miza Razali (Tenaga Nasional Berhad), Victoria Mollard (AEMC), Emmanuel Neau (EDF), Mika Ohbayashi (Renewable Energy Institute), Jonatan Olsen (Danish Energy Agency), Lars Stephan (Fluence), Eli Pack (AEMO), Yannick Phulpin (EDF), Marcio Szechtman (CIGRE), Andreas Ulbig (RWTH Aachen University), Arjon Valencia (IEMOP), Matthew Wittenstein (ESCAP), Jingjie Zhang (CEC) and Romain Zissler (Renewable Energy Institute).

Table of contents

Executive Summary

Electricity demand is set to grow strongly through 2030 as the Age of Electricity takes hold

Global electricity demand is forecast to increase at a brisk average annual rate of 3.6% over the 2026-2030 forecast period, supported by rising consumption from industry, electric vehicles, air conditioning and data centres. Worldwide electricity demand grew by 3% year-on-year in 2025. This followed growth of 4.4% in 2024, when intense heat waves and strong industrial activity in many regions boosted electricity use. Looking ahead, annual demand growth over the next five years is set to be 50% higher on average compared with the average across the previous decade.

For the first time in three decades, excluding periods of crisis-related disruption, global electricity demand outpaced economic growth in 2024 in what is set to become a broader trend in the coming years. Despite a slight reversal in 2025 due to weather conditions that affected electricity demand, a fundamental shift in the longstanding relationship between electricity demand and economic activity is set to be a defining feature of the forecast period. Through 2030, electricity consumption is projected to grow at least 2.5 times as fast as overall energy demand.

Emerging economies continue to be the main pillar of demand growth, accounting for nearly 80% of additional electricity consumption through 2030. While India and Southeast Asia are increasingly set to drive rising energy demand over the coming decade, China is forecast to remain the single largest contributor to global electricity demand growth through 2030, accounting for close to 50% of the increase. Over the next five years, China alone is expected to add demand equivalent to the total electricity consumption of the European Union (EU) today, with average growth of 4.9% annually. This is close to its 2025 pace of 5% but slower than its 6.5% average over the past decade. India and Southeast Asia's share of electricity demand growth among emerging economies is forecast to rise substantially by 2030, driven by robust economic growth and rapidly rising demand for air conditioning, which is set to boost both annual consumption and peak loads.

Electricity demand growth in advanced economies is accelerating again after 15 years of stagnation. This resurgence signals a new era in which electricity is a major energy input to some of the most dynamic drivers of global economies, such as artificial intelligence (AI), data centres and advanced manufacturing. In 2025, advanced economies accounted for almost 20% of global electricity demand growth, up from 17% in 2024. We expect this share to remain near the 20% level on average over the forecast period, driven by expanding industrial activity and the continued growth of data centres, electric vehicles and other end-uses of electricity. In the United States, electricity demand rose by 2.1% in 2025 and is projected to grow by nearly 2% annually through 2030, with around half of the total increase driven by the rapid expansion of data centres. After rising by less than 1% in 2025, electricity demand in the European Union is expected to grow more strongly. Assuming a moderate rebound in industrial activity, EU demand is forecast to increase by around 2% per year through 2030 – although consumption is not expected to return to 2021 levels before 2028. Many other advanced economies – such as Australia, Canada, Japan and Korea – are also expected to see faster electricity demand growth through 2030.

Half of the world's electricity is forecast to come from renewables and nuclear by 2030

Total generation from renewables is overtaking coal, in line with previous IEA forecasts. With solar PV generating record amounts of electricity, renewable output rose rapidly in 2025, virtually matching the level of coal-fired generation based on the latest available data. This was despite weaker hydropower output in some regions and lower-than-average wind speeds, particularly in Europe, which tempered overall growth in renewable generation. Renewable output is forecast to grow by about 1 000 terawatt-hours (TWh) annually through 2030, with solar PV alone accounting for over 600 TWh. In percentage terms, renewable generation is forecast to rise at an annual rate of 8% per year. Renewables and nuclear are together expected to account for around half of global electricity generation by 2030.

Nuclear generation set a new record in 2025 and is set to continue rising steadily through 2030. Nuclear power output in 2025 was supported by reactor restarts in Japan, higher generation in France, and new capacity additions in China, India and other countries. While most of the growth in nuclear generation through 2030 is expected to occur in emerging economies, with China alone accounting for around 40% of the global increase, nuclear energy is also regaining strategic importance in many advanced economies, underpinned by supportive policy frameworks to extend the lifetime of reactors and add new capacity.

Although coal generation is set to lose ground globally, it remains the single largest source of electricity in 2030

Globally, coal-fired generation remained broadly flat in 2025, but regional trends diverged in ways not seen in previous years. Coal use declined in India and China due to slower electricity demand growth and the rapid expansion of renewables, and it increased in the United States as higher natural gas prices compared with 2024 and a slowdown in the retirement of coal plants, supported by federal policy, prompted higher coal use in the power sector. In the European Union, record solar generation was partially offset by weak hydropower and wind output, limiting the overall decline in coal use.

Over the 2026-2030 period, renewables, natural gas and nuclear together are expected to meet all additional global electricity demand in aggregate. Complementing renewable and nuclear output, gas-fired generation is set to grow by an average of 2.6% per year through 2030 – similar to its growth rate in 2019 and significantly faster than the annual average of about 1.4% seen over the past five years. This growth is driven primarily by rising US electricity demand and fuel switching from oil to gas in the Middle East. Renewables, gas and nuclear together are expected to displace generation from coal, which is forecast to decline slightly and return to near its 2021 level by 2030. With coal-fired output in China expected to decline slightly, increases in India, Southeast Asia and other regions are forecast to be more than offset by declines in Europe and the Americas. Taken together, renewables are set to contribute the highest share of global electricity generation by 2030, though coal will remain the single largest fuel source for power generation.

Rapidly evolving power systems are bringing grids and flexibility to the forefront of policymaking

The Age of Electricity requires a fast and efficient expansion of grids and system flexibility to securely and cost-effectively integrate a changing mix of generation, demand and storage. Variable output from solar PV and wind continues to expand quickly, with their share of global generation set to rise from 17% today to 27% by 2030. Meanwhile, newer sources of demand – such as electric vehicles, heat pumps and highly concentrated loads, such as data centres – are expected to grow rapidly. At the same time, more than 2 500 gigawatts (GW) worth of projects – encompassing renewables, storage, and projects with large loads, such as data centres − remain stalled in grid connection queues worldwide. Since grid investment has lagged well behind investment in generation capacity, many power systems are already experiencing rising congestion-related curtailment. Meeting forecasted electricity demand through 2030 would require annual grid investment to increase by roughly 50% by 2030 from today's USD 400 billion, alongside a significant scaling up of grid-related supply chains. At the same time, grids built for peak capacity often have substantial unused capacity during off-peak periods. As grids and flexibility rise up the policy agenda, making more efficient use of existing systems can help relieve congestion and accelerate integration while grid expansion efforts continue.

Complementary measures, such as grid-enhancing technologies and regulatory reforms, can also unlock significant near-term capacity while grid expansions advance. IEA analysis for this report shows that these measures together could free up enough capacity to connect around 1 200 GW to 1 600 GW of advanced-stage projects currently stuck in queues worldwide. About 750 GW to 900 GW of projects could be enabled via more flexible, non-firm grid connection agreements. These agreements typically allow faster grid access, with some limitations, and can create extra hosting capacity before grid upgrades are completed. Another 450 GW to 700 GW could be unlocked by deploying grid-enhancing technologies such as dynamic line rating and advanced power-flow control, as well as larger upgrades like reconductoring and voltage uprating. Realising this potential would require updates to regulatory frameworks and the timely deployment of technical solutions.

Utility-scale battery deployment is accelerating rapidly, becoming a significant source of short-term flexibility. While conventional power plants remain the primary source of power system flexibility, the growing fleet of large-scale batteries is playing a rising role in supporting security of supply. The strong growth is especially notable in regions with rapidly rising shares of solar PV and wind in electricity generation. Markets such as California, Germany, South Australia, Texas and the United Kingdom have all seen strong growth in utility-scale battery capacity in recent years. Battery costs continue to fall, enhancing their competitiveness, but efforts to reduce market barriers and address integration challenges can help unlock their full potential.

Global emissions from electricity generation are forecast to plateau through 2030

Global power sector emissions remained flat in 2025 and are forecast to plateau over the 2026-2030 period as renewables and nuclear account for a growing share of generation. Electricity generation remains the largest source of energy-related emissions, producing around 13 900 million tonnes of carbon dioxide (CO_2) annually. After increasing by an average of 1.4% per year between 2022 and 2024, CO_2 emissions from electricity generation stabilised in 2025. Compared with a decade earlier, the global CO_2 intensity of electricity was down by 14%, and it is set to decline more rapidly through 2030 as the share of low-emissions generation continues to rise.

Affordability and competitiveness take centre stage

Affordability remains a key concern, with household electricity prices in many countries rising faster than incomes since 2019. While energy- and supply-related components of electricity prices have eased from their crisis peaks, they remain well above 2019 levels. Non-energy components – such as network charges, taxes and other levies – continue to account for a large, and often growing, share of household bills. In addition, electricity is also taxed more heavily than natural gas in many countries, weakening incentives for households to electrify heating, cooking or hot water use. As a result, policymakers are increasingly focusing on policy frameworks, market designs and regulation to improve affordability and encourage electrification. Ensuring prices remain affordable while still reflecting costs and incentivising demand-side flexibility is emerging as a central challenge. More flexible and efficient use of existing infrastructure can help contain future system costs and deliver greater savings for consumers.

Electricity price gaps across regions persist, adding competitive pressures. Average wholesale electricity prices in 2025 rose year-on-year in several regions and countries, including in the European Union and the United States, reflecting higher natural gas prices. Meanwhile, prices fell in other countries, such as Australia and India. Competitive pressures are most acute for energy-intensive industries, with significant differences continuing to be observed across regions.

Safeguarding the security and resilience of power systems is a critical priority

Recent large-scale power outages worldwide underscore the importance of electricity security for modern economies and societies. Power systems face rising risks from ageing infrastructure, extreme weather events, cyberthreats and other emerging vulnerabilities. Blackouts in Chile, the Iberian Peninsula and Mexico in 2025 had widespread impacts. Recent incidents, such as the EstLink-2 cable outage between Finland and Estonia, the Heathrow substation fire and the Berlin arson attack, exposed critical vulnerabilities. Strengthening the physical protection of critical infrastructure and deploying advanced monitoring and early-detection systems will be essential to guard against threats. As electrification increases, ensuring reliable supply depends on strong grids, resilient supply chains and diverse flexibility resources. Meeting evolving system needs also requires modernised operational frameworks, including updated grid codes, refined reserve requirements and adaptive regulatory structures.

Demand

The Age of Electricity has arrived, underpinned by strong demand growth

As the Age of Electricity moves apace, demand is on a solid upward trajectory in our five-year forecast period from 2026 to 2030. Amid robust growth, the next five years will add on average 50% more electricity demand per year than the annual average additions over the past decade. The brisk pace will be supported by growing industries, electric vehicles, space cooling, and data centres, among many other end uses. Electricity consumption is now projected to grow at least 2.5 times faster than overall energy demand, hastening the world's transition to an electricity-based economy. In tandem, the relationship between electricity demand and economic growth is undergoing a paradigm shift. Traditionally, electricity use has closely tracked economic expansion, excluding periods of global financial crises. However, in a marked departure from the past, electricity demand is now expected to outpace economic growth on a global scale through 2030.

While emerging economies continue to be the main pillars of growth in electricity use, demand in advanced economies is now rising again after a 15-year period of stagnation. The resurgence signals a new era in which electricity is a major energy input to some of the most dynamic drivers of global economies, such as artificial intelligence (AI), data centres, technological innovations, and the "electrification of everything". As a result, both total and per capita electricity consumption will reach new record highs in many regions of the world through 2030.

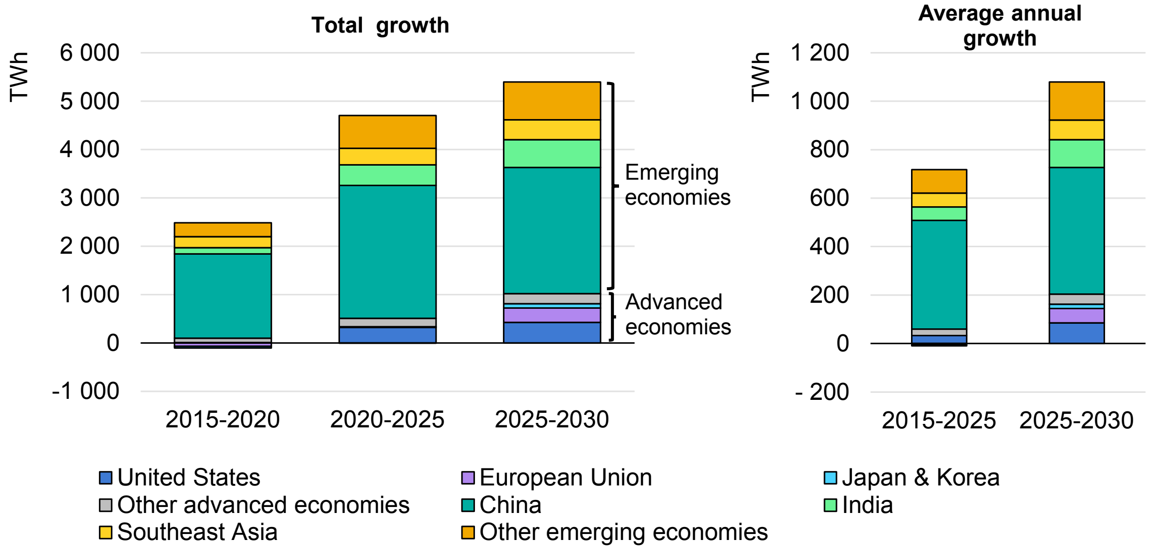
This chapter presents our global electricity demand forecast and a detailed overview of emerging trends in major economies, which highlight the urgent need for greater power system flexibility (see separate chapters on "Grids" and "Flexibility"). In addition, individual regions and countries are covered more in-depth in the Regional Focus chapter of our report.

Demand in advanced economies is rising after a long period of stagnation

Electricity demand in advanced economies is on an upward trajectory again after a 15-year period of stagnation. Flat or declining demand in many advanced economies reflected efficiency improvements across end-use sectors and industrial restructuring. Advanced economies saw overall electricity demand relatively static in 2015-2020 and their share of global growth rising only to 10%

in 2020-2025. The shift to growth became apparent in 2025, when advanced economies accounted for almost 20% of additional global demand, up from 17% in 2024. We expect this share to remain close to 20% through 2030, as electricity demand continues to grow due to a combination of increasing consumption from data centres, electric vehicles, air conditioners and heat pumps, among many other sectors.

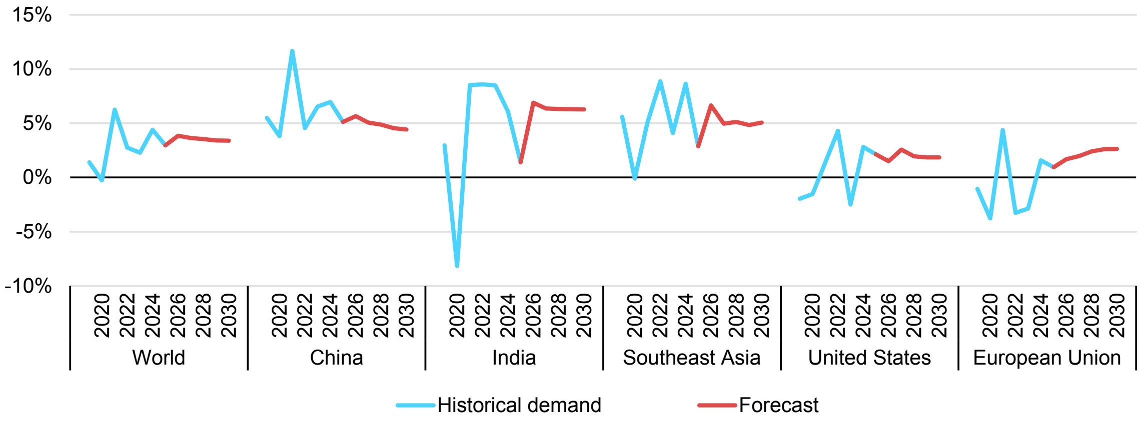
Global electricity demand growth by region, 2015-2030



Over the 2026-2030 outlook period, we expect electricity demand growth to gather pace across the advanced economies. Electricity consumption in the United States is set to rise by close to 2% on average per year – more than twice the rate of the past decade – with data centre expansions continuing to be a major driver. The European Union is forecast to see its electricity demand grow at an average annual rate of 2.3% out to 2030. However, we do not expect EU electricity demand to rise back to its 2021 level before 2028.

India and Southeast Asia are emerging as major engines of overall energy demand. However, in the electricity sector to 2030, the People's Republic of China (hereafter, "China") remains the dominant source of growth, accounting for nearly 50% of the global increase due to its much larger market size. Over the next five years, China alone is set to add electricity demand equivalent to the European Union's current consumption. Electricity demand growth in China is expected to moderate to an average of 4.9% annually over the 2026-2030 forecast period, down from the 6.5% average recorded over the previous decade. By contrast, India is expected to post an increase of 6.4% and Southeast Asia at 5.3%, an acceleration from the slower rates in 2025, based on expectations of continued robust economic growth and rising electrification.

Year-on-year percent change in electricity demand in selected regions, 2019-2030



Notes: Data for 2026-2030 are forecast values. The plots start from 2019, whereas the x-axis labels are shown only for the even years due to limited space.

Electricity consumption set to rise strongly across all sectors

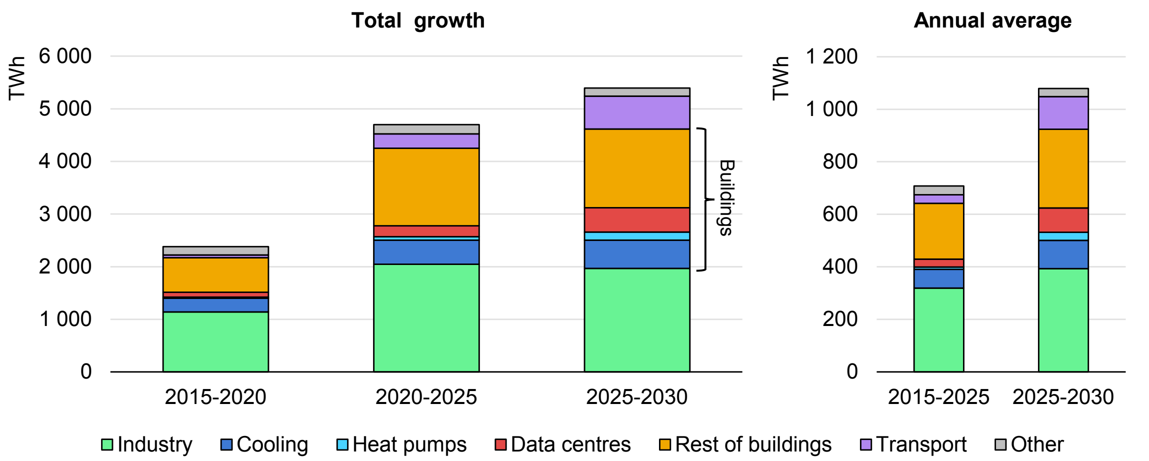
Global electricity demand increased year-on-year by 3% in 2025, following 4.4% in 2024. While intense heatwaves across many regions bolstered power use in 2024, comparably milder weather and weaker industrial and manufacturing activity in some regions tempered the overall pace in 2025. However, we expect demand growth to pick up in 2026-2030, to an average 3.6% over the next five years – a significant acceleration compared to the 2.8% annual rate of the past decade. This corresponds to adding on average approximately 1 100 TWh each year through 2030 globally – versus an average 700 TWh per year from 2015 to 2025. Global electricity consumption will reach 33 600 TWh in 2030, up from 28 200 TWh in 2025.

Many major electricity consuming countries and regions saw weaker demand growth in 2025 versus the year earlier, largely due to a slowdown in industry and manufacturing amid uncertain trade policies, combined with milder weather patterns compared to 2024. China and India experienced moderate growth of 5.1% and 1.4%, respectively. Southeast Asia also saw lower growth of around 3% y-o-y, down from a much higher 8.6% in 2024. Electricity demand growth in the United States eased marginally to 2.1% in 2025, from 2.8% the previous year. In the European Union, demand rose at the more modest pace of 0.9%, following a moderate recovery of 1.6% in 2024.

In 2025, approximately 58% of the increase in global electricity demand came from China, compared to 52% in 2024. Overall, emerging markets and developing economies (EMDEs), including China, accounted for about 80% of global growth in 2025, and are expected to maintain that share over the next five years. This compares with an average 95% in the past decade, reflecting an increasing contribution from advanced economies.

Over the forecast period, electricity demand is projected to post strong growth across all major consuming segments. The buildings sector – including residential and commercial – is expected to see the largest absolute growth, and contribute 49% to additional global demand between 2025 and 2030. Higher electricity use from space cooling, data centres and heat pumps make up almost half of the growth in the buildings sector worldwide out to 2030. Industrial electricity consumption is also expected to accelerate compared to the past decade, in particular from light industries. At the same time, fuelled by the rapid uptake of electric vehicles, transportation's share of demand growth is forecast to rise to more than 10%, double from the past five years. As the world's transition to an electricity-based economy is hastened, the share of electricity in total final consumption is set to increase from 21% in 2025 to 24% in 2030.

Global electricity demand growth by sector and end-use, 2015-2030

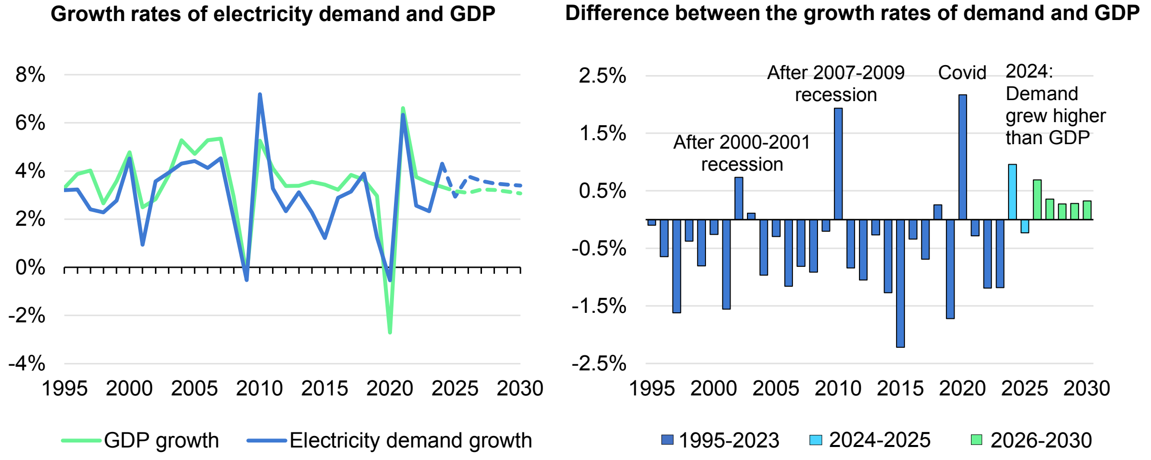


Electricity demand breaks with three-decade history, outpacing global economic growth

A trend shift in the link between electricity demand and economic growth is taking place on a global scale, amid strong demand increases from electricity-intensive industries, air conditioning (AC), data centres and continued electrification of end-use sectors. Over the past three decades, global electricity consumption has only grown significantly faster than the world economy during periods associated with economic shocks, such as the aftermath of the 2000-2001 recession, the 2008-

2009 financial crisis or during 2020 amid the pandemic. However, 2024 marked the first normal year when electricity demand grew much more rapidly than the economy. Although this trend saw a slight reversal in 2025 amid weather impacts, electricity demand growth is projected to eclipse the pace of GDP expansion throughout our forecast period.

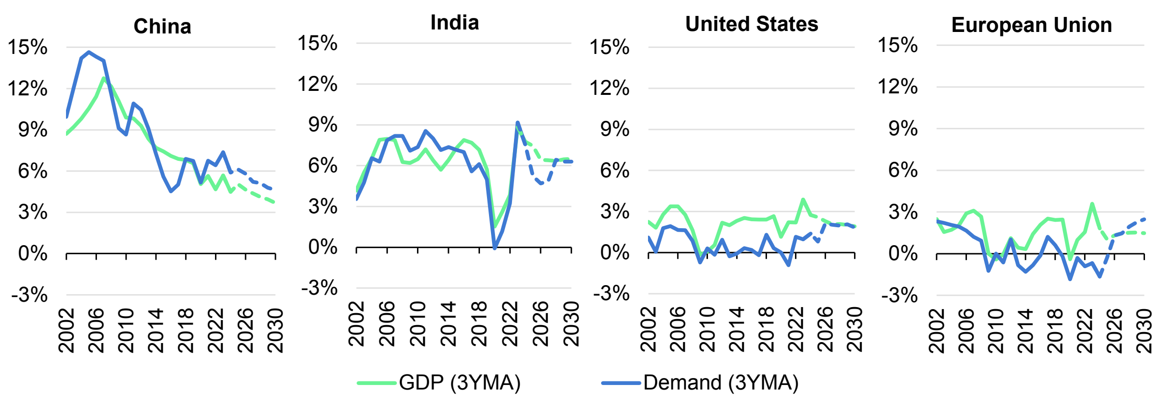
Global electricity demand and GDP trends, 1995-2030



Note: Data for 2026-2030 are forecast values. GDP is based on the IMF World Economic Outlook.

The shifting trend in electricity demand growth compared to the pace of economic growth can already be observed in a number of regions. China's electricity consumption has been growing faster than its economy since 2020. While electricity demand gains have traditionally been significantly lower than economic growth rates in the United States and the European Union, this is changing as the gap between electricity consumption and GDP begins to close.

Year-on-year percent change in electricity demand and GDP in selected regions, 2002-2030



Notes: Data for 2026-2030 are forecast values. 3YMA = three-year moving average. GDP is based on the IMF World Economic Outlook.

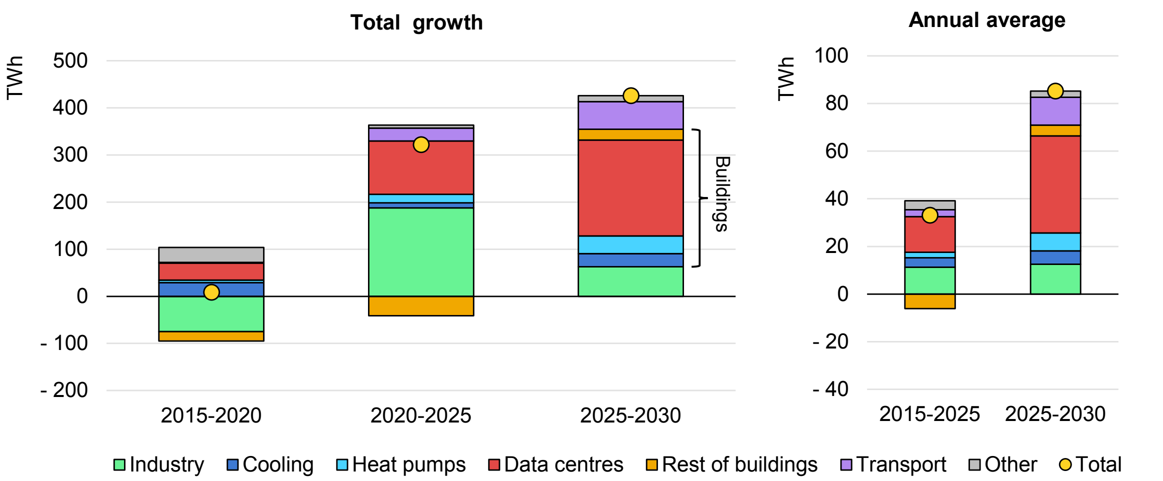
US and EU electricity demand forecast to post robust growth over 2026-2030

Electricity demand rose in both the United States and the European Union in 2024 and 2025, with continued strong growth forecast for 2026-2030. However, the sectoral composition of this growth and its underlying drivers differ between the two economies.

Electricity demand in the **United States** increased by 2.1% in 2025, following 2.8% growth in 2024, when hotter summer temperatures boosted consumption. In both years, the buildings sector – residential and commercial combined – accounted for over 70% of the country's demand growth. In 2025, in addition to strong economic activity and expanding data-centre loads, higher space-heating needs due to colder winter temperatures, with about 10% higher heating degree days (HDDs), also supported demand.

US electricity use is set to add more than 420 TWh in total over the next five years. The rapid expansion of data centres is expected to make up about 50% of demand growth out to 2030. The buildings sector excluding data centres will also remain a significant contributor to growth, largely due to rising consumption from space cooling and heat pumps. Growth from the industrial sector is expected to be another major driver, supported by reshoring and other new large loads such as semiconductor and battery manufacturing plants. The transport sector is also expected to contribute to demand growth with rising numbers of EVs.

Electricity demand growth by sector and end-use in the United States, 2015-2030

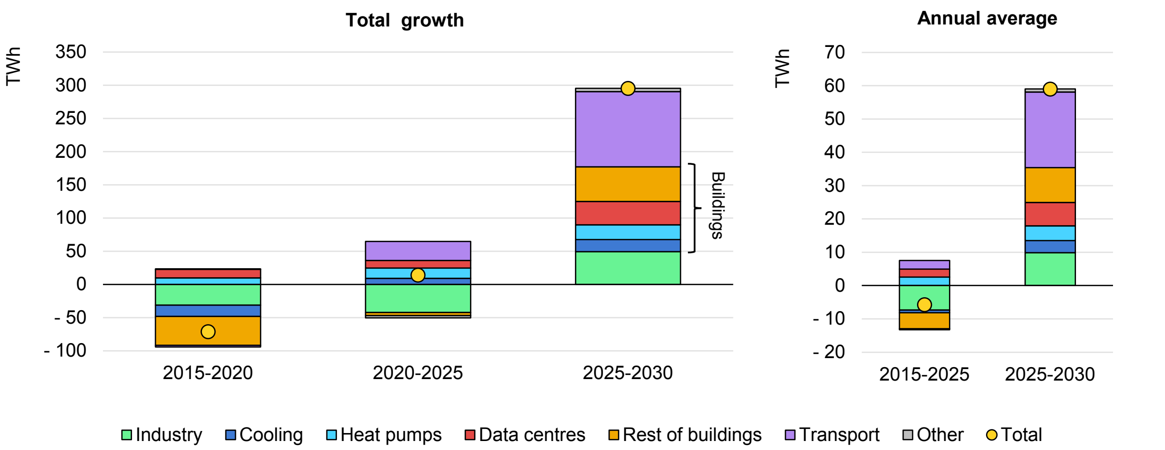


The **European Union**'s electricity consumption rose by an estimated 0.9% in 2025, following a 1.6% increase in 2024. Higher space-heating needs, due to a spike in colder winter temperatures in Q1 2025, combined with a sharp rise in AC use in the commercial and residential sectors, in the wake of record-breaking summer heatwaves, significantly boosted the region's electricity demand. The continued uptake of EVs and heat pumps were also key drivers of growth in 2025. A detailed analysis of the EU demand trends in 2025 can be found in the regional focus section of our report.

EU electricity demand is forecast to increase by about 300 TWh, over the next five years. This comes after two years of declines in 2022-2023 and modest recovery since then. Electricity consumption in the EU industrial sector fell by about 6% in both 2022 and 2023, driven by the production declines in the energy-intensive industries amid the energy crisis. Although the industrial sector's demand decline reversed in 2024, with a modest close to 2% increase, a meaningful recovery has yet to emerge, as we estimate demand remained broadly flat in 2025.

Assuming EU industrial demand recovers at a moderate pace over our outlook period, around 50 TWh of growth is forecast by 2030. The buildings sector is expected to be the main contributor to demand growth. While rising power use from data centres will provide a sizeable share, demand from cooling and heat pumps, as well as continued growth in the commercial sector, will account for most of the increase in the buildings sector. Transport follows closely behind, with EV adoption accelerating, adding more than 100 TWh to demand through 2030.

Electricity demand growth by sector and end-use in the European Union, 2015-2030

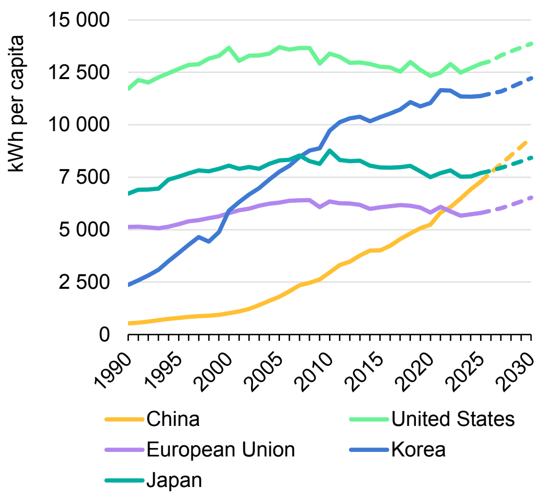


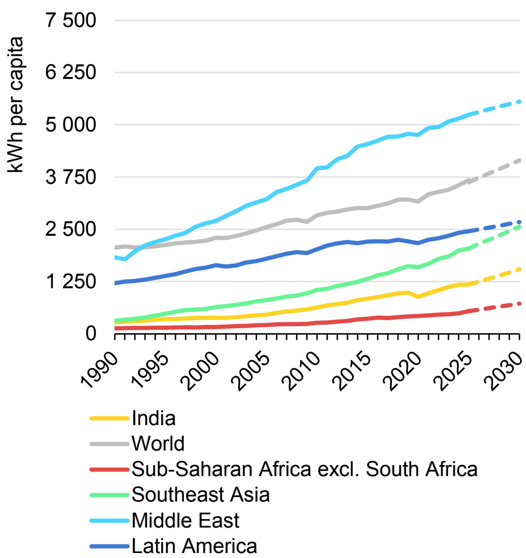
Per capita electricity consumption will reach new record highs in many regions

In line with rising demand, electricity consumption per capita is set to reach new highs in many regions. After growing until around 2009, electricity use per capita has been declining in many advanced economies since then, including the United States, the European Union and Japan. As demand growth accelerates over the coming years, we expect a reversal of this trend.

US electricity consumption per capita will reach a new high by 2030, surpassing its previous 2005 peak of 13 700 kWh/capita. Similarly, EU electricity consumption per capita is expected to exceed its previous high of 6 410 kWh/capita observed in 2008. Japan and Korea are also expected to see gradual per capita gains. Electricity consumption per capita in China eclipsed that in the European Union in 2022 and is forecast to continue rising steadily in 2026-2030. However, per capita electricity use of households in China is still below the average for EU households. Middle East per capita consumption has been steadily expanding over the past decades, as the region's economy grows and use of AC increases. While per capita consumption was below the global average roughly three decades ago, it is now almost as high as that of the European Union and will continue to increase further over our forecast period.

Electricity consumption per capita in selected countries and regions, 1990-2030





Note: Data for 2026-2030 are forecast values.

Electricity consumption per capita in Southeast Asia and India have been rising strongly over the past decade, with both regions doubling the rate since 2009.

However, Africa's progress is hindered by the slow growth of its access to energy supply. Over the past 30 years, electricity use per capita in sub-Saharan Africa has remained relatively flat, despite recent progress. Today, around 600 million people in the region still lack access to reliable electricity, significantly constraining economic development. Although reliable electricity is not the sole determinant of economic prosperity, its scarcity continues to impede progress across much of the region.

China's electricity demand is on a solid growth path through 2030

China's net electricity demand surpassed 9 500 TWh in 2025, up by 5.1% y-o-y. This is a slowdown compared to the previous two years, when demand grew by 6.6% in 2023 and 7.0% in 2024. While demand growth in buildings and transport remained strong, led mainly by increased AC use during summer heatwaves, and a growing fleet of EVs, global economic uncertainty, trade restrictions and a structural slowdown in domestic demand resulted in limited gains in China's industrial sector in 2025. Despite this, industry remains the major driver of growth in the country, which accounted for half of the total gains in electricity demand in the past five years.

We expect these trends to continue over the next five years, with electricity demand set to rise by an annual average 4.9%. While a slowdown compared to the 6.5% average observed over the 10-year 2016-2025 period in relative terms, in absolute terms, average annual demand growth rises from 450 TWh to 520 TWh. Out to 2030, China is expected to add about 2 600 TWh to electricity consumption, roughly equivalent to the current demand of the European Union.

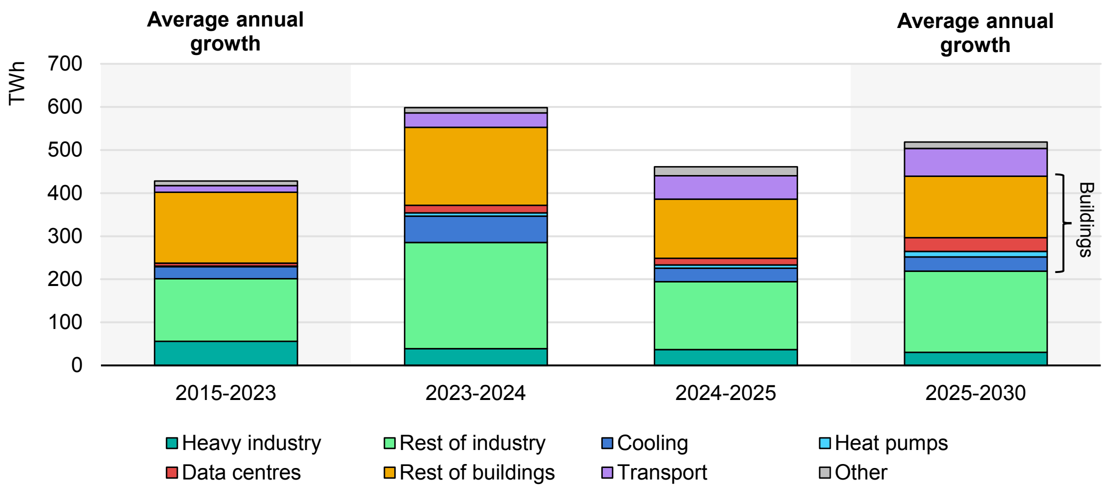
Industry leads China's demand growth, followed by the buildings and transport sectors

After rising at a moderate 3.7% y-o-y in H1 2025, electricity demand growth in China recovered in H2 2025 amid warmer summer and autumn temperatures, and a mild recovery in industrial growth. Nationwide, monthly consumption surpassed 1 000 TWh for the first time in July and then again in August. Demand in the industrial sector, responsible for around 60% of China's total demand, grew by 3.7% in 2025, 1.4 percentage points (pp) lower than the previous year. However, this was compensated for by strong demand growth in the services sector of 8.2% y-o-y, the residential sector of 6.3%, and road transport, where consumption at EV public charging stations grew by nearly 50%.The weather impact in 2025 on electricity demand was less pronounced on an annual basis, as the total number of cooling and heating degree days remained relatively unchanged compared with 2024. Demand in the ICT and digital services subsector, which includes data centres and 5G networks, increased by 17% y-o-y.

Over the five-year period from 2021 to 2025, the industrial sector (including the energy industry) contributed to about 50% of the increase in China's electricity demand, 4 percentage points (pp) lower than the previous five years. Most of the growth within the industry sector took place in non-heavy industries, particularly the machinery subsector, including the electricity-intensive manufacturing of solar PV modules and batteries, among others.

The contribution of industry to total demand growth has been decreasing over time, with the growing prominence of the tertiary sector within the economy, in addition to light industries, increasing their share in overall activity in China. In our 2026-2030 outlook, we expect the industries' share of electricity demand growth to decrease further, by 6 pp, as industrial growth rates stabilise between 3-4%, with electrification of processes, including heat pump deployment, and robust factory output as the main drivers.

Estimated drivers of change in electricity demand in China, 2015-2030

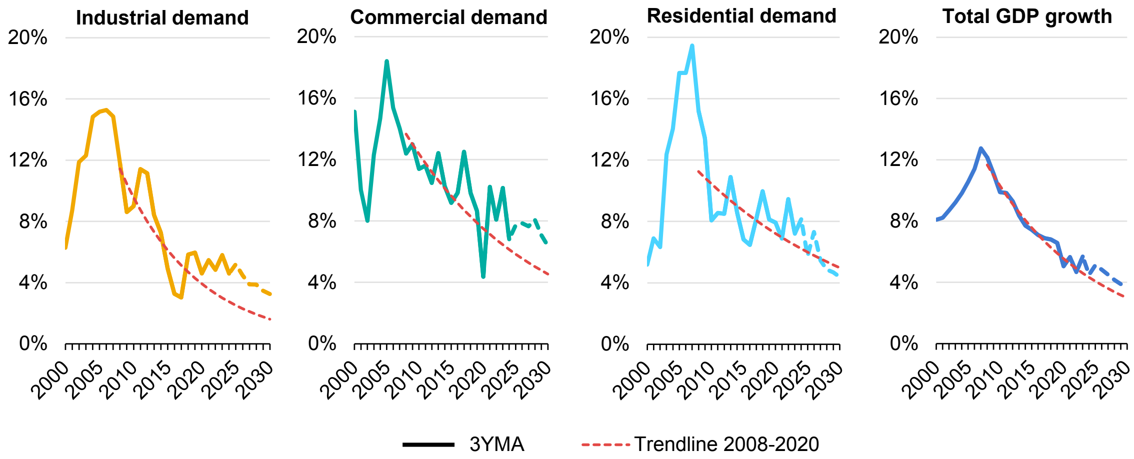


Notes: Buildings corresponds to residential and commercial sectors.
Sources: IEA analysis based on data from IEA World Energy Balances (2025), National Bureau of Statistics of China (2025).

The buildings sector accounted for another 41% of the demand growth in the 2021-2025 period, almost equally split between the commercial and residential segments. AC penetration in offices and households accounted for close to 17% of the growth within buildings, while the electrification and growing number of end-uses in the residential sector also contributed significantly. The development of services such as data centres and telecommunication networks resulted in this subsector providing more than 7% of the growth in buildings compared to 2020. Rising air conditioning use and expanding data centre activity are expected to make up an increasing share of buildings sector demand growth, with each contributing roughly 15% through 2030.

The transport sector has seen very strong electricity consumption growth during the past five years, contributing to around 6% of total demand gains. Demand in this sector in 2025 was estimated to be 2.2 times the value in 2020, mainly driven by a 900% higher New Energy Vehicles (NEV)[1] stock. New national policies incentivising switching from internal combustion engines (ICE) cars to EVs contributed to NEV sales growing by close to 30%, and surpassing 45% of total passenger vehicle sales in 2025. With China's NEV stock forecast to triple by 2030, we expect EV charging to contribute 10% to total demand growth over the forecast period, while further development in rail transport increases this share to over 13% in total for the transport sector.

Growth rates of sectoral electricity demand and GDP in China, 2000-2030



Notes: 3YMA = 3-year moving average. GDP growth is based on the IMF World Economic Outlook, October 2025.

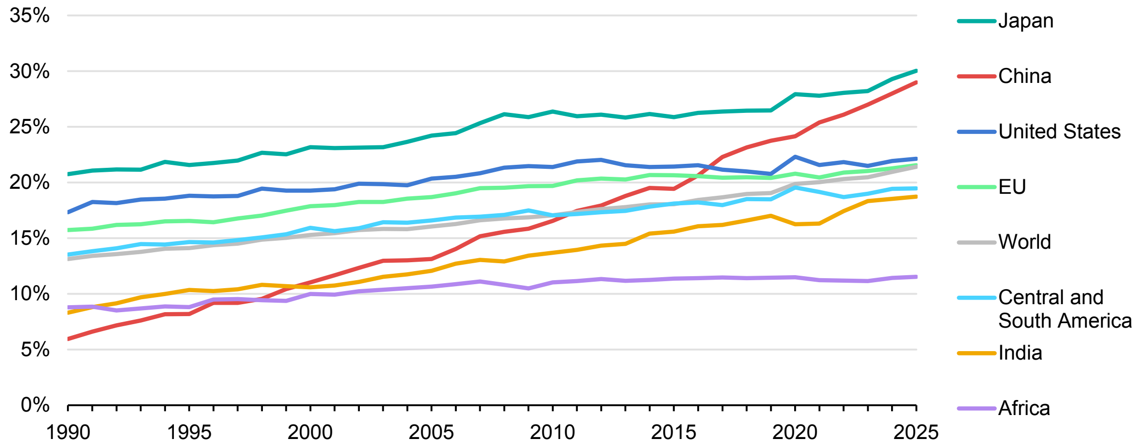
In terms of peak electricity load in China, structural growth in demand, expanding AC stock, and continued increases in cooling degree days in July and August led to nationwide load repeatedly hitting new record highs, reaching 1 508 GW on 17 July, up 3.9% from the 1 451 GW peak in 2024. Many Chinese provinces saw multiple record high peak loads last summer, leading to a peak of 442 GW in the East China Grid on 21 August 2025, up 5% y-o-y. A higher cooling load contributed to this peak, adding over 160 GW (37%). In Southern coastal urban areas, such as Shenzhen, AC load accounts for over 40% of the cities' grid peak load in summer. More generally, in the Guangdong province, which peaked at 164 GW in 2025 (up 4.4% y-o-y), load increases between 3 GW and 5 GW for every 1ºC rise in temperature above 35ºC.

The electrification of the Chinese economy, defined as the share of electricity in total final consumption, has outpaced that of any other major economy, particularly over the last 15 years. While electrification shares have stagnated just above 20%

[1] New Energy Vehicle is a term commonly used in China to describe all types of electric vehicles, including battery-powered, fully electric as well as plug-in hybrid vehicles.

in the United States, the European Union, Australia and New Zealand, and between 25% and 30% in Japan (the most electrified major economy globally), China's electrification has doubled since 2005, surpassing 27% in 2025.

Share of electricity in total final consumption in select countries and regions, 1990-2025

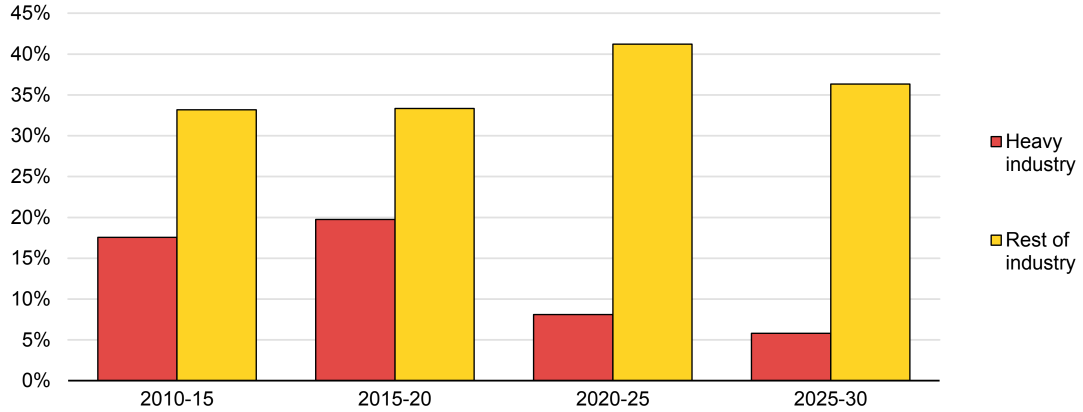


IEA. CC BY 4.0.

China's industrial demand growth is increasingly driven by electrified manufacturing outside heavy industry

Heavy industry, which covers iron and steel, non-metallic minerals and the chemicals and petrochemicals industries, has seen its contribution to total electricity demand growth decrease in recent years. While its share in demand growth was between 15-20% in the 2010s, this has fallen to well below 10% in the last five years, and is expected to decline further to around 6% over the forecast period, despite support measures and significant growth in the chemical and petrochemical subsector through 2030. Non-heavy industries have followed the opposite trend, reaching a more than 40% share of China's demand growth between 2020 and 2025, from 33% in 2010-2015. This growth has been driven by subsectors such as machinery, non-ferrous metals, transport equipment, textile and food industry. New energy products also had a very significant impact on this growth, as noted in our Electricity 2025 report.

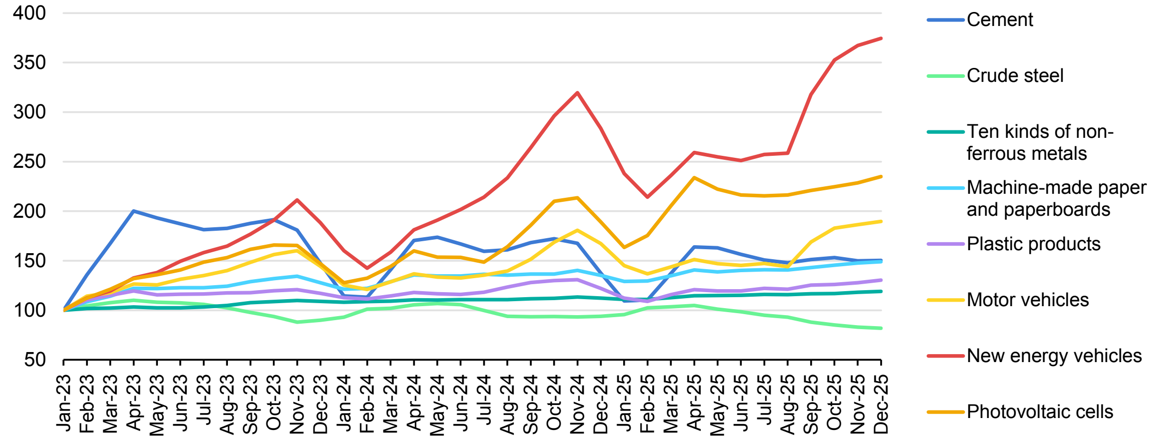
Contribution of heavy and non-heavy industries to electricity demand growth in China, 2010-2030



Note: Values correspond to the contribution to growth in annual electricity demand within each five-year period.

Part of the demand growth from industry in recent years has been driven by what China's authorities call internal involutionary competition, namely excessive, low-efficiency competition between firms that expand capacity and lower prices rather than by improving productivity and innovation. Involution competition is prominent across China's industrial sector, as illustrated by the producer price index for industrial products, which has recorded negative year-on-year growth since October 2022. The sales rate of industrial products has also trended lower in recent years, with the 2025 average at 96%, indicating that domestic and external demand combined have been insufficient to absorb industrial output. Oversupply and overcapacity particularly affect new industrial sectors such as EVs, batteries and PV manufacturing. In the case of PV modules, oversupply led to module inventories in China reaching an estimated 165 GW at the end of 2024, 15% higher than net capacity additions across advanced economies that year. To address the situation, China launched an anti-involution campaign in 2025, in which the key element is the guideline from the National Development and Reform Commission (NDRC) to build a national unified market, aiming at eventually resolving regional distortions by standardising and unifying economic, regulatory and technical rules.

Production indices of selected products in China, 2023-2025

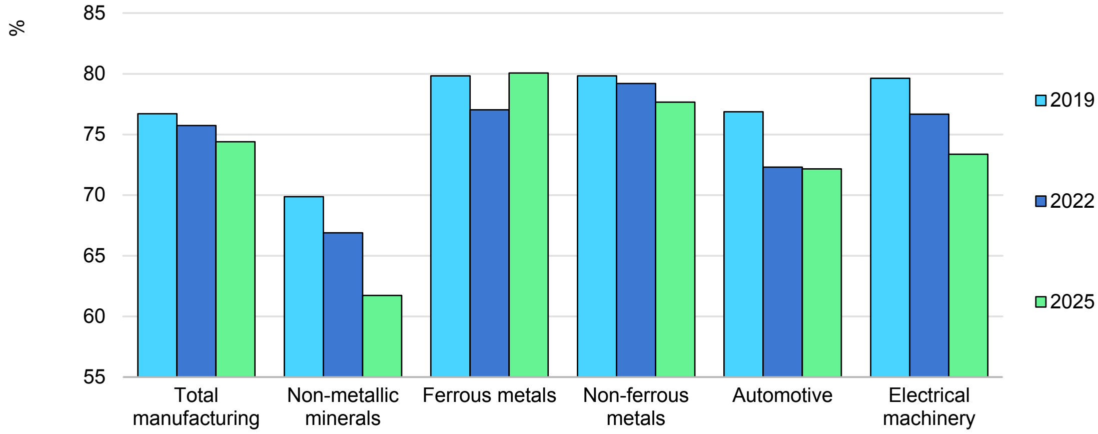


Note: Values for January and February have been estimated based on the 2-month aggregate provided by the National Bureau of Statistics of China.
Source: IEA analysis based on data from the National Bureau of Statistics of China (2025).

Even before the effect of these measures is observed, some industries related to new energy products (NEPs) started to self-regulate, often through agreements between the largest manufacturers to acquire and shut down capacity from smaller manufacturers. In the solar PV industry, top polysilicon producers were in talks in August 2025 to create a USD 7 billion fund to acquire and shut down one-third of the production capacity in the country. In December 2025, the China Photovoltaic Industry Association (CPIA) announced the launch of a platform for polysilicon consolidation aimed at addressing involution competition in the sector through government guidance, industry collaboration and market-based mergers and acquisitions. In addition, Chinese authorities announced plans to shut down any polysilicon producers which would not meet new energy consumption thresholds within one year. Polysilicon production in China declined in 2025, compared to the previous year, for the first time since 2013, while wafer production also saw its first year-on-year contraction since 2009.

Despite corrections in the short term, we expect demand from China's non-heavy industries to grow by close to 1 000 TWh over the five-year 2026-2030 period, even if growth rates are expected to remain slightly lower than what was observed in 2023 and 2024.

Industrial capacity utilisation rates by selected subsector, China, Q1-Q3, 2019-2025



Source: IEA analysis based on data from the National Bureau of Statistics of China (2025).

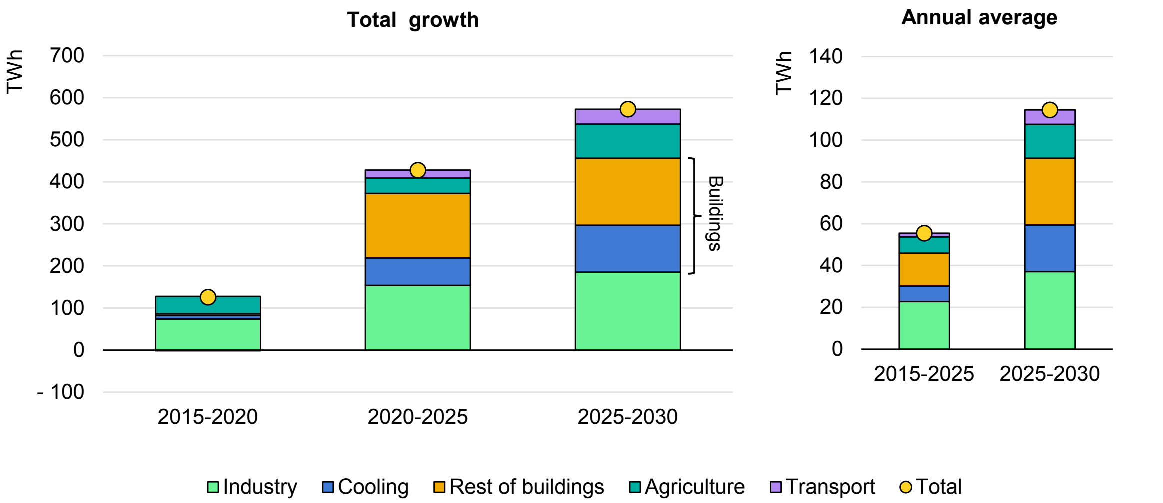
Peak load and demand rise across India, driven by cooling, industry and agriculture

After four years of growth rates above 6%, India's demand grew by a modest 1.4% in 2025. Despite strong fundamentals supporting increased demand of 5.8% in the first four months of the year, the early arrival of monsoon in May brought milder temperatures and increased precipitation, leading to lower use of AC and agricultural pumping. Cooling degree days were more than 7% lower in 2025 than in 2024, with a particularly sharp decrease in June (-12%), when hot weather has driven, on average, 15% of monthly demand nationwide in recent years.

In the five-year period between 2021 and 2025, net electricity demand in India grew by close to 430 TWh. Space cooling contributed 15% to total demand growth, and to around one-third of the gains in the buildings sector. This sector, which includes households and services, has driven half of the total growth in India over the past five years. Industry accounted for 36% of total growth, while agriculture and transport provided the rest.

Over the forecast period, we expect demand in India to grow at an average 6.4% per year through 2030, in line with IMF's GDP forecasts. India is expected to add over 570 TWh to its annual consumption in the next five years. The industrial sector is expected to contribute to a third of this growth, while the share of households and services will decrease slightly compared to the past five years. The growing stock and usage of AC units in 2026-2030 results in cooling to account for over 20% of total demand growth in our forecast. Electrification and development of India's agriculture and transport infrastructure lead to these two sectors jointly driving around one-fifth of total demand growth to 2030.

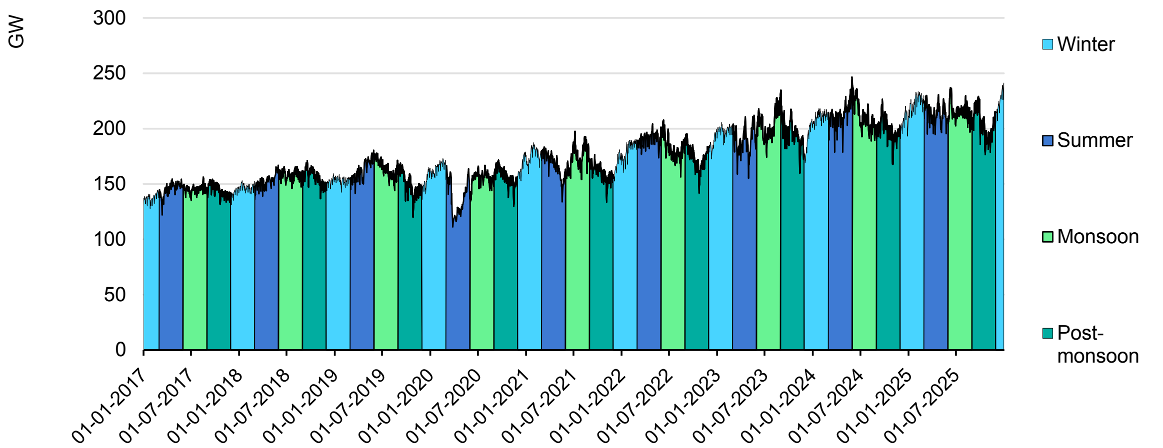
Electricity demand growth by sector and end use in India, 2015-2030



Distinct factors shape growing peak load in India's five regional grids

Electricity demand across India has shown significant seasonal variations over the past decade, with a cumulative increase in peak loads of 54%, from 162 GW in 2017 to 250 GW in 2024. In recent years, the national peak load consistently hit its highest levels during the summer months amidst long heatwaves, reflecting increased cooling demand and high pre-monsoon agricultural electricity use.

Evolution of nationwide daily peak load in India by season, 2017-2025



Sources: IEA analysis based on data from IEA Real-Time Electricity Tracker (2025), Merit India (2025).

The interplay between regional loads determines the profile of India's electricity demand and offers opportunities for interregional trade given diverse seasonality. The country's national power grid is divided into five regional grids: Northern Region (NR), Western Region (WR), Southern Region (SR), Eastern Region (ER) and Northeastern Region (NER). These grids, which were initially isolated, reached full interconnection at a national level in 2013. The current inter-regional capacity of the grid is above 120 GW, while both inter-state and intra-state transmission capacity is growing steadily under India's Green Energy Corridor schemes. These grid expansions are essential to integrate India's target of 500 GW of non-fossil installed capacity by 2030, up from 267 GW in December 2025, but also to meet the energy and peak load requirements of each region and state.

Subnational electricity grids in India and main indicators, 2025

Grid	Most populated states	Electricity supplied annually (share)	Record-high met peak load (date)	Nature of demand
Northern Region (NR)	Uttar Pradesh, Rajasthan, Punjab	475 TWh (29%)	90.8 GW (June 2025)	Agriculture, residential, services
Western Region (WR)	Maharashtra, Madhya Pradesh, Gujarat	517 TWh (32%)	80.5 GW (February 2025)	Heavy industry, services, residential
Southern Region (SR)	Tamil Nadu, Karnataka, Andhra Pradesh	419 TWh (26%)	69.9 GW (March 2025)	Services, industry, residential, agriculture
Eastern Region (ER)	Bihar, West Bengal, Odisha	191 TWh (12%)	33.5 GW (July 2025)	Industry, residential, agriculture
Northeastern Region (NER)	Assam, Tripura, Meghalaya	20 TWh (1%)	4.1 GW (July 2025)	Residential, agriculture

Note: Electricity supplied data covers financial year 2023/24.
Source: IEA analysis based on data from Central Electricity Authority (2025).

In the Northern Region, peak load trends closely follow the national pattern, with the highest demands recorded during the summer months, typically in May or June. This is largely due to the extreme temperatures experienced in this region, leading to increased use of air conditioning. Close to 30% of the annual national demand comes from this region, which also sees substantial demand during the post-monsoon period, driven by the agricultural sector's irrigation needs. Conversely, winter months from December to March see a significant dip in demand, despite stronger heating requirements and other industrial and commercial activities.

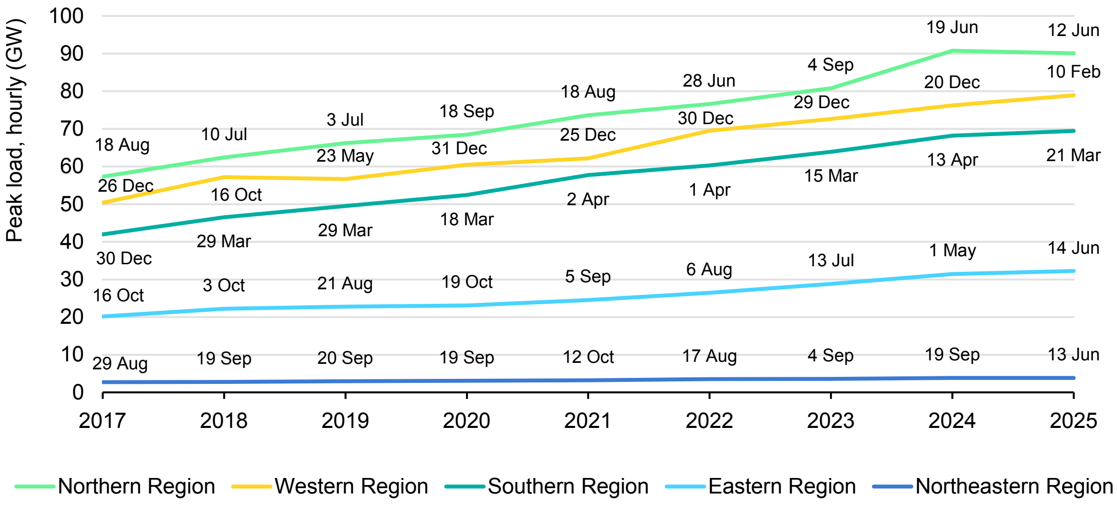
The Western Region, while experiencing high summer peak loads, benefits from a more diversified industrial base, including energy-intensive and heavy industries, which can distribute electricity demand more evenly across the year. Historically, peaks have typically occurred during Q4 or Q1 as businesses increase production and operations as they approach the end of the financial year.

The Southern Region also shows a pronounced peak in electricity demand during the early summer months, which result from the combination of hot, humid weather boosting cooling demand and continued industrial activity. In addition, the SR's peak loads are notably high during the monsoon season from mid-June to September. The SR's demand is more evenly distributed across seasons compared to other regions, although the winter period still records the lowest peak loads.

The Eastern Region, with lower overall peak loads, has a balanced mix of residential, agricultural, and industrial electricity use. The lowest subnational peak loads in Northeastern Region reflect its smaller population and lower industrial activity, with minor seasonal peaks driven largely by residential heating and cooling needs.

Relative growth in subnational yearly peak loads has remained roughly similar across regions between 2017 and 2025, with values growing by 57% in the NR and WR, 65% in the SR, 60% in the ER, 43% in the NER.

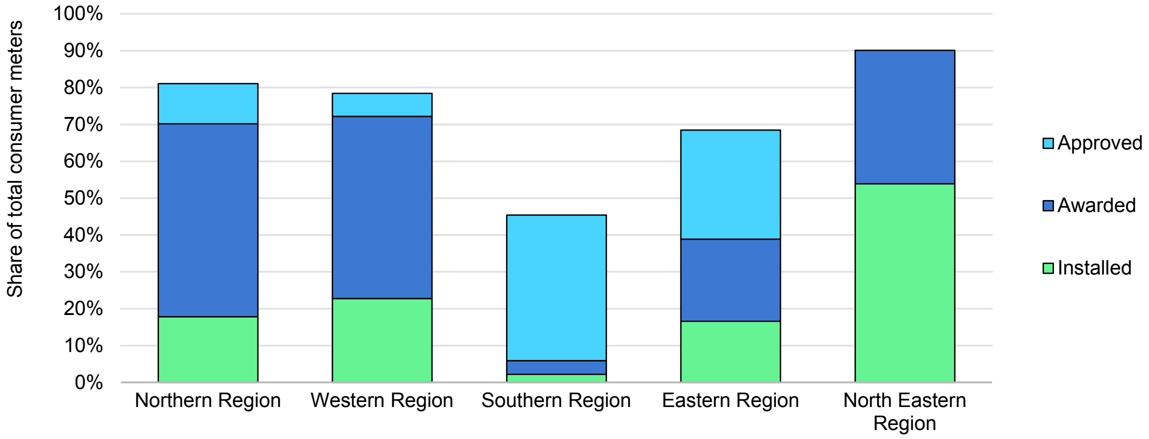
Annual peak load, hourly, by India's subnational grids, H1 2017-2025



Note: 2025 data include values for the January-June period.
Source: IEA analysis based on data from NITI Aayog (2025), Grid-India (2025).

Policies such as PM-KUSUM for the agricultural sector, and the generalisation of Time of Day (ToD) tariffs, have contributed to shifting part of the evening load growth to daytime, leading to an increased concentration of demand during hours in which solar PV output is at its highest. Nationwide deadlines for ToD tariff implementation were defined in the Electricity (Rights of Consumers) Amendment Rules, 2023, stating that this type of tariff should be made available for industrial and commercial consumers from April 2024, and for other consumers except agricultural from April 2025. However, in practice, only consumers with smart meters have access to these tariffs, and the deployment of smart meters has been uneven across India, with more than 29% of approved meters installed in the WR versus less than 5% in the SR. Overall, 22% of approved smart meters have been installed in India as of December 2025. Further progress in these projects will unlock more demand flexibility from peak evening hours to solar hours.

Consumer smart meter deployment progress by India's subnational grids, December 2025



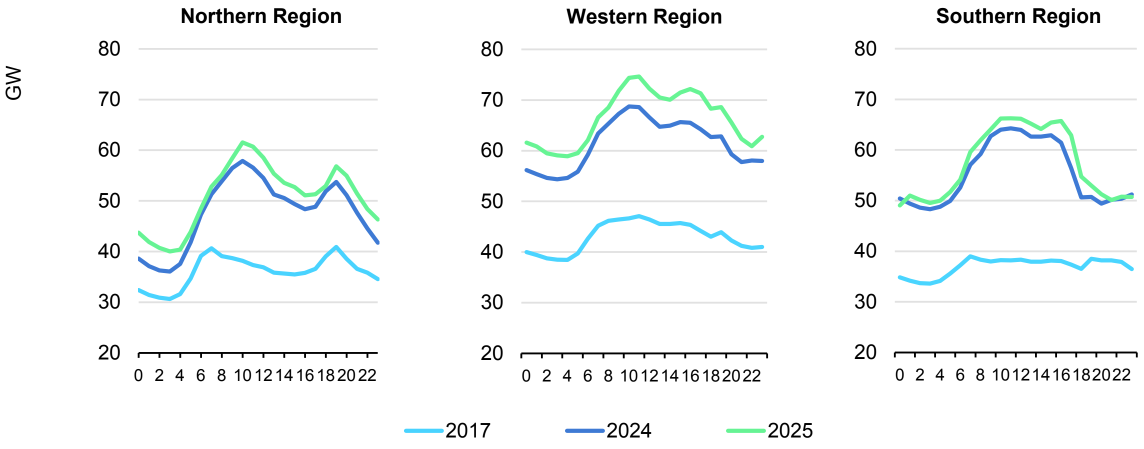
IEA. CC BY 4.0.

Notes: Data covers all consumer categories billed by DISCOMs, and all IS-16444 standard certified Smart Meter deployment schemes/projects. 'Approved' covers projects formally authorised. 'Awarded' covers contracts or tenders granted. 'Installed' covers systems physically deployed. Consumer meters include the following sectors: residential, commercial, public services, and agriculture.
Source: IEA analysis based on data from India, Ministry of Power (2025), NITI Aayog (2025).

The early monsoon season moderated nationwide peak load in 2025

Data from February-March 2025 show that increased development of industrial and commercial activities, together with higher agricultural and residential use, significantly drove daily load upwards structurally in all regions compared to 2024. In addition to 6.6% GDP growth in 2025, industrial production rose by 3.5%, while sales of appliances continue to grow over 10% annually, and data centre demand expanded by close to 50%. This is particularly visible in the WR, where industrial states like Maharashtra, also home to more than half of India's operating data centre capacity, outpaced national economic growth. In this grid region, more than 6 GW were added to the February-March average load at 11 am (+9%).

Average February-March daily load curve by selected Indian subnational grids, 2017-2025

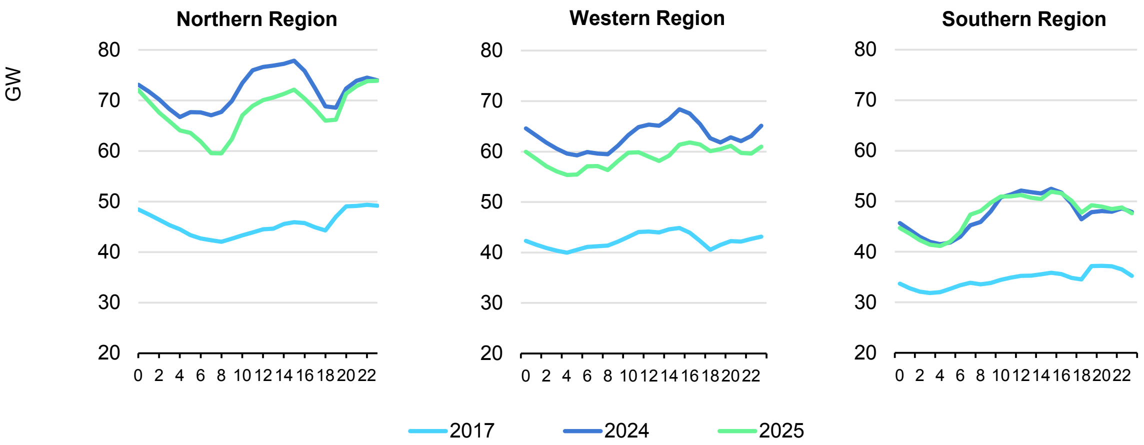


Source: IEA analysis based on data from NITI Aayog (2025), Grid-India (2025).

After a particularly hot summer with heatwaves covering the country as early as April, India witnessed the arrival of an abundant monsoon around 9 days earlier than the 10-year average in May 2025. Torrential rains led to significant damage and a decrease in temperatures compared to 2024, limiting nationwide peak load to 241 GW on 9 June, fully met by growing installed capacity.

Data from May-June shows that the load increase observed in the first quarter of 2025 compared to a year earlier faded away as a result of lower temperatures and increased precipitation, leading to a decrease in the use of ACs and irrigation pumps. Average demand was weaker in all regions, with the most significant drop seen in the WR, where average load was 7 GW lower than in 2024 at 3 pm (-10%).

Average May-June daily load curve by selected Indian subnational grids, 2017-2025



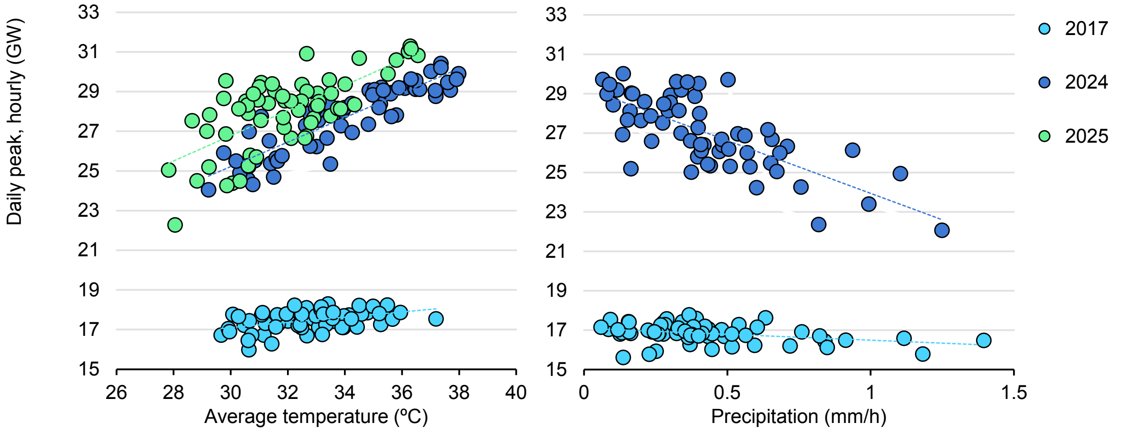
Source: IEA analysis based on data from NITI Aayog (2025), Grid-India (2025).

The impact of weather in moderating the 2025 nationwide peak demand becomes visible when comparing daily peak load with average temperature and rainfall values for India's most populated state, Uttar Pradesh (NR). Growing AC stock and electric irrigation pumps are major drivers of demand and peak load growth, particularly in the NR.

Between May-June 2024 and the same period in 2025, an increase of close to 2 GW is observed in daily peak load trendlines. Considering Uttar Pradesh's peak load in 2024 was 30.6 GW, the value for 2025 could have surpassed 32.5 GW if summer temperatures in this state had reached the same levels as the previous year. However, given lower overall temperatures, the maximum load for 2025 remained below 31.5 GW. Since 2017, additional peak load associated with a 1°C increase in average temperature has risen fivefold, indicating a sharp increase in AC penetration in the state.

In the agricultural sector, accounting for 16% of total demand in Uttar Pradesh, irrigation pumps are increasingly electrified and connected to feeders with distributed solar PV resources. Given that various programmes have encouraged their use during daytime hours, part of the typical evening load has switched to the afternoon, increasingly contributing to the daily peaks in summer and the monsoon season. The use of irrigation pumps decreases when monsoon rainfall levels are high, resulting in a reduction of close to 5.5 GW in the state's daily peak per 1 mm/h (24 mm/day) of precipitation, compared to an impact of less than 1 GW in 2017.

Daily peak load, hourly, versus average temperature (May-June) and versus precipitation (July-August) in Uttar Pradesh, NR, 2017-2025

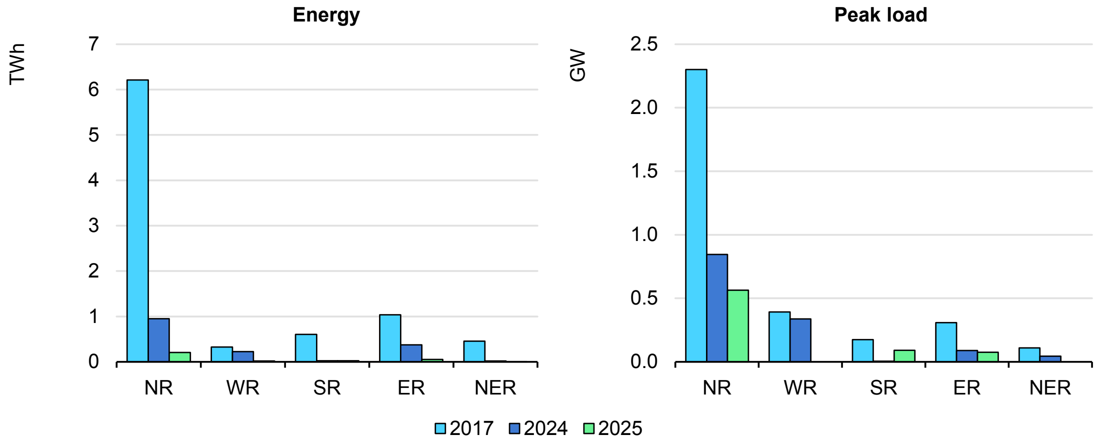


Notes: Data for July-August 2025 were not available at the time of publication.
Sources: IEA analysis based on data from NITI Aayog (2025), Grid-India (2025), IEA Weather for Energy tracker (2025).

Regional grids secure adequacy as peak load becomes more pronounced

Resource adequacy plans led by the Central Electricity Authority (CEA) found that a majority of states will likely have significant shortages by 2034 even if all planned capacity is commissioned on time, thus requiring further annual capacity contracts by source, mainly coal-fired, variable renewable energy (VRE) and storage capacity. The plans state that unserved energy could surpass 38 TWh (14.9%) in Uttar Pradesh (NR) in 2030, 20 TWh (10.1%) in Tamil Nadu (SR), 11 TWh (11%) in West Bengal (ER) or 7 TWh (30%) in Assam (NER) the same year. Meanwhile, adequacy forecasts are more manageable in Maharashtra (WR), where values of unserved energy could remain just above 3 TWh (1.6%) in 2030. This is despite the declining rates of yearly unserved energy and unmet peak load in recent years in all regions. Between 2017 and 2025, values for the former have dropped by more than 7 TWh, or 97%, nationwide, while unmet peak load decreased by 78% over the same period.

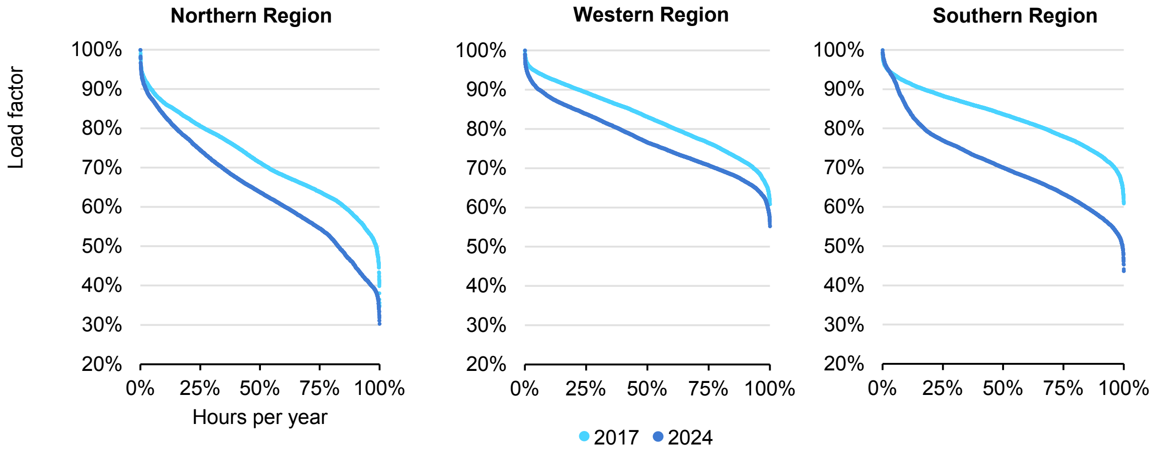
Energy not supplied (left), and unmet yearly peak demand (right), by India's subnational grids, 2017-2025



Note: NR = Northern Region, WR = Western Region, SR = Southern Region, ER = Eastern Region, NER = Northeastern Region.
Source: IEA analysis based on data from Central Electricity Authority (2025).

With regional and national peak loads rising faster than average demand, generation asset planning across India has expanded focus from energy requirements to meeting peak load. Load factors, defined here as hourly demand expressed as a share of yearly peak demand, are an important indicator to understand the relative magnitude of demand peaks. Load duration curves, which show the distribution of load factors across the year, have become steeper in recent years, indicating an increasing concentration of high load levels in a limited number of hours per year. This is particularly the case in the SR, where load levels at or above 80% of peak demand are currently observed in only 17% of yearly hours, compared to two-thirds of yearly hours in 2017. Load factors above 80% are attained in 15% and 38% of the yearly hours in the NR and WR respectively. Among other factors, the decrease in energy not supplied and unmet yearly peak demand shown above contributes to this trend, as outages at peak hours tend to flatten load duration curves.

Load duration curves by selected Indian subnational grids, 2017-2024



Source: IEA analysis based on data from NITI Aayog (2025), Grid-India (2025).

Overall, India has made remarkable progress in narrowing supply-demand imbalances in recent years, with unmet peak load and unserved energy values declining steadily between 2017 and 2025. Despite the positive results in 2025, continued structural growth in both annual demand and peak load, driven by economic activity and cooling needs, will continue to put attention on adequacy, particularly in the Northern Region. Expanded generation capacity across thermal, renewable and nuclear sources, improved coal fleet availability, strengthened inter-state interconnections, demand response and batteries are essential tools for addressing these challenges.

Supply

Renewables and nuclear keep growing and setting records

Global electricity generation will reach multiple new milestones in our 2026-2030 forecast period. This is particularly the case for low-emissions generation sources – renewables and nuclear – which will continue expanding and setting new records. Renewable energy is now outpacing coal, with nuclear generation simultaneously reaching historic highs. Constrained by growth in low-emissions sources, coal-fired generation globally is forecast to record slight declines, where demand growth through 2030 will be met by renewables, natural gas and nuclear. While trends for individual fuels vary by region, a common theme is the strong expansion of solar PV in many power systems. This chapter provides an overview of global supply developments in 2025 and a summary of our forecasts through 2030 for the major economies. A detailed coverage of other individual regions and countries can be found in the Regional Focus section of the report.

Share of renewables and nuclear in global electricity generation reaches 50% by 2030

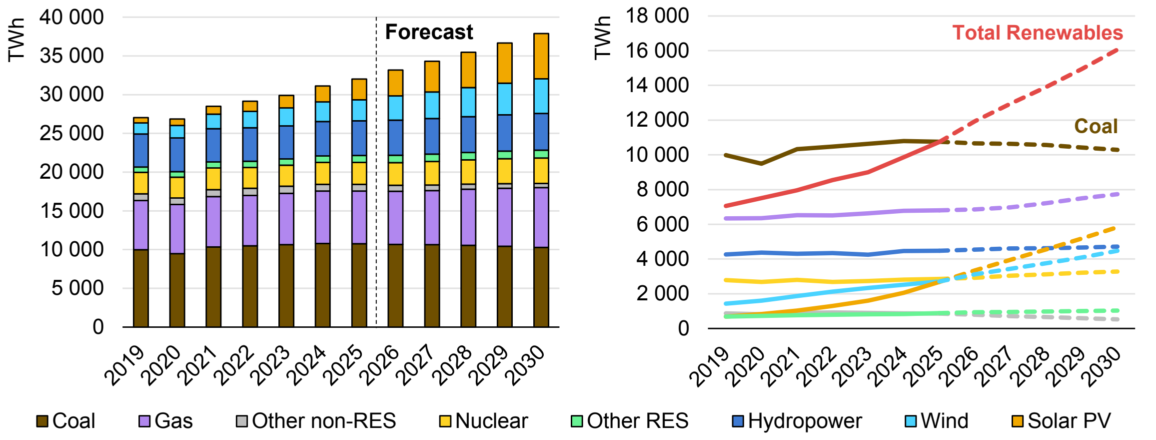
Global renewable generation is overtaking coal-fired output, consistent with the IEA's previous forecast. Renewable generation virtually reached the levels of coal-fired output in 2025 based on the latest available data, even though declines in hydropower in Europe and Eurasia and lower-than-normal wind speeds, particularly in Europe, slowed the pace of growth. Renewables share surpassed the one-third threshold in 2025, up from only 23% a decade ago.

Renewable electricity generation is expected to rise each year by roughly 1 050 TWh. Of this, more than 600 TWh on average is set to come from solar PV alone annually to 2030, thanks to rapid uptake in many regions of the world amid strong cost declines. In 2025, growth in global electricity generation from solar PV saw the largest year-on-year increase, at 620 TWh, compared to 450 TWh in 2024. Solar PV generation is expected to overtake wind and nuclear by 2026 and hydropower by 2029.

Low-emissions energy sources – renewables, led by solar, and nuclear – will see their share in global electricity generation rise to 50% through 2030, up from 42% in 2025. Strong growth in renewables and a steady rise in both nuclear and gas output in many regions will displace global coal-fired generation in our forecast.

Coal use in the power sector is expected to shift to a declining trajectory, with its share of the electricity mix falling to 27% by 2030, from 34% in 2025.

Global electricity generation by source, 2019-2030



Notes: RES = renewable energy sources. ‘Other non-RES’ includes oil, waste and other non-renewable sources. ‘Other RES’ includes geothermal, bioenergy, concentrated solar power (CSP), and ocean energy. Data for 2026-2030 are forecast values.

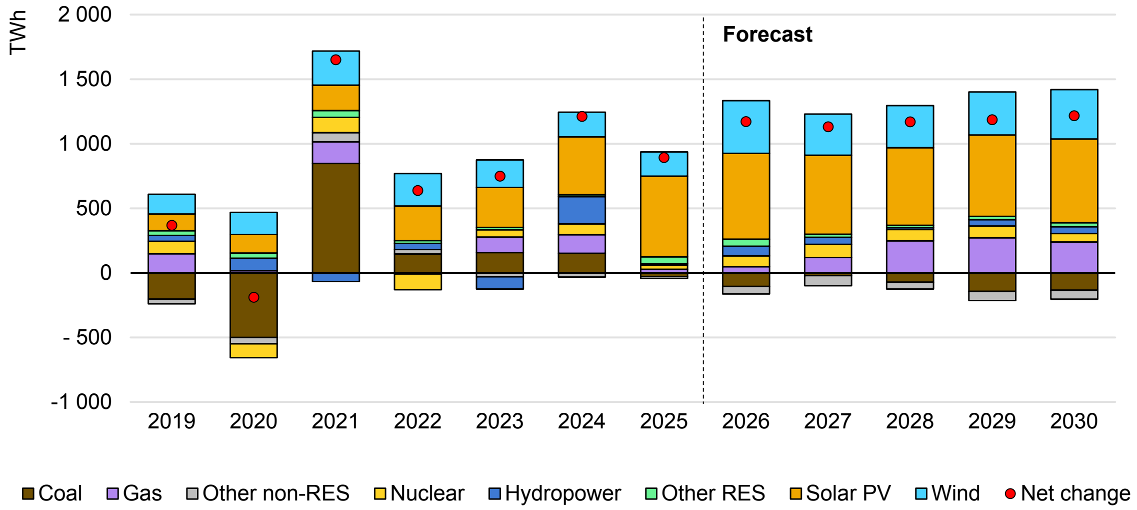
Growth in renewables, natural gas and nuclear set to meet additional demand

Low-emissions sources maintained strong growth momentum in 2025, with renewables rising by 9%. This was slightly lower than the 9.6% increase in 2024, as weather conditions dampened growth in wind and hydropower generation. Nonetheless, 2025 growth was still well above the 6.4% average observed over the past decade. Coal-fired generation remained relatively flat in 2025, following a 1.4% increase in 2024. Declines in China and India were offset by gains in the United States, Eurasia and other Asian markets. Natural gas-fired output grew by around 0.5% y-o-y, a moderation from the 2.2% in 2024, amid gas-to-coal switching in various regions due to higher gas-prices compared to 2024. Nuclear generation was up 1.2% y-o-y, supported by restarts in Japan, higher output in France, and newly commissioned reactors in China and other countries. By contrast, oil-fired generation declined by around 2%, largely due to oil-to-gas switching in the Middle East.

In the 2026-2030 forecast, coal-fired output contracts by 0.9% on average annually. Despite the declining trend, coal will remain the largest single source of electricity through 2030. The plateauing trend of coal-fired generation in China, where more than half of world’s coal-fired output takes place, is a major catalyst in this trend. By contrast, global gas-fired output is set to grow at an accelerated rate of 2.6% in 2026-2030. This is supported by strong growth in gas-fired generation in the United States amid robust electricity demand and in the Middle East with rapidly expanding oil-to-gas switching, especially in Saudi Arabia.

Renewables are forecast to maintain robust growth out to 2030, at an average 8.4%. The share of variable renewable energy (VRE) is set to sharply increase over the forecast, with solar PV and wind combined rising from 17% of total generation in 2025 to 27% by 2030. Solar PV sees the strongest growth among all generation sources, adding on average more than 600 TWh annually, and almost doubling its share to 15%, up from around 8% in 2025. Wind generation is forecast to grow at an average annual rate of around 10%.

Year-on-year global change in electricity generation by source, 2019-2030



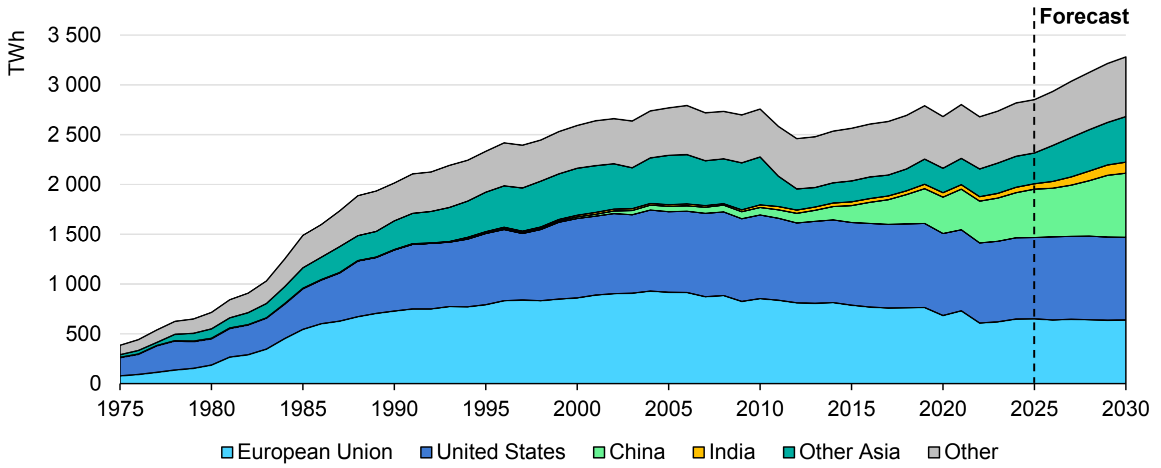
Notes: RES = renewable energy sources. ‘Other non-RES’ includes oil, waste and other non-renewable sources. ‘Other RES’ includes geothermal, bioenergy, concentrated solar power (CSP), and ocean energy. Data for 2026-2030 are forecast values.

Nuclear generation is set to increase by an average of 2.8% over our forecast period, more than double the 1.3% growth rate in 2021-2025. The gains are led by new reactors being commissioned in China, India, Korea and other countries, restarts in Japan, and robust output in France from the planned advancement of the maintenance works. Nuclear electricity output is expected to remain relatively stable in both the United States and the European Union over the forecast period, while it increases strongly in China, where almost 30 GW of new nuclear capacity is expected to come online over the five-year 2026-2030 outlook.

Nuclear generation in China is expected to increase by nearly 6% per year on average through 2030, while output in the United States and the European Union remains broadly stable. Consequently, China’s share of global nuclear generation is projected to rise from 17% in 2025 to 20% in 2030, whereas the United States’ share declines from 29% to 25% and the European Union’s share falls from 23% to 20%. Despite these falling shares, increasing nuclear generation is a major focus in the United States, with new small modular reactor (SMRs) capacity slated to come online just outside our 2026-2030 forecast period. There is also strong interest in many countries of the European Union, with policies in place for lifetime extensions and expansion of nuclear capacities.

Globally, SMRs are receiving particularly high levels of attention, both from the public sector and also from private industry, such as from large technology companies, as the modular designs and smaller scale of SMRs make them more attractive for financing and deployment by the private sector. Nevertheless, as highlighted in the IEA’s report The Path to a New Era for Nuclear Energy, the success of the technology depends on a combination of government commitment and supportive policies, timely regulatory design reviews, continued innovation from technology developers, and financing from both public and private sectors.

Global nuclear generation by countries and regions, 1975-2030



Note: Data for 2026-2030 are forecast values.

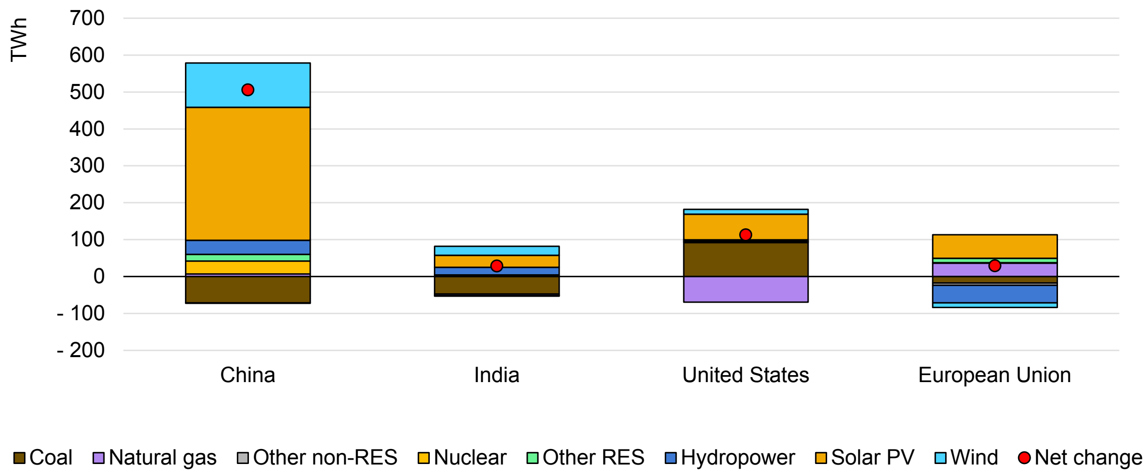
Uncharacteristic trends in coal-fired generation observed during 2025

Fossil-fired generation trends varied in 2025 across major economies, showing some uncharacteristic developments. In contrast to the overall trends observed in recent years, coal-fired generation declined year-on-year in India and China, whereas it increased in the United States, and declined less than expected in the European Union. 2025 also marked the first time in five decades that coal-fired generation declined simultaneously both in India and China.

In India, coal-fired output declined as rapid renewable expansion outpaced slower electricity demand growth. A strong early monsoon curbed consumption, while renewable generation saw its largest-ever annual increase, displacing coal. By contrast, coal-fired generation in the United States rose, as higher natural gas prices compared with the previous year, strong electricity demand growth and a slowdown in coal plant retirements due to federal policy support led to higher coal use in the power sector. In the European Union, despite record-breaking solar PV generation, declines in wind and hydropower resulted in higher year-on-year gas-fired generation and stronger-than-expected coal-fired output. In China, strong growth in renewables and nuclear − combined with slower demand growth than in 2024 − led to a decline in coal-fired generation.

We expect the structural trend in China observed in 2025 to continue through 2030, with coal-fired output edging down as renewables and nuclear keep expanding. Over our forecast period, both the European Union and the United States are expected to see declines in coal-fired generation. By contrast, India's recent decline is expected to be temporary, with coal-fired output projected to resume rising over the forecast period.

Year-on-year change in electricity generation by source in selected regions, 2025



Notes: RES = renewable energy sources. 'Other non-RES' includes oil, waste and other non-renewable sources. 'Other RES' includes geothermal, bioenergy, concentrated solar power (CSP), and ocean energy.

In **China**, solar PV generation increased by more than 40% y-o-y in 2025 and wind by around 12%. The annual VRE share in overall electricity generation reached 22%, up from 18% in 2024. Hydropower generation posted growth of 2.8%, while nuclear output rose by 7.7%, supported by new capacity additions. Gas-fired generation, which only accounts for around 3% of the electricity generation mix, is estimated to have increased by around 2%, compared to 7% in 2024. Coal-fired generation declined by around 1%, due to weaker demand and growth in low-emissions sources, versus a rise of 1.3% in 2024.

Renewable electricity generation grew in **India** by 20% in 2025, posting their absolute strongest annual increase (+82 TWh) on record. Growth was led by solar PV generation (+24% y-o-y), with 33 TWh of additional generation. This is a notable rise from the already strong 15% growth seen in 2024. Wind power generation was up 28%, while hydropower rose by 14% amid improved hydrological conditions. By contrast, nuclear generation decreased by 1.6%. Given strong increases in low-emissions sources in a year when the country's overall electricity demand growth rate remained relatively muted at 1.4%, coal-fired generation fell by 3.2%, after a 5% rise in 2024. Gas-fired generation similarly is estimated to have declined by 9%, after rising by 6% in 2024.

In the **United States**, electricity demand remained strong, rising by 2.1%. Electricity generation from solar PV rose by 70 TWh (+26%) in 2025. Total renewable output increased by more than 8%, with higher solar PV generation alone accounting for about 80% of the gains. By contrast, wind generation growth slowed to 2.9%, compared to 7.6% in 2024. Coal-fired electricity was up by a sharp 13% y-o-y in 2025, rebounding strongly following a contraction of almost 3% in 2024, while gas-fired generation declined by 3.6%.

In the **European Union**, solar PV and wind generation combined surpassed fossil-fired generation in 2025, marking a milestone. Renewables share in total electricity generation approached 48%. Solar PV generation rose by a substantial 22%, overtaking hydropower to become the second-largest source of renewable electricity, behind only wind energy. At the same time, amid reduced wind speeds, wind generation was down 2.6% y-o-y and hydropower fell by around 13% due to reduced rainfall. Nuclear generation remained stable in 2025 amid robust output in France and a number of other countries. Even though EU electricity demand growth was less than 1%, lower wind and hydropower generation contributed to higher gas burn in the power sector, which increased by around 8%. Equally, weather effects led to a more moderate 6% decline in coal-fired generation, compared with an average annual decline of more than 20% in 2023 and 2024.

Strong solar PV growth through 2030 remains a common trend across the regions

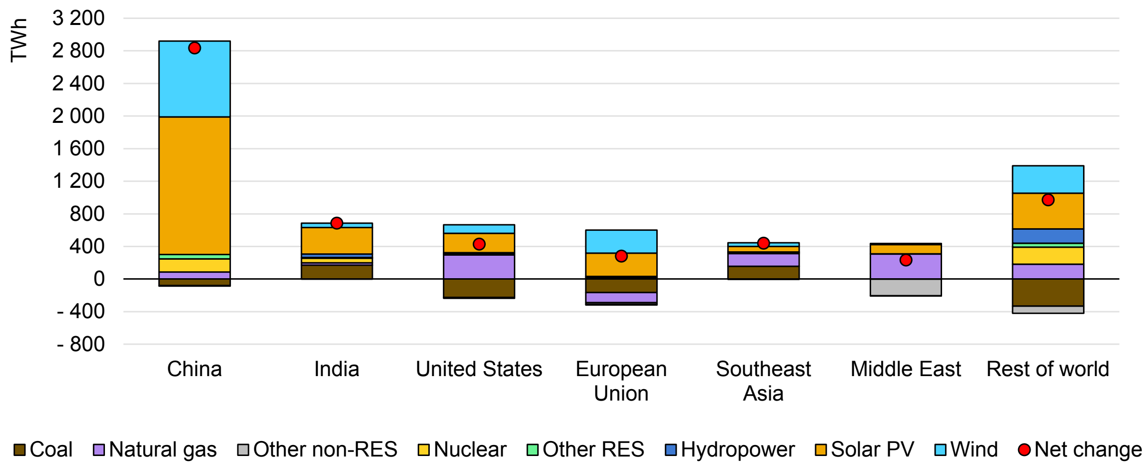
In many parts of the world, electricity generation from ever-cheaper solar PV is showing the largest growth among supply sources. Over our forecast period, the share of solar PV in the total electricity generation mix will surpass 10% in many major economies, and even reach 20% in some of these countries. In terms of absolute and relative growth in solar PV, **China** leads the way among major economies. The solar PV share surpassed the 10% threshold in China in 2025 and is set to exceed the 20% mark in 2030. After a year-on-year increase of

360 TWh in 2025, solar PV generation is forecast to rise by 320-360 TWh every year out to 2030, meeting around 60% of the average annual demand growth.

We expect all of China's additional electricity demand in 2026-2030 to be met by low-emissions sources, renewables and nuclear energy. The total increase in solar PV generation in China over the next five years will be larger than the combined increase in solar PV generation in the rest of the world. Similarly, with an annual average growth rate of 13%, the increase in wind generation in the same period is forecast to be higher than all the growth in wind generation globally. The VRE share in electricity generation is expected to reach 37% by 2030, up from 22% in 2025 and the share of total renewables is forecast to approach the 50% mark, rising from 37%.

In addition to renewables, nuclear generation is also set to expand strongly, at an annual average rate of 5.9%. As a result, despite forecast 4.9% growth for electricity demand, coal-fired generation in China is expected to stay at a plateau as low-emissions sources constrain coal-fired generation. By contrast, gas-fired generation is set to rise on average by around 5% annually through 2030, supported by expectations of lower LNG prices due to expanding global supply.

Change in electricity generation by source in selected regions, 2025-2030



Notes: RES = renewable energy sources. 'Other non-RES' includes oil, waste and other non-renewable sources. 'Other RES' includes geothermal, bioenergy, concentrated solar power (CSP), and ocean energy.

In **India**, around 50% of the additional demand growth through 2030 is forecast to be met by solar PV and 25% by coal, with the remainder supplied by wind, nuclear, hydropower and gas. Solar PV generation is expected to rise by an average annual 24%, with its share in total generation set to reach the 10% mark in 2026 and approach 18% in 2030. Wind generation is also forecast to increase at a strong pace, growing by 8.2% on average annually. As a result, the VRE share in total electricity generation is expected to reach 24% in 2030, rising from 14% in

2025. The total renewables share is set to surpass the one-third mark in 2030, up from 24%. At the same time, nuclear generation is forecast to post strong gains, rising by an average rate of 15% over the forecast period, as new reactors become operational.

Despite a slowdown in growth in 2025 amid weather impacts, electricity demand in India is expected to increase at a strong annual average 6.4% through 2030. As a result, higher coal burn in the power sector is set to continue, rising on average by around 2.5% over the next five years. Coal will maintain its role as the main source of electricity supply, though its share in generation is expected to fall from around 70% in 2025 to 60% by 2030. Gas-fired generation is forecast to rise annually by 9.7% on average, supported by a more favourable LNG price environment.

In the **United States**, we expect substantial growth in gas-fired output, followed by solar PV expansion and slight increases in wind generation, to meet rising demand over the 2026-2030 period, while coal-fired generation decreases. The United States is the only major economy where despite substantial growth in solar PV, its share in total generation rises at a more modest pace, as other sources such as natural gas are expected to increase at significant rates. Having exceeded 7% in 2025, solar PV’s share in US electricity generation is expected to reach 10% in 2028, increasing to 11% in 2030. By contrast, the share of wind is expected to stay at around 10% in 2030, similar to its share in 2025. The VRE share in the electricity generation mix is forecast to rise from 18% in 2025 to 23% in 2030, with the total renewables share increasing to 29%. During the same period, nuclear generation is expected to remain stable, at slightly higher levels than in 2025.

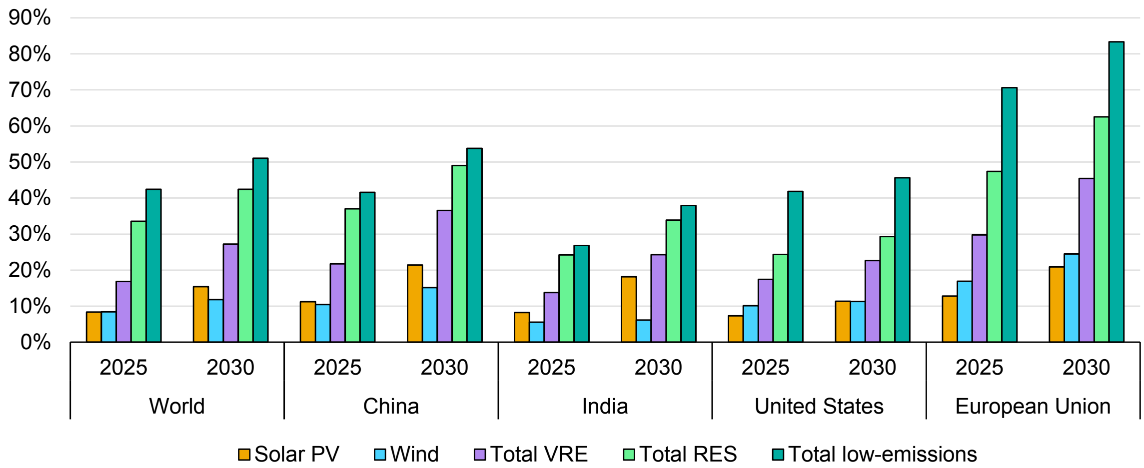
Strong growth in electricity demand through 2030 contributes to sustained growth in natural-gas fired generation, which is forecast to rise at an annual average rate of 3%. Coal-fired generation looks set to decline by an average 6.3% per year. Nevertheless, the decline rate is highly dependent on the progression of coal power plant retirements. The government has demonstrated a willingness to delay the retirement of coal-fired power plants, and has taken steps to do so, in response to strong growth in electricity consumption, including demand from data centres.

In the **European Union**, we expect renewables to meet all the demand growth over our forecast period, displacing fossil-fired generation. Solar PV generation already eclipsed the 10% mark in 2024 and will reach 20% by 2030. In 2026-2030, more than 400 GW of net renewable energy capacity is projected to be added, with 70% coming from solar PV alone. Wind power generation is also forecast to post strong gains, up by 10% on average annually. Wind is set to be the largest source of electricity generation in the European Union over the forecast horizon, overtaking nuclear energy, and its share will rise from 17% to 25% by 2030. Similarly, the share of VRE is expected to reach 46% in 2030, up from 30% in

2025. By 2026, EU renewable generation will be higher than the combined non-renewable generation. Correspondingly, the share of renewables in total electricity generation is set to reach 63% in 2030, up from 48% in 2025. Combined with nuclear energy, the share of low-emissions sources is forecast to reach 84% by 2030.

As renewables continue their strong growth and nuclear power generation remains stable, fossil-fired generation will continue to be displaced. Coal-fired generation will decline through 2030, falling on average by 16% annually, while at the same time coal phase out plans in various EU countries continue to take place through 2030. Natural gas-fired supply is also forecast to post declines, at an average rate of close to 6%. Nevertheless, gas-fired generation will continue to play an important role in providing seasonal flexibility as well as ancillary services for system stability.

Shares of energy sources in total electricity generation in select regions, 2025-2030



Notes: Total VRE = variable renewable energy (solar PV + wind); Total RES = renewable energy sources (VRE + other renewables); Total low-emissions = Total RES + nuclear energy. Data for 2030 are forecast values.

The common trend of strong solar PV growth is also seen in many other regions over our forecast period, alongside different energy sources. The Middle East is forecast to add about 115 TWh of solar PV, while at the same time gas-fired output rapidly rises to displace oil-fired generation. Central and South America is similarly expected to post about 110 TWh of solar PV generation growth out to 2030, alongside significant increases in wind generation. Southeast Asia is set to see more than 35% of additional demand met by coal and close to 35% by gas, while 15% (65 TWh) is expected to be met by solar PV. In Africa, close to 28% (55 TWh) of the additional supply is expected to come from solar PV, alongside significant growth in gas-fired generation, followed by expanding hydropower, wind and nuclear output.

The strong growth of weather-dependent variable renewable energies and their rising share in many power systems during our forecast period further underscores the importance of system flexibility. Accompanying these technologies with flexible supply, storage and demand response, as well as interconnections where possible, will be crucial for their cost-effective system integration. These aspects are discussed more in detail in the following dedicated Grids and Flexibility chapters of our report.

Grids

Grids are emerging as a bottleneck for connecting supply, demand and storage

A lack of grid capacity is emerging as a critical bottleneck in many regions, driving higher levels of congestion and slowing the deployment of new electricity generation, storage and demand. Grid connection queues have reached record levels worldwide. In response, this year's report examines the range of measures that regulators and system operators are adopting to "move fast and connect things": enabling more capacity to be integrated more quickly through regulatory reforms and deployment of technologies that can deliver rapid grid upgrades. Greater demand-side participation and the expansion of utility-scale battery storage are additional levers for enhancing system flexibility and managing congestion, which are addressed in detail in the subsequent chapter on Flexibility.

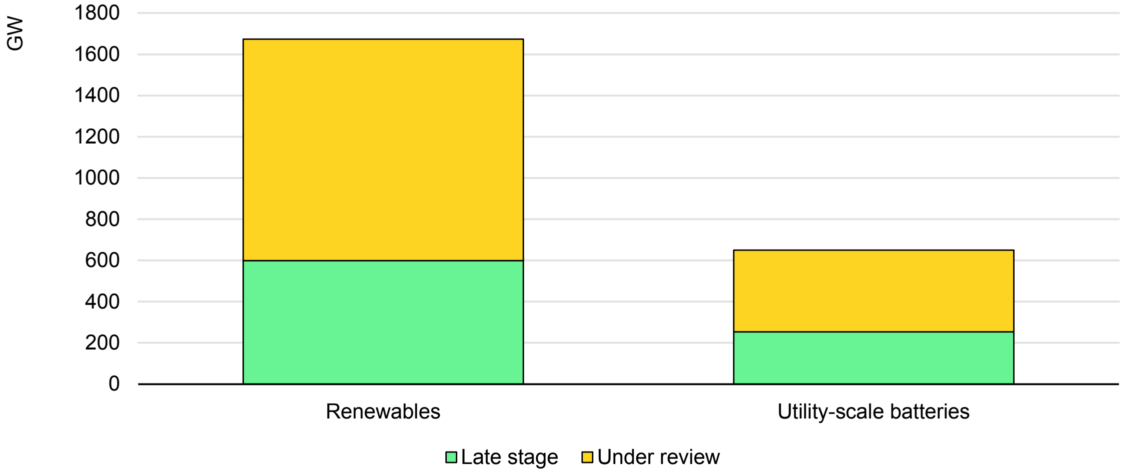
This chapter on grids also includes a dedicated section on the synchronisation of the Baltic power system in February 2025, a landmark technical and political achievement.

Grid technologies and regulatory reforms unlock grid capacity

Accelerating the build out of grids is a key imperative as the new era of electricity evolves around the world. Over 2 500 GW of renewable, large-load and storage projects are currently stalled in grid queues worldwide. With grid investment lagging far behind that for generation projects, many power systems already face rising congestion-related curtailment. Meeting electricity demand through 2030 will require annual grid investment to increase by approximately 50% by 2030 from today's USD 400 billion, alongside a scale-up in grid supply chains and more effective management of work force challenges.

The urgency becomes especially apparent given the mismatch in the time required to plan and build new grids compared to generation projects or data centres. Planning, permitting and completing new grid infrastructure can take anywhere from 5 to 15 years, whereas new builds on the supply and demand side are much faster at 1-5 years for renewables projects such as solar PV and wind, 1-3 years for data centres, and 1-2 years for EV charging infrastructure. At the same time, prices for key grid components have nearly doubled over the past five years.

Renewable energy and utility-scale battery capacity in advanced stages waiting in connection queues globally, by project stage, 2025



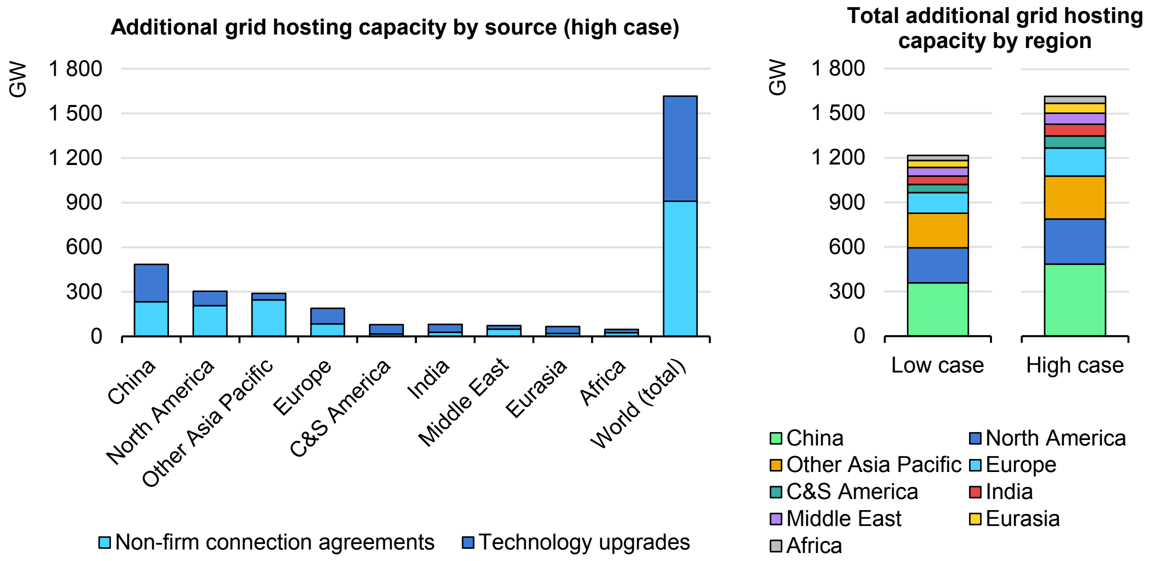
Notes: Late stage refers to projects at advanced stages of the grid connection process with a high likelihood of completion. Grid connection queue numbers can shift from month to month with project progress, cancellations, and operator reassessments. Data presented here should therefore be regarded as indicative for 2025.

While ramping up investment in the construction of new grids is crucial and needs to accelerate, significant additional hosting capacity[1] can be unlocked in the near term by using existing grids more efficiently. This is especially relevant, as grids are built to serve peak demand, but often have substantial unused capacity during non-peak periods.

Complementary measures, such as grid-enhancing technologies and regulatory adjustments, can unlock near-term grid capacity, delivering net system-wide economic benefits. Together, they could free enough hosting capacity to connect between 1 200-1 600 GW of advanced-stage projects currently stuck in queues worldwide. About 750-900 GW could be enabled through conditional non-firm connection agreements, with the remainder unlocked by grid-enhancing solutions such as dynamic line rating, advanced power-flow control, and various other options, as well as more extensive upgrades such as reconductoring and voltage uprating.

[1] Hosting capacity refers to the amount of new resources (generation, storage or load), in GW, that can be connected to the grid safely and reliably before system upgrades are required to avoid issues such as reaching operational limits or violating safety constraints. Hosting capacity can also include non-firm capacity, i.e. for which output or consumption may be limited at certain times.

Estimated grid hosting capacity that can be unlocked via non-firm connection agreements and technology upgrades by source (left), and by region (right), 2025



Notes: C&S America stands for Central and South America. The calculation of unlocked capacity via non-firm connection agreements is based on the assessment of public statements by system operators, regulators and governments in markets where this type of contract has already been implemented, taking into account power system characteristics and indicative levels of congestion. Technology upgrades considered are dynamic line rating, dynamic transformer rating, advanced power flow control, topology optimisation, storage as a transmission asset, reconductoring and voltage uprating. The calculation of unlocked capacity via technology upgrades is based on review of expert papers, reports, statements and case studies providing quantitative assessments of unlocked capacity and technical/economic viability by solution across a diverse range of transmission networks worldwide. For both non-firm connections and technology upgrades, potentials of unlocked capacity by region and globally have been calculated using existing country- or region-level transmission grid length by voltage range, conductor types, current rating, number of circuits, congestion, average and peak demand. Hosting capacity values are provided as a high-level estimation based on transmission capacity gains and can differ from real-world applications based on grid- and project-specific detailed connection studies to verify constraints which are not considered in this analysis, e.g. voltage, short-circuit, substation capacity, generation and load profiles, among others.

A non-firm connection agreement is an arrangement between a system operator and the grid user (such as a generator, consumer, or storage facility) that typically enables faster grid access, but with the condition that the user's output or consumption may be limited at certain times. This built-in flexibility helps unlock additional hosting capacity by allowing more assets to connect before major grid reinforcements are completed.

Beyond non-firm connections, standard congestion-management tools and robust regulatory frameworks that support the co-location of multiple power plants and battery energy storage systems (BESS) at a single connection point can further ease grid constraints. By enabling several assets to share existing infrastructure, these measures help bring more projects into operation in a timely manner.

In parallel, grid capacity auctions, stricter requirements for obtaining and retaining grid capacity, and faster processing of connection requests can contribute to more effective management of grid connection queues. These mechanisms help ensure that scarce capacity is allocated efficiently, prioritising the highest-value and most deliverable projects while reallocating capacity from projects unlikely to proceed.

In addition to targeted regulatory and policy measures, unlocking the full potential of today's power networks will increasingly depend on the deployment of advanced grid-enhancing technologies. These solutions can increase grid flexibility, ensure greater reliability and help reduce overall investment costs by relieving different types of binding operational constraints and improving utilisation of existing assets. Grid-enhancing technologies such as dynamic line rating (DLR), dynamic transformer rating (DTR), advanced power flow control (APFC), topology optimisation (TO), and storage as a transmission asset (SATA) will also play a key role in expanding existing capacity. In addition, more substantial upgrades to grid systems such as reconductoring and voltage uprating, can significantly increase the capacity of existing transmission infrastructure.

Record-high connection queues and rising curtailment as grids become congested

Globally, at least 1 700 GW of renewable energy projects in advanced stages[2] and more than 600 GW of battery storage projects were in connection queues as of 2025. A similar situation can also be observed on the demand side, where at least 150 GW of queued data centre projects are estimated to be in advanced stages. One-fifth of the global data centre build out is at risk of delay due to grid congestion. In addition, a significant amount of EV charging infrastructure, battery storage plants, and large industrial or other commercial loads are also waiting to be connected in highly congested regions.

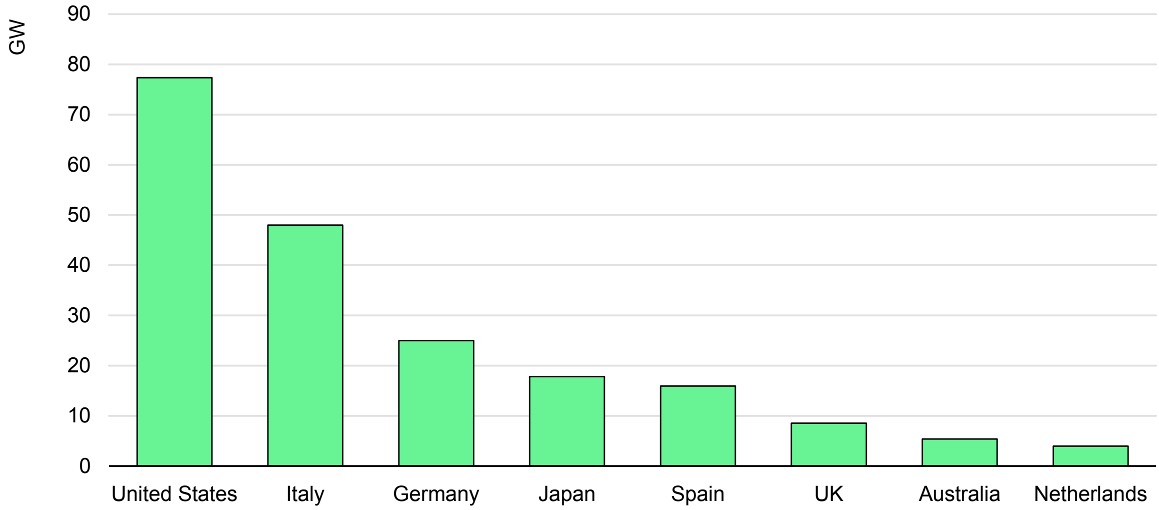
Lengthy grid connection queues are increasingly becoming a detrimental factor for a wide range of grid users. In some countries, such as Germany, these queues have already become a chokepoint for battery-storage deployment. The federal regulator (BNetzA) noted that in 2024 alone, network operators received 9 710 connection requests for battery storage at or above medium-voltage level, corresponding to around 400 GW (661 GWh) of capacity. Network operators caution that a significant portion of these projects are "phantom" projects, including speculative and duplicative requests.

Many countries face over-reservation of capacity in their connection queues through duplicate or phantom projects. This happens when project developers deliberately reserve capacity in excess of project needs or maintain connection requests for stalled projects, leading to inefficiencies in allocation processes,

[2] Projects at advanced stages include projects at late stages in their connection requests and those that are under review. It excludes projects that are at early stages of the process as well as those that are unlikely to materialise.

blocked access for more viable projects in the queue, and uncertainty in network planning. Regulators and system operators are adapting their mechanisms to limit the consequences of this virtual grid saturation phenomenon, with an overview of the measures being implemented provided in various parts of this chapter.

Capacity of utility-scale battery storage projects in late stages in connection queues in selected countries, 2025

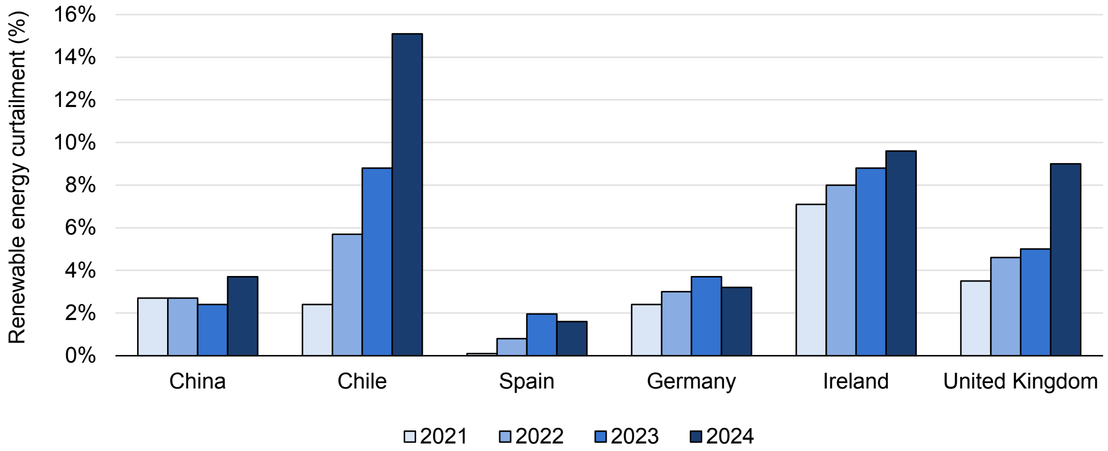


Notes: Late stage refers to battery storage projects at advanced stages of the grid connection process with a high likelihood of completion. Grid connection queue numbers can shift from month to month with project progress, cancellations, and operator reassessments. The figures presented here should therefore be regarded as indicative for 2025.
Sources: IEA (2025), Renewables 2025, and IEA analysis based on data from Terna (2025), Bundesnetzagentur (2025), METI (2025), and ESS News (2025).

In parallel with queue-management challenges, operational data show that grid bottlenecks are already limiting output through increasing curtailment. With rapidly expanding variable renewable energy (VRE) capacities, technical curtailment[3] due to grid bottlenecks has been rising in many regions. In the United Kingdom, 8.5% of onshore wind generation was curtailed in 2024, up from 8% in 2023 and 6% in 2022. In Chile, 15% of wind and solar PV generation was curtailed in 2024, the highest rate observed since 2017. In Germany, rates for wind (both onshore and offshore) were above 5% since 2022, while solar PV also started to gradually increase, rising to 2% in 2024. In China, 4.1% of wind generation and 3.2% of solar PV generation were curtailed in 2024, up from 2.7% and 2%, respectively, in 2023. Preliminary data for 2025 suggests that curtailment rates in China rose above 5% for both wind and solar.

[3] Technical curtailment is the dispatching-down of renewable energy for network or system reasons; dispatched-down energy due to economic or market conditions is not included.

Evolution of technical curtailment rates of VRE in selected countries, 2021-2024



Notes: VRE = variable renewable energy. Figures represent the share of total solar PV and wind energy potential that is technically curtailed. Figures are based on officially reported curtailed or constrained energy generation and combine various schemes, depending on the country. VRE refers to solar PV and wind unless otherwise specified. The United Kingdom includes wind only. Technical curtailment is the dispatching-down of renewable energy for network or system reasons; dispatched-down energy due to economic or market conditions is not included.

Source: IEA (2025), Renewables 2025.

VRE curtailment implies unused low-emissions energy. Depending on market specifics, high levels of curtailment can lead to sizeable losses of revenue for generators. It can also lead to higher CO_2 emissions from power generation if predominantly fossil-fuel-fired plants are dispatched in the redispatch process, notably to solve technical constraints, as highlighted in the IEA's Integrating Solar and Wind report. In systems with high levels of VRE penetration, particularly with structural oversupply at times such as midday solar PV peaks, keeping curtailment close to zero as a policy decision may lead to higher system costs, compromising the cost-effectiveness of the system. Additionally, allowing for some curtailment may enable more of the capacities in connection queues to be connected at a faster pace while the grid expansion takes place. Addressing curtailment, grid congestion and new connections in a cost-effective way requires a joint assessment of these factors, where the underlying factors such as transmission capacity, VRE penetration, demand structure and available flexibility, among other relevant aspects, need to be taken into account.

More efficient use of grids is possible via targeted regulatory and policy frameworks

In the short term, several regulatory mechanisms can help optimise the use of existing grids, reduce congestion, and unlock significant additional capacity. These include various types of non-firm connection agreements, congestion management tools such as redispatch, and co-location of multiple power plants or battery energy storage systems. In addition, managing grid connections through measures such as grid capacity auctions and stricter eligibility requirements can increase the efficiency of the connection system by prioritising the highest value projects, and de-prioritising others that are unlikely to be completed.

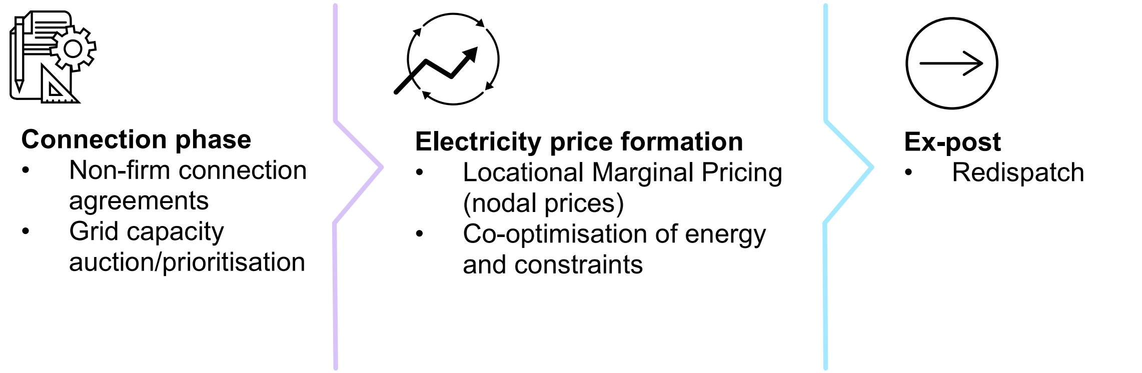
Non-firm connections can unlock near-term grid capacity, but complexities need to be well-managed

We estimate that application of non-firm connection agreements alone could free up enough grid hosting capacity to integrate 660-860 GW of projects in connection queues globally, while grids are being expanded. Historically, most connection agreements between grid operators and energy suppliers have been firm connection contracts, where the end user has an allotment to withdraw or inject energy up to a fixed power level, which is typically dimensioned to match the size of the equipment on site. The grid user is allowed to reach this static limit whenever they wish, under normal conditions without congestion. Traditionally, congestion problems have been rare, but have increased in recent years in many regions. When the transmission or distribution network is congested, countries use a variety of management mechanisms to adjust the output of assets. These include redispatch and security constrained economic dispatch (SCED), generally with compensation to assets impacted by the constraints, socialised across grid users.

While redispatch and SCED measures take place during the operational stage, non-firm connection agreements are established earlier, during the planning phase, typically before the asset is connected. These are agreements between a grid operator and a grid user, detailing how usage can be limited[4] during times of congestion, based on different arrangements and conditions. While the operator benefits from having more visibility and control over grid usage to mitigate constraints, the user may benefit from a faster grid connection, lower connection charges or reduced grid tariffs. During the operational stage, when curtailment is required, the operator typically restricts the production or consumption of users with non-firm agreements. Users with firm agreements are normally curtailed only after all suitable users with non-firm agreements are curtailed. Compared to a user with firm connection, the non-firm connected user typically receives no compensation during this phase because they have agreed to bear curtailment risk, depending on the arrangements.

[4] Non-firm connection agreements are only used to limit a load's consumption or a generator's output. In contrast, redispatch and SCED adjustments are not always a reduction. Depending on the grid conditions and where the grid users are located, they may also be ordered to increase production/consumption to relieve congestion.

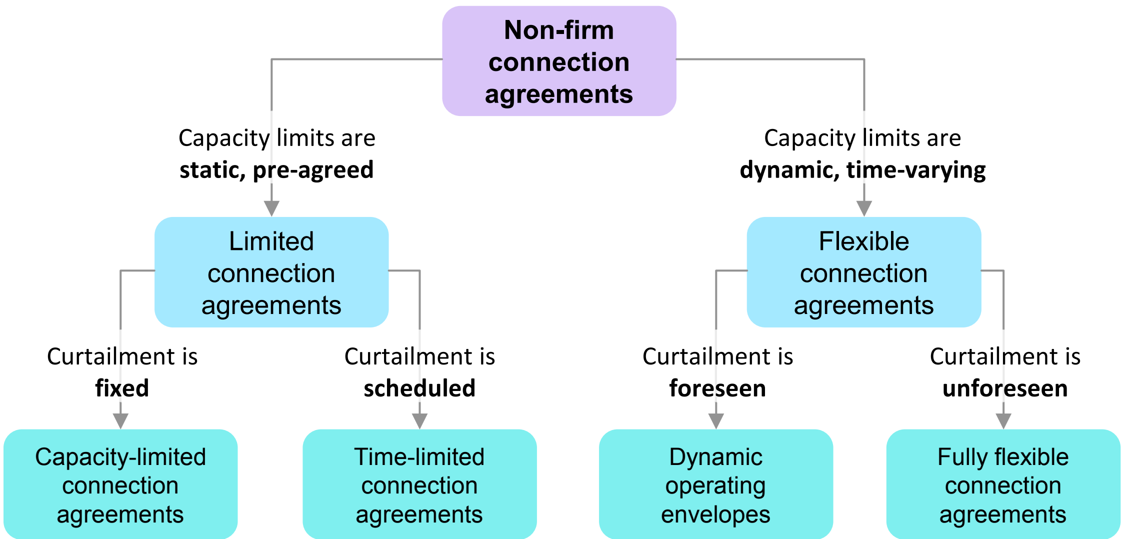
Timeline of measures and market structures for managing grid congestion



Notes: The effects of some measures and structures may extend across the temporal boundaries shown. Non-firm connection agreements are signed during the planning phase, but the decision about when to curtail the grid connection may be made dynamically during later phases. Other tools such as locational marginal pricing can influence siting decisions in the planning phase, as investors anticipate the impact of location on revenue.

Different types of non-firm connection agreements exist, and similar arrangements may be referred to by different names across jurisdictions. However, they can generally be categorised by two key features: whether their capacity limits are fixed or dynamic, and whether curtailment is foreseen – such as in scheduled or predictable operating envelopes – or unforeseen, as in fully flexible arrangements. These approaches are increasingly being codified through legislation or regulatory guidance across countries, supported by digital monitoring tools and closer integration with local flexibility markets.

Examples of types of non-firm connection agreements based on the temporary variability of capacity limits and the predictability of curtailment



Source: Adapted from Romero Monterde et al. (2025), "Non-Firm Grid Connections: A Review of Access Types, Mechanisms, and Regulatory Frameworks", Current Sustainable/Renewable Energy Reports, CC BY 4.0.

While non-firm connection agreements can provide substantial benefits in providing faster grid connections until the grid expansion takes place, they can also introduce complexities related to grid utilisation, curtailment uncertainty and fair allocation of costs across different grid users. Introduction of such agreements therefore requires a thorough assessment of market conditions (including the extent of unbundling) and the associated trade-offs. The broader adoption of non-firm connection agreements may require addressing such complexities. Well-defined, harmonised regulatory frameworks, supported by interoperable digital systems, can play a central role in ensuring consistent application across jurisdictions.

When considering non-firm agreements, grid users such as generators, storage operators, and consumers, may need to assess the trade-off between the benefits of an earlier commencement date and lower grid fees, with a reduction in revenues when curtailed. For time-varying capacity limits, projects may additionally need to consider any potential correlation between curtailment periods and high price events, which may lead to disproportionate reductions in revenue during price spikes.

For periods with congestion, a grid operator may need to choose which of several assets with non-firm connection agreements must have its output adjusted. There are several methods for such prioritisation. Last In, First Out (LIFO) is used by the UK's National Grid, whereby the most recently connected asset is the first to be curtailed. Another approach is a curtailment index, which is used to target an equal number of hours of reductions or equal forgone energy per asset, in the long run, potentially weighted by generator size. Alternatively, reductions could be applied to the generator/load with the highest/lowest energy bid first to minimise the cost of congestion. If all assets had non-firm connection agreements, prioritising by their energy bid price would be similar to security constrained economic dispatch (SCED), such as the Electric Reliability Council of Texas (ERCOT) and Australia's NEM[5]. Whereas prioritising based on a dedicated congestion bid would be similar to market-based redispatch. Non-firm connection agreements can be used to manage distribution level constraints, whereas alternatives such as SCED commonly consider only transmission level constraints.

Regulatory frameworks are being updated to allow for more efficient usage of grids

An array of non-firm connection agreements are being implemented in a bid to optimise excess grid capacity to manage new customers. In the **European Union** Directive 2024/1711 mandates regulators to develop a framework for system

[5] The equivalency depends on whether assets impacted by congestion are compensated. In ERCOT they are, in Australia's NEM they are not.

operators to offer flexible connection agreements (FCAs) in cases where there is limited or no network capacity available. This acts as a temporary measure until network reinforcements are developed or as a permanent measure where network reinforcement is not efficient. The European Grids Package, launched in December 2025, included a Guidance on Efficient and Timely Grid Connections, which also highlights the need for offering frameworks for FCAs. Several EU countries have transposed this into existing legislation or proposals to be adopted in coming months, and 15 members have already implemented FCAs as of November 2025.

The **Netherlands** Authority for Consumers and Markets (ACM) regulator is requiring system operators to use the existing grid more efficiently by applying congestion management procedures as well as by introducing new tariffs and non-firm contract types to encourage flexibility and lower peak-hour consumption. With the new rules, transmission system operator (TSO) TenneT estimates that 9 GW of hosting capacity will be freed up, enabling a significant number of customers to be connected. As of April 2025, more than 70 GW of projects had applied for this type of contracts, in large part because they provide accelerated grid access and no charge for the contracted capacity, resulting in a tariff discount up to 50%[6].

In **Denmark**, grid operators offer FCAs for new generation and demand requests, with accelerated connection and reduced connection costs. Under the agreement, large loads can be disconnected or ordered to decrease load at any time in case of constraints.

In **France**, transmission operator RTE estimated that optimal grid-connection sizing for VRE generators through static non-firm connection agreements, which have been in place since 2021, unlocked 18 GW of hosting capacity in four years.

In **Ireland**, ESB Networks estimated that up to 1 GW of capacity could be connected to the grid by extending non-firm connection agreements.

The **United Kingdom's** National Grid offers flexible and curtailable connection agreements in congested areas, both for generators and loads, through its Active Network Management (ANM) system. The UK government expects regulatory and system operator-led connection reforms across transmission and distribution to release around 100 GW of capacity from queues, more than is currently connected to the transmission network.

In **Japan**, non-firm connection agreements are systematically applied to generators intending to connect to the grid, regardless of whether the area has

[6] The discount can reach 65% if a grid user both responds to the new time-of-use network tariff on top of benefiting from the non-firm discount.

capacity available. By October 2024, this type of connection request reached 26 GW nationwide. However, mandatory frameworks have faced opposition in other markets.

Grid access is being prioritised via queue management and grid capacity auctions

In order to manage the grid connection queues more effectively, various new measures are being introduced in many countries. Broadly, reform proposals across several jurisdictions often include prioritising projects based on maturity, likelihood of realisation, and expected contribution to system needs, using predefined technical criteria or, in some cases, price-based mechanisms, rather than the timing of application submissions. In addition to overall grid connection queue reforms, separate frameworks for large loads are also being developed in some countries.

One type of regulatory development includes prioritisation frameworks for connection queues, namely replacing the traditional 'first-come, first-served' principle in favour of 'first-ready, first-served' or milestone-based approaches. The Dutch regulator ACM, for example, is working on establishing a framework with three categories whose grid connections will be prioritised: the so-called "congestion softeners" that provide additional capacity are given the highest priority, followed by projects contributing to national security, including hospitals, and basic needs such as residential, education and public transport.

German TSO Amprion introduced a EUR 50 000 processing fee for connection applications and reported that 65% of battery projects in its queue were not being pursued further. The existing first-come, first-served connection regime without additional prioritisation criteria risks delaying more mature projects behind less developed ones, adding to the backlog and increasing uncertainty for project developers. Against this backdrop, TSOs such as 50Hertz have called for new allocation procedures, arguing that the current approach no longer reflects the needs of the energy transition.

In the United States, only 8% of battery storage projects that applied for connection between 2000 and 2019 had been built by the end of 2024, though projects that are insufficiently developed may inflate such queues. Withdrawals are frequent, particularly when restudies change upgrade scopes or connection dates. Historically, this was worsened by speculative or duplicate applications, which prompted reforms such as FERC's Order No. 2023 that introduced stricter readiness requirements to discourage this behaviour. For example, developers must now demonstrate clear rights to develop at least 90% of the land at the time of interconnection request, meaning legally enforceable rights to occupy and develop the land, such as ownership or a lease, and submit a commercial-readiness deposit.

In addition to queue management, networks and regulators are focusing on approaches to accelerate and streamline the process on the approver side when processing the projects in the queue. MISO in the United States automated part of their System Impact Study, which they expect will reduce processing times by a factor of eight. Australia imposed strict time limits on the response time from AEMO and networks, reduced friction for small or sensible changes, and made changes to avoid holding generators responsible for changes outside their control. Similarly, the United States recently started imposing penalties on transmission providers that fail to complete studies before newly imposed deadlines. China has introduced a “green channel” to accelerate the planning and construction of 500 kV+ transmission corridors for key clusters of new renewable generators under a framework where generation and network infrastructure are tightly co-ordinated. Similarly, upgrades of lower voltage lines are also being streamlined. On the load side, China’s “Three Provinces” policy streamlined connections for large loads, reducing connection time by more than 40%. For small load connections, the “Three Zeros” policy reportedly contributed to saving CNY 300 billion (Yuan renminbi), [USD 43 billion], over the last five years.

Separately to existing capacity markets for generation itself, some jurisdictions are introducing new auctions to allocate grid capacity. In Australia, the South West Renewable Energy Zone Access Scheme was introduced in 2024, which allocates capped grid capacity via tenders for grid access for VRE and storage. Romania recently launched nationwide grid capacity auctions for VRE and storage. Meanwhile, Spain introduced auctions for connecting large loads.

Examples of recent regulatory and policy developments in securing grid capacity and connecting generators, storage and large loads

Regulation Type	Country	Title	Scope	Description
Non-firm connection agreements	Netherlands	Time-Dependent Transport Rights (TDTR)	Load and storage	Full capacity guaranteed 85% of time, 15% flexible.
	United Kingdom	Active Network Management (ANM)	Generation, storage and load	Controls assets, prioritising older assets over newer.
	Japan	Non-firm connection rule	Generation and storage	Controls assets connected to the local bulk grids with less available capacities.

Regulation Type	Country	Title	Scope	Description
Milestone-based project development	United Kingdom	Gate 2 to Whole Queue (G2TWQ)	Generation and storage	Readiness criteria for joining the queue and network studies are batched.
	United States (MISO)	Definitive Planning Phase (DPP)	Generation and storage	Connection applications must reach key milestones, otherwise they will be forcefully withdrawn, with loss of deposit.
Site-dependent connection tariff	United Kingdom	Transmission Network Use of System Charges (TNUoS)	Generation, storage and load	Deeper, more localised and less volatile network charges reflecting planned grid availability.
	India	Inter-state transmission charge exemption for ESS	Storage	No inter-state transmission charges for batteries co-located with VRE.
Grid capacity auction or prioritisation	Australia, NSW	Southwest Renewable Energy Zone Access Scheme	Generation (VRE) and storage	Tenders for grid access rights for VRE and batteries.
	Romania	Grid Allocation Market	Generation and storage	Auctions 10-year grid connection.
	Chinese Taipei	Grid Capacity Allocation for Offshore Windfarms	Generation (Offshore windfarms)	Allocates 15 GW of grid capacity based on the lowest PPA price.
	Spain	Grid Access Tender	Loads	Allocates 3.7 GW of grid capacity, prioritised based on biggest carbon reduction.
	United States (CAISO)	ISO Interconnection Reforms	Generation and storage	Prioritisation of a capped connection queue, based on commercial interest, project viability, and system need.
Connection assessment fast-track or streamlining	Netherlands	Prioritisation Framework	Storage and load	Prioritise “congestion softeners” first, then “security” (e.g. hospitals, policy stations), then “basic needs” (e.g. schools, public transport).
	United States (MISO)	Expedited Resource Additions Study (ERAS)	Generation and storage	Expedites grid connection request reviews for 5.3 GW of selected assets.

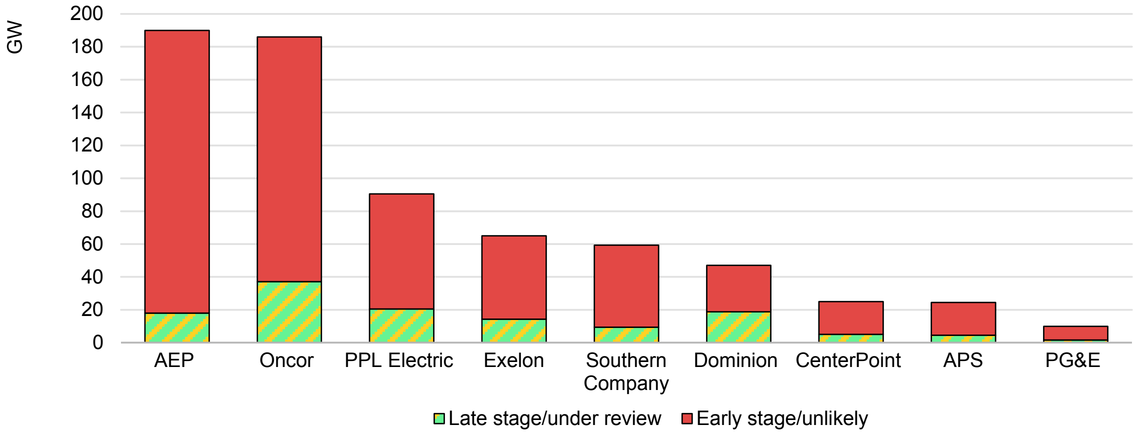
Regulation Type	Country	Title	Scope	Description
Connection assessment fast-track or streamlining (continued)	United States (MISO)	Definitive Planning Phase (DPP)	Generation, storage and load	Automated System Impact Study, reducing time taken from months to days. Total queue length is capped.
	China	Green Channel	Network	Accelerated approvals for select network upgrades for new renewables.
	Australia (NEM)	NEM access standards Package 1	Generation, storage and network	Streamlines technical requirements for grid connection application for VRE, batteries, synchronous condensers and HVDC.
	Australia (NEM)	R1 Capability Assessment	Generation and storage	Streamlines approvals, and shift risks from generation/storage to the network. Imposes time limits for responses from networks, and mandates justifications for requests for more information.
Large load framework	United States	Department of Energy (DOE) Ensuring the Timely and Orderly Interconnection of Large Loads	Generation, storage and load	Expedites grid connection studies, enables joint studies for generation-load co-location and large loads to share upgrade costs.
	United States (SPP)	High Impact Large Loads (HILLs)	Load	Accelerated pathway for large loads agreeing to FCA or paired with generation.
	United Kingdom	AI Growth Zone	Load	Removes speculative data centre demand and reallocates grid capacity to prioritised AI data centres.
	Canada (AESO)	Large Load Integration	Load	Reliability-based grid access limit and technical requirements.
	China	Notice on Improving Renewable Integration for High-Quality Development	Generation, storage and load	Co-optimised planning of network and generator construction, and improved data sharing from networks to generators.

Specific large load connection frameworks prioritise viable projects and strengthen system planning

Large loads, and specifically data centres, play a key role in the growing connection queues in various regions. While the growth in cloud services and artificial intelligence partly explains these trends, similar to the situation with generation and storage assets, demand connection queues are artificially expanded by duplicative or phantom projects which are not expected to materialise. Our analysis based on data reported by utilities in the United States indicate a trend of only around 20% of the data centre connection requests materialising in the short to medium term. Similarly, in the case of Australia, the consulting company Oxford Economics, commissioned by Amazon Web Services (AWS), estimates that out of 44 GW of data centre connection requests, only 8 GW are likely to enter service. In Brazil, data centre connection requests surpassed 26 GW by November 2025, but according to Brazil's Energy Research Office (EPE) only 6 GW were under review or at late stages at that time.

Obtaining a realistic estimate of what part of the demand queue would accept a connection offer once capacity is available is key for regulators, system operators and utilities to accurately perform system planning and optimise investments and asset management. To identify which projects are viable and which projects should be filtered out from the queue, some countries are developing separate grid connection frameworks for large loads.

Data centres in connection queues by selected utilities in the United States, 2025



Notes: Grid connection queue numbers can shift from month to month with project progress, cancellations, and operator reassessments. The data presented here should therefore be regarded as indicative for 2025.
Sources: IEA analysis based on data from AEP (2025), Data Center Dynamics (2025), Oncor (2025), Utility Dive (2025), Industrial Info Resources (2025), Financial Times (2025), Data Center Dynamics (2025), Broadband (2025), Latitude Media (2025), Dominion Energy (2025), The Wall Street Journal (2025), Utility Dive (2025).

In the **United States**, large loads, including data centres, are already addressed through specific processes in many areas, as generation and grid expansion plans are closely linked to data centre connection requests. Nationwide, the Department of Energy (DOE) directed the Federal Energy Regulatory Commission (FERC) in October 2025 to initiate procedures with the aim to reduce large load connection times and grid upgrade costs, while allowing joint co-located (generation and load) grid access requests.

In September 2025, the Southwest Power Pool (SPP) agreed a 90-day study and approval pathway for data centres and other large loads paired with generation or agreeing to a curtailable supply. In California, PG&E introduced Electric Rule 30 reducing large load connection timelines from 18-22 months to around 2-5 months for applicants that agree to pay for necessary transmission infrastructure work upfront.

ERCOT was one of the first US independent system operators (ISOs) to develop an interim large load interconnection process in 2022, and this was updated in May 2025 via the Nodal Protocol Revision Request 1234. The new ERCOT protocol establishes more stringent modelling and study requirements, and a dedicated interconnection process with a new fee, aiming to accelerate the pathway for viable projects and filter out speculative requests from the growing queue.

In addition, utilities across the United States are developing specific frameworks for data centres, focused on discouraging speculative/duplicative large load interconnection requests and securing long-term revenue for the allocated grid capacity. Dominion Energy Virginia proposed a new rate class for high energy users, in which they are required to make a 14-year commitment to pay 60% of generation costs and 85% of network costs even if they use less power than they applied for. Other utilities have increased large load application deposits, as is the case of ComEd in Illinois, which charges a USD 1 million refundable deposit for data centre requests of 50 MW or more.

European regulators and system operators are also adapting their policies to effectively deal with large loads within their growing demand interconnection queues. In December 2025, the Irish regulator CRU published a specific large energy users connection policy requiring, among other measures, that all new data centres connecting to the grid provide dispatchable generation and/or storage capacity, matching the site's maximum import capacity. In addition, they must source at least 80% of annual demand from renewable electricity generated in Ireland. EirGrid has restricted data centre connection in the greater Dublin area since 2021 due to congestion. Elia, the Belgian TSO, could set a cap on data centre capacity allocation based on its own grid development plans, limiting data centre expansion and keeping some capacity available for other types of industrial users.

The UK government has introduced the AI Growth Zones regulatory package to accommodate rising grid connection requests from large 'AI data centres' of 100-500 MW capacity. Under this framework, AI data centres are prioritised for grid access and allowed to reserve certain physical connection points, if they are considered "strategically important." The package aims to accelerate the interconnection of viable AI data centres by filtering out speculative requests, while enabling project developers to build their own grid infrastructure, including high-voltage lines and substations.

As data centres strive to get deployed without delays, an emerging trend in regions where grid connections or insufficient baseload capacity are becoming bottlenecks is for data centres to secure behind-the-meter (BTM) supply through on-site generation assets. Given their high reliability requirements as well as depending on regulatory frameworks, many data centres can choose or be required to stay connected to the grid despite having sufficient BTM generation.

Various market-specific structures or processes can inherently help manage and reduce congestion

There are also other market structures or processes which can help with managing and reducing congestion by design. Security constrained economic dispatch (SCED) ensures that transmission constraints between price regions are directly incorporated into the bid clearing process. Increasing the geographical granularity of prices increases the number of constraints considered in this way. By disaggregating prices into several zones per country (such as in Italy and Sweden), key transmission bottlenecks can be incorporated into bid clearing. Sub-national zonal prices can thus help with congestion, while additional congestion management mechanisms can be applied at the same time.

Locational marginal pricing can be further disaggregated to more granular nodal pricing (e.g. ERCOT, California Independent System Operator (CAISO) and PJM in the United States, and markets in Chile, Mexico, New Zealand). Prices on either side of a constraint diverge and constrained bid clearing results in power flows which satisfy the constraint, implicitly rewarding generation, storage and load, which relieve the constraint. Disaggregating pricing further into distribution level nodes is generally not common and may be infeasible, so other congestion management mechanisms may still be used for distribution level constraints. The potential benefits as well as various challenges associated with more granular locational price signals are discussed in detail in the IEA's Electricity Market Design report.

Some markets, including Australia and the Philippines, use hybrid approaches in which intra-regional transmission constraints are incorporated directly into the market-clearing process that matches supply and demand to determine prices and dispatch targets. This produces location-specific prices used for dispatch decisions, similar to nodal pricing. However, all generators and loads within a region ultimately settle at a single regional price. As a result, power flows respect transmission constraints by adjusting the highest-bid generators first, without requiring a separate congestion payment mechanism.

Various market and system structures that can indicate which assets should be adjusted first during congestion

Market-based

- **Locational Marginal Pricing (Nodal Prices)** (e.g. New Zealand, PJM, ERCOT, Chile, Mexico, MISO, CAISO)
- **Co-optimisation of energy and intra-region transmission constraints** (e.g. Australia (NEM), the Philippines)
- **Market-based Redispatch** (e.g. the Netherlands)

Rule-based

- **Cost-based redispatch** (e.g. Germany)
- **Non-firm connection agreements:**
  - Last In First Out (LIFO) (e.g. UK National Grid)
  - Proportional to size (e.g. New York National Grid)
  - Fraction of quota hours remaining (e.g. UK Electricity North West)

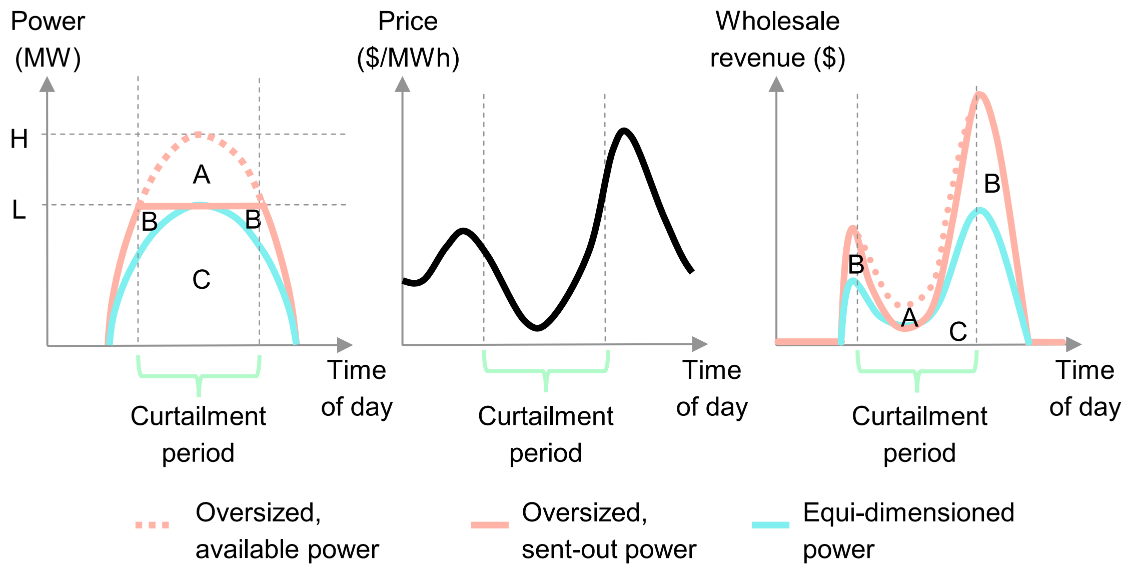
"Oversizing"[7] is another approach that can make grid connections more economically efficient while enabling the connection of greater capacities of variable renewable energy. In a common situation without oversizing, renewable assets are connected to the grid with a connection that is rated for the generator's maximum capacity. With oversizing, the generator's maximum capacity is larger than the available grid capacity, effectively capping the generator's maximum feed-in into the grid. While the system outcome would be typically equivalent to that of a fixed capacity-limited connection agreement between a grid operator and a grid user, oversizing is a design choice that would be taken by the project developer.

Although oversizing results in lower generated electricity volumes compared to having a larger connection, the average market value of each unit of electricity fed into the grid is higher. This is because the periods when an oversized VRE generator must leave sunshine or wind unused are generally when it is most plentiful, which is correlated with low prices. The increase in revenue from

[7] "Oversizing" is also commonly referred to as "overplanting".

oversizing compared to a smaller installation may offset the increase in cost, resulting in higher system value. The system value can improve further when solar and wind are co-located, as their complementary generation profiles make better use of shared grid infrastructure. Integrating batteries can also provide additional benefits when faced with limited grid connection availability.

Conceptual explanation of oversizing trade-offs in the example of a solar PV plant



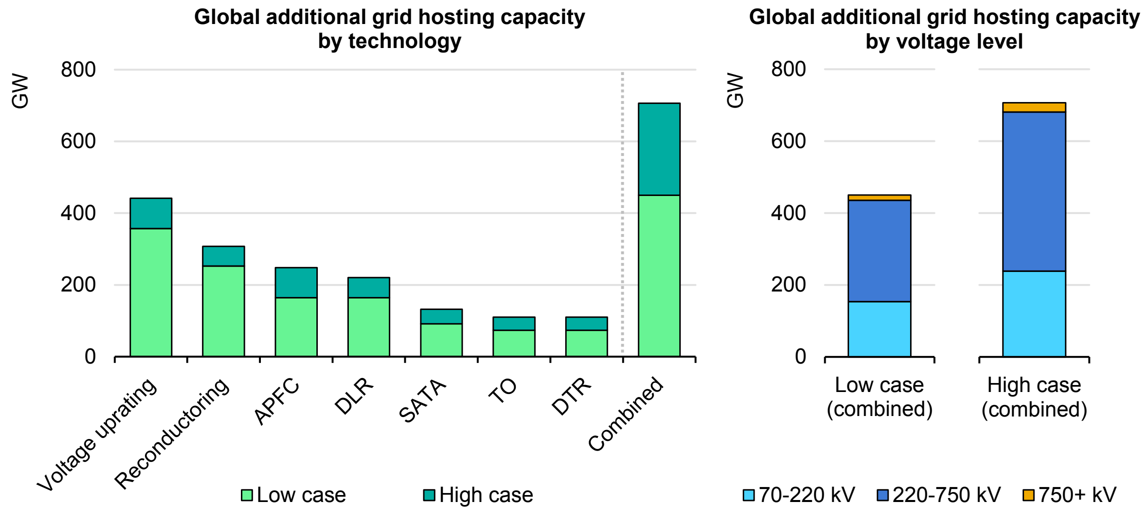
Notes: The chart shows an example of a grid connection that is smaller than the maximum output of the connected "oversized" generator, so some potential power must remain unused. Suppose a solar project developer wants a grid connection of size H. However, they are only able to obtain a grid connection of size L. They can choose to install fewer solar panels to match this lower limit (equi-dimensioned) to avoid any restriction below available power. Alternatively, they could install the larger number of panels as per the original plan, and then restrict the output to size L, below the available power during the period when the connection constraint binds, foregoing area A. This oversizing approach will cost more to build than the equi-dimensioned approach, but yields additional energy and additional revenue (area B). In regions with high VRE penetration, the hours with bright sunlight and strong wind are typically correlated with low prices, because plentiful supply puts downward pressure on prices. Therefore, the additional energy (area B) may yield disproportionately high revenue, and a higher capture price, which might outweigh the increase in installation cost compared to the equi-dimensioned installation. The same trade-offs apply to wind power. These revenue and price curves have been stylised for visual clarity, and should not be interpreted as the exact shape.

In addition to the above-mentioned structures and mechanisms, demand-side flexibility (e.g. via services such as vehicle-to-grid) can also greatly help increase effective capacity on grids, allowing for more efficient utilisation. The topic of demand response is covered more fully in the following chapter on Flexibility.

Grid-enhancing technology unlocks capacity at relative low costs and with short lead times

Alongside updating regulatory frameworks, significant grid capacity can be also unlocked in the near term by applying various grid-enhancing technologies. In addition, upgrades like reconductoring and voltage uprating can significantly increase the capacity of existing transmission infrastructure. These solutions can enhance grid flexibility, ensure greater reliability and help reduce overall investment costs, and are already being applied across regions. We estimate that the implementation and rollout of these grid technology solutions globally could unlock sufficient capacity to connect 450-700 GW of projects at advanced stages in connection queues, assuming all other factors remain unchanged.

Estimated grid hosting capacity that can be unlocked globally through selected technology upgrades by technology and voltage level, 2025



Notes: The combined capacity increase is lower than the sum of individual technology contributions, as multiple grid-enhancing solutions often address the same binding constraints. As a result, capacity gains are not additive, and the effect of deployment in a combined application is lower than in cases where each technology is implemented on a standalone basis. The calculation of unlocked capacity via technology upgrades is based on literature review of papers, reports, statements and case studies providing quantitative assessments of unlocked capacity and technical/economic viability by solution across a diverse range of transmission networks worldwide. Potentials of unlocked capacity by region and globally have been calculated using existing country-level or region-level power grid length by voltage range, conductor types, current rating, number of circuits, congestion, average and peak demand. Hosting capacity values are provided as a high-level estimation based on transmission capacity gains and can differ from real-world applications based on grid- and project- specific detailed connection studies to verify constraints which are not considered in this analysis, e.g. voltage, short-circuit, substation capacity constraints, generation and load profiles, among others. Sources used to develop these methodologies are provided where relevant in the text below.

Most of the technology solutions described below can be deployed on the grid with relatively short lead times, replacing traditional grid investments or serving as temporary measures aligning short-term needs with long-term grid planning. While potential capacity gains are presented individually by technology, benefits cannot be stacked additively, as several solutions address the same thermal, voltage or congestion constraints. Realising these capacity gains also requires integrating these technologies into both strategic grid planning and operational planning processes, supported by appropriate regulatory frameworks that incentivize grid optimization and operational procedures that enable system operators to leverage the additional capacity effectively.

Global experience shows that after implementing **dynamic line rating (DLR)**, transmission lines can typically carry 20-30% additional capacity above their maximum rating for around 90% of the time in a given year, representing a largely untapped resource that can be mobilised relatively quickly. This additional capacity is weather-dependent rather than firm capacity, available when ambient conditions such as temperature and wind enable safe operation above static ratings. Our analysis shows that DLR systems alone could unlock 165-230 GW of additional global transmission capacity – an upward revision from our previous estimate, based on updated inputs and assumptions reflecting recent deployment experience. However, realising these benefits depends on the quality of weather forecasts, real-time monitoring capabilities, and the willingness of system operators to optimise line loading while maintaining adequate corrective remedial actions. The barriers to broader DLR adoption are predominantly institutional rather than technical, reflecting cautious operational cultures and lack of regulatory incentives for efficiency innovations, despite DLR's proven ability to safely increase transmission capacity.

An equivalent technology for transformers instead of lines is **dynamic transformer rating (DTR)**, which uses real-time monitoring of operational and ambient conditions to safely load transformers above their nominal rating without impacting its design life, freeing up latent capacity. Like DLR, DTR provides weather-dependent capacity rather than firm capacity. Recent case studies and literature show that the average safe rate of transformer overloading via DTR is around 10%, with significant variation by ambient temperature at the location, as colder climates allow higher overloading while warmer climates limit it. We estimate that DTR by itself could unlock 75-115 GW of non-firm grid capacity globally.

Topology optimisation (TO) software finds the optimal network configuration to relieve constraints and unlock capacity, by switching circuit breakers in substations. Recent case studies, mainly in the United States show that this technology can increase throughput in congested areas by more than 10%, reducing critical constraint flows and curtailment rates. We estimate that TO solutions can lead to 75-120 GW of additional global grid capacity when deployed individually.

Advanced power flow control (APFC) devices, a subcategory of flexible AC transmission systems (FACTS), can also unlock 165-260 GW of capacity globally and resolve network congestion issues by dynamically diverting flows from overburdened lines to others with available capacity. These modular power electronics-based devices achieve this by modifying the reactance of lines where they are deployed. In the United Kingdom, the targeted implementation of this technology in the highly congested area of Northern England led to over 2 GW of capacity being unlocked, or over 4% of Great Britain's peak load. Various APFC projects in Colombia have freed up more than 1.2 GW of capacity across its transmission network, or almost 12% of its peak load, increasing capacity in congested nodes by up to 80%.

Projects deploying storage as a transmission asset (SATA) have shown promising results in increasing capacity of the transmission grid by reducing spare line capacity kept for N-1 security. In Germany, the "Grid Booster" project was granted a permit in 2025, and should start operations in 2026. Instead of being operated at around 70% to leave headroom in case a parallel circuit trips, lines equipped with SATA can be operated much closer to the 100% thermal rating, as batteries alleviate overloads. The operational 300 MW/450 MWh utility-scale Victorian Big Battery project in Geelong, Australia has a grid services contract with AEMO and unlocks 250 MW of peak capacity on the existing Victoria to New South Wales Interconnector during the summer. By itself, SATA could provide around 95-140 GW of additional grid capacity globally.

As discussed in a recent IEA commentary, other grid-enhancing solutions include **reconductoring**, which corresponds to retrofitting lines with higher-capacity conductors to allow up to double power flows in the case of advanced conductors like High-Temperature Low-Sag (HTLS) conductors. Advanced conductors can be installed on existing towers and supporting structures, thereby avoiding full permitting procedures, reducing implementation time and costs. In the United States, over 70% of utilities have deployed advanced conductors at least on a limited basis, and around 20% of existing transmission and distribution lines are potential candidates for retrofitting, particularly short lines of less than 50 miles. The Speed to Power Initiative launched by the US DOE in September 2025 aims to accelerate generation and transmission projects to support demand growth, including reconductoring and using existing connection capacity from retired thermal generation plants. The initiative focuses on projects that can enable between 3-20 GW of incremental load individually. In the Netherlands, as part of its 'Making better use of the existing 380 kV grid' project, TenneT is reconductoring part of its high voltage (HV) grid, increasing ratings from 2.5 kA to 4 kA. Reconductoring, as an individual technology upgrade, could unlock 255-320 GW of firm capacity globally.

Voltage uprating to increase the voltage levels to boost capacity is another application, albeit costlier than other technology upgrades. This process typically involves replacing towers, insulators, HV equipment, transformers, and other components. It is often carried out to reuse existing transmission corridors, with the aim of shortening permitting timelines and reducing overall project complexity. Capacity in the concerned part of the grid increases with the nominal voltage uprate. In Ireland, for example, ESB Networks is upgrading its 10 kV medium-voltage network to 20 kV, quadrupling capacity and reducing system losses. National Grid is building three new substations in the centre of England which will enable the uprating of the existing transmission network in the area from the existing 275 kV to 400 kV. This will contribute to the additional 20 GW of capacity needed to transfer electricity between the North of England and the Midlands by 2035. Statnett, the Norwegian TSO, has also been upgrading part of its 300 kV networks to 420 kV for more than a decade that could result in savings of over USD 1 billion compared to new built HV lines. Globally, we estimate that grid firm capacity could be expanded by 360-460 GW through voltage upgrade of existing HV lines.

No single technology can alleviate system-wide congestion issues, therefore an appropriate combination of technologies tailored to local needs is required to provide the highest overall benefit. Achieving these benefits is possible together with calculated risk-based approaches to grid operation, backed by robust forecasting capabilities and appropriate corrective measures. At the same time, various other barriers may need to be overcome. Regulatory frameworks need to evolve to incentivise grid optimisation and to create structured pathways for moving from pilot projects to standard operational practice. For grid operators, developing internal expertise that bridges traditional power-system knowledge with emerging technological capabilities is essential in this context. Due to their strong focus on security, utilities and system operators may tend to be conservative regarding applying new technologies. Providing the necessary regulatory incentives for efficiency-related innovations can help with this.

Overview of grid technology upgrades and their characteristics

Technology	Capacity increase	Potential global coverage	Cost	Firm capacity	Implementation lead time
Dynamic Line Rating	20-30%	5-15%	$	●	1-2 years
Dynamic Transformer Rating	5-15%	5-15%	$	●	1-2 years
Topology Optimisation	5-15%	10-20%	$	●●	1-2 years
Advanced Power Flow Control	10-20%	10-20%	$$	●●	2-3 years
Storage As a Transmission Asset	30-40%	1-5%	$$	●●	2-3 years
Reconductoring	50-100%	1-5%	$$$	●●●	3-4 years
Voltage uprating	100-200%	1-5%	$$$$	●●●	4-7 years
New HV lines	-	-	$$$$$	●●●	7+ years

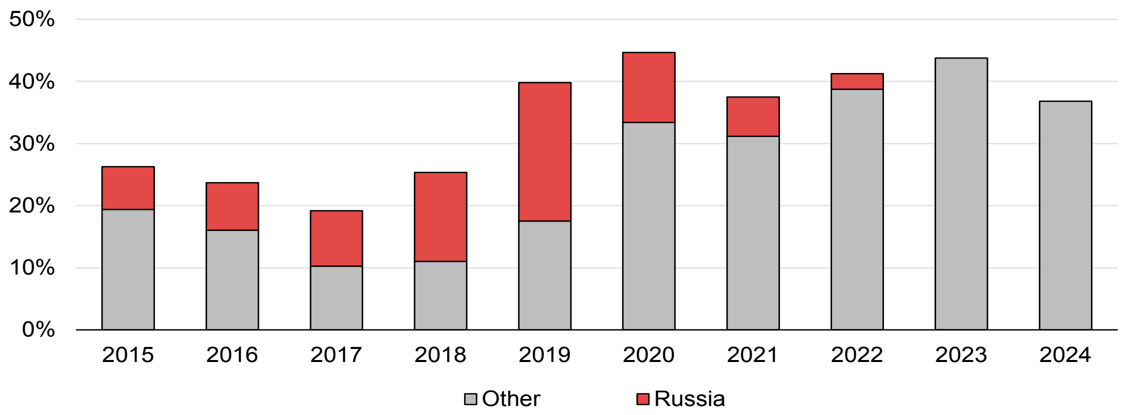
Notes: Firm capacity refers to the extent to which the estimated capacity increase can be considered reliably available across operating conditions. Capacity classified as high firmness is largely independent of weather and short-term operational assumptions, while medium and low firmness reflect increasing dependence on favourable conditions, active system management, or probabilistic availability, and may not be simultaneously available at all times or under all contingencies.

Synchronisation of Baltic electricity system with Europe marked a major milestone

The recent synchronisation of the Estonian, Latvian and Lithuanian electricity systems with Continental Europe represents not only a major technical achievement but also a political milestone. In February 2025, the Baltic states completed their de-synchronisation from the Russian and Belarussian frequency area after nearly two decades of preparation. On 9 February 2025 at 14:05 Eastern European Time, Estonia, Latvia, and Lithuania successfully synchronised their electricity grids with the Continental Europe Synchronous Area (CESA), just one day after permanently disconnecting all electricity interconnections with the Russian Federation (hereafter, "Russia") and Belarus.

Integration into the EU internal energy market allows the Baltic states to operate under common and transparent European rules, enhancing their electricity security. The three countries now have access to Continental Europe's balancing products and can participate fully in wholesale electricity markets, expanding opportunities for their renewable energy production and access to diverse generation sources across Europe. The share of imports from Russia in the Baltic states' electricity supply averaged around 10% before 2022, though commercial imports had already ceased following Russia's full-scale invasion of Ukraine.

Share of electricity imports in power supply in the Baltics by origin, 2015-2024



Extensive political and technical planning enables the complex synchronisation

Since the Soviet era, the Baltic electricity systems were integrated into the IPS/UPS [8] grid. Following independence, they remained part of the BRELL Agreement (which stands for Belarus-Russia-Estonia-Latvia-Lithuania) signed in 2001, where the Moscow operation centre maintained control over balancing the entire interconnection, including a high-voltage loop across the three states, Belarus, and Kaliningrad.

The synchronisation project started soon after the three Baltic states joined the European Union in 2004. Following Russia's 2014 annexation of Crimea, the project accelerated significantly. The timeline was further compressed in the wake of the full-scale invasion of Ukraine, when Ministers agreed to bring the deadline forward from end-2025 to February 2025.

Poland's transmission system operator (TSO) PSE played a particularly critical role in overall co-ordination and project management as the direct neighbour physically connecting the Baltic States to Continental Europe. The co-operation extended beyond infrastructure to include extensive technical preparation and joint operational procedures developed through ENTSO-E and the Continental TSOs.

Years of infrastructure reinforcement preceded the final synchronisation. Grid upgrades were implemented across all three Baltic states. Power plants were equipped with the necessary control systems, and transmission system operators (Elering in Estonia, AST in Latvia, and Litgrid in Lithuania) deployed assets to support isolated operations in case of emergencies.

Further reinforcements of interconnectors and security enhancements are planned

The 500 MW LitPol Link between Lithuania and Poland, an EU Project of Common Interest commissioned in 2015, is currently the sole alternating current (AC) interconnection providing the synchronous link to Continental Europe. The Baltic system is further connected to the Nordic system through the 700 MW NordBalt cable between Lithuania and Sweden, and the two cables EstLink 1 and EstLink 2, respectively 350 MW and 650 MW, between Estonia and Finland. Currently, the LitPol interconnection is used primarily for stability, with a transfer capacity under 200 MW, as the AC interface with Poland lacks redundancy. Reinforcement of

[8] IPS/UPS is the interconnection consisting of the Unified Power System of Russia and the Integrated Power System that currently consists of Azerbaijan, Belarus, Georgia, Kazakhstan, Kyrgyzstan, Mongolia, Tajikistan and Uzbekistan.

interconnectors are planned for 2026, with a major step of the completion with the Harmony Link in 2030, leading to trade volumes up to 1 200 MW in both directions.

Numerous physical disruptions and potential acts of sabotage reported against EU infrastructure have demonstrated the importance of protecting critical energy infrastructure. On 25 December 2024, the Baltic states experienced such a threat firsthand, when the EstLink 2 cable connecting Estonia and Finland was severed, with the cable's restoration being completed only six months later. Civilian and military co-operation on critical infrastructure protection has since increased, as demonstrated by the Baltic Sentry initiative launched in January 2025.

The Baltic synchronisation offers a powerful model for regions worldwide seeking to integrate their electricity systems. The combination of strong political will, substantial financial support, phased technical implementation, and regional co-operation provides a blueprint applicable far beyond Europe's borders. The project received over EUR 1.23 billion in grants from the EU's Connecting Europe Facility for Energy, covering around 75% of investment costs, plus additional investments through the Recovery and Resilience Facility. This strong EU support, channelled through the Baltic Energy Market Interconnection Plan (BEMIP), demonstrated the strategic importance placed on energy security in the region.

Flexibility

Evolving generation and demand patterns reshape power system needs

The Age of Electricity is underpinned by rising investments in new resources. These include growing converter-based variable solar PV and wind, battery storage systems, as well as spatially and temporally concentrated demand from EVs, heat pumps and large loads like data centres. Combined with the expansion and upgrade of transmission and distribution grids, substantial increases in the flexibility of power systems are required for secure and cost-effective integration of generation, load and storage technologies that characterise this new era.

Last year's report, Electricity 2025, focused on measures to enhance flexibility on the supply side of electricity markets by reducing the various technical, regulatory or contractual inflexibilities affecting generation. This year, we focus on demand-side applications for providing and improving flexibility. In addition, we have updated our analysis on supply side flexibility to include further examination of falling "capture rates" for solar and wind generation and the spectacular growth of battery storage systems amid declining costs in various markets.

Finally, markets with high shares of solar and wind are challenged by periods of overabundance, when supply has the potential to exceed demand for grid electricity, necessitating operators to implement measures to balance the system. Different options are addressed, from increasing control of output from small solar installations, to higher battery deployment, to refining price signals, including offering free electricity to customers.

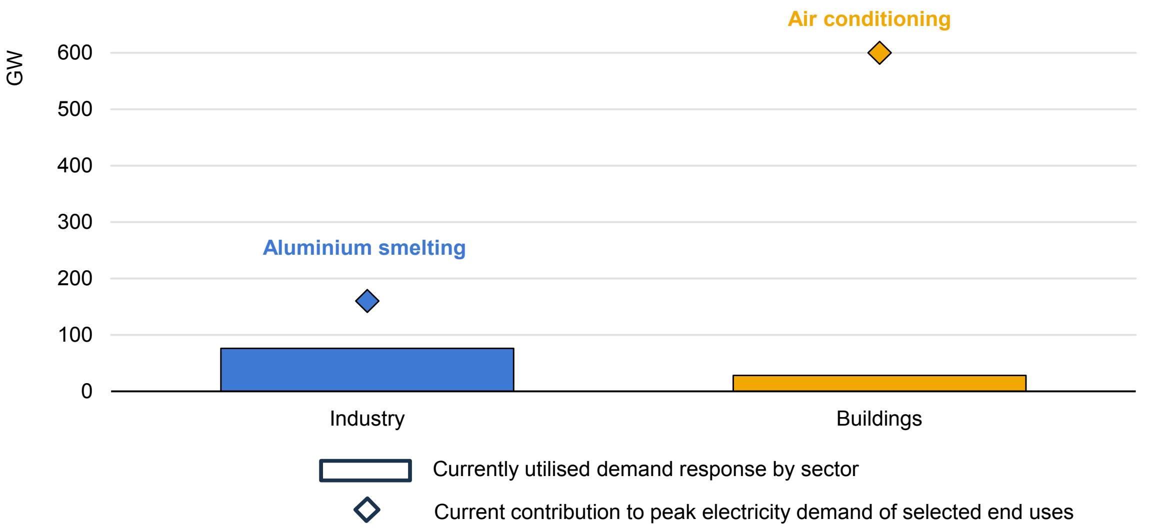
Demand response offers breakthrough benefits, yet its potential is largely untapped

With the share of variable renewable energy (VRE) sources in electricity supply rising rapidly in many regions and end-use sectors such as heating and transport becoming progressively more electrified, demand flexibility has become an essential component for power systems. In this evolving energy landscape, demand response (DR) programmes are becoming an increasingly important flexibility tool, enabling households and businesses to shift or shed their electricity use in response to grid or market signals.

In exchange, DR plans offer financial incentives, typically through contractual arrangements or participation in programmes with utilities, aggregators or system operators, or by direct participation in power markets in the case of large industrial consumers. For end-users, DR flexibility contracts provide inducements in the form of direct payments, rebates, or bill credits for curbing consumption during high-priced, peak-demand periods. When deployed at scale, DR providers can reduce peak capacity requirements, defer grid investment, lower integration costs for renewables, and strengthen resilience during system stress (see IEA's The Value of Demand Flexibility report, December 2025).

The potential for demand response is enormous. Yet, despite its substantial system-wide and consumer benefits, DR implementation globally largely remains untapped. Our analysis shows that, as of 2024, only around 100 GW of demand response is utilised on a global basis. For example, aluminium production accounts for around 160 GW of peak electricity demand in the world, but only a small share of this is currently leveraged for demand response. Similarly, residential air conditioning (AC) contributes around 600 GW, yet flexible demand response from AC loads remains marginal. Unlocking a larger share of the overall demand response potential would be possible by applying various technologies already available today, as well as by adjusting market frameworks and regulatory mechanisms accordingly across different sectors.

Demand response utilisation in industry and buildings, and peak demand contributions from aluminium smelting and air conditioning, world, 2024

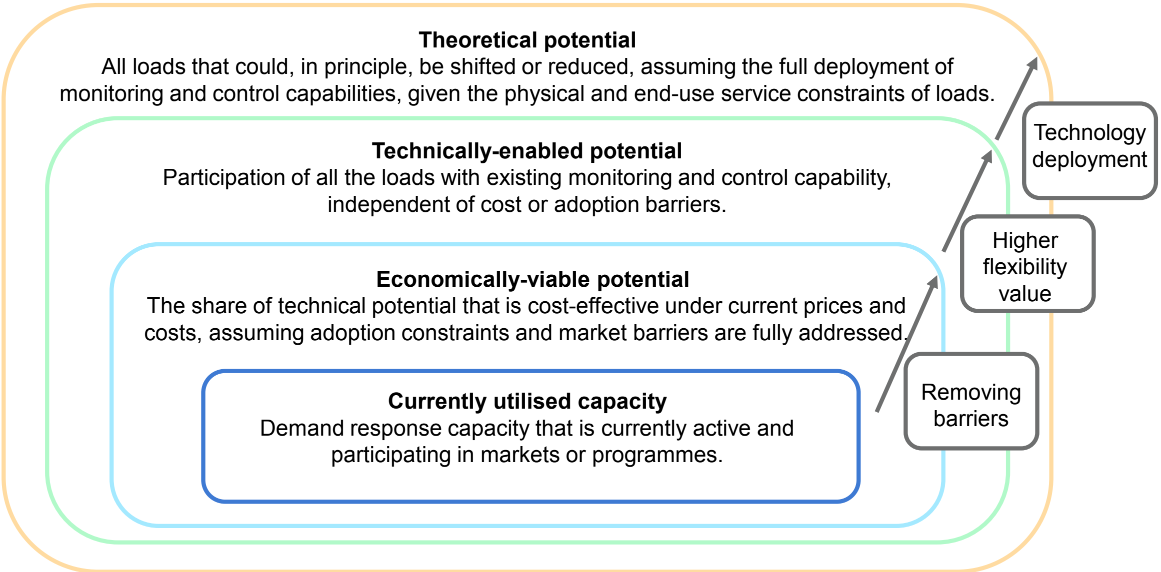


Notes: The contribution to peak electricity demand of end uses shown in the chart are global values corresponding to the sum of peak load contributions of selected end uses in the individual power systems of the world. The transport sector is not included because its current demand response utilisation is negligible compared with the industry and buildings sectors.

Demand response potential can be characterised in different ways, depending on assumptions on technology availability, deployment levels, costs, and real-world participation, including adoption barriers. *Currently utilised demand response* refers to the capacity already active in markets or programmes. However, in many cases, only part of the *economically viable potential* is realised because market barriers, regulatory frictions, and behavioural inertia prevent full participation.

Unlocking more of this economic potential becomes possible when adoption constraints and market barriers are reduced or removed. Going beyond this scope towards the *technically enabled potential* requires valuing flexibility appropriately. Technically enabled potential includes all loads that already possess the monitoring and control capabilities needed for participation, though this remains significantly below the theoretical potential. *Theoretical potential* encompasses all electricity demand that could, in principle, be shifted or reduced, assuming full deployment of enabling technologies and subject only to physical and end-use service constraints.

Hierarchy of demand response potential



Currently, the **industrial** sector provides the largest share of demand response across all sectors, with around 75 GW of utilisation. Industries across many regions currently participate in explicit DR where large consumers commit to reduce consumption during periods of system stress, typically in exchange for financial incentives such as capacity payments or activation payments when load is curtailed. Large industrial facilities with batch-based processes or on-site flexibility options often have processes that can be curtailed or shifted for short durations with relatively limited impact on output, allowing for a meaningful portion of their technical flexibility to be mobilised.

Much greater potential exists for industrial DR. Many industrial processes, especially those that rely on heat or operate in batches, can shift their electricity use more routinely via automation or thermal storage. This includes cold-storage and compressor-driven systems in manufacturing as well as melting and heat-treatment furnaces in metal processing. Overall, DR-enabling measures can raise the share of industrial load that can be adjusted with limited impact on production, yet they are not fully deployed today, leaving a high share of flexibility unused.

In the **buildings** sector, demand response utilisation is estimated at around 30 GW globally. Many building loads, such as space heating, cooling and water heating, can respond to price signals or automated controls when equipped with controllable technologies, giving the sector large long-term DR potential. However, only a small portion of this potential is currently being realised. In practice, flexibility can often be delivered through short-duration measures, such as brief compressor cycling or small thermostat set-point adjustments, with limited impact on occupant comfort, underscoring that the DR potential in buildings is far greater than current utilisation.

Limited market penetration of enabling technologies, such as smart meters, controllable appliances and home energy management systems, together with low awareness and behavioural inertia, mean that much of the demand flexibility in the buildings sector has yet to be mobilised. In addition, in many markets consumers are not directly exposed, or only partially, to short-term wholesale price signals and there are regulatory barriers that restrict aggregation of small loads to limit participation in DR. This will require more attractive financial business cases for households as well as acceptance of automated control and incentives for utilities and aggregators to invest in the necessary infrastructure and capabilities to enable participation in DR programmes.

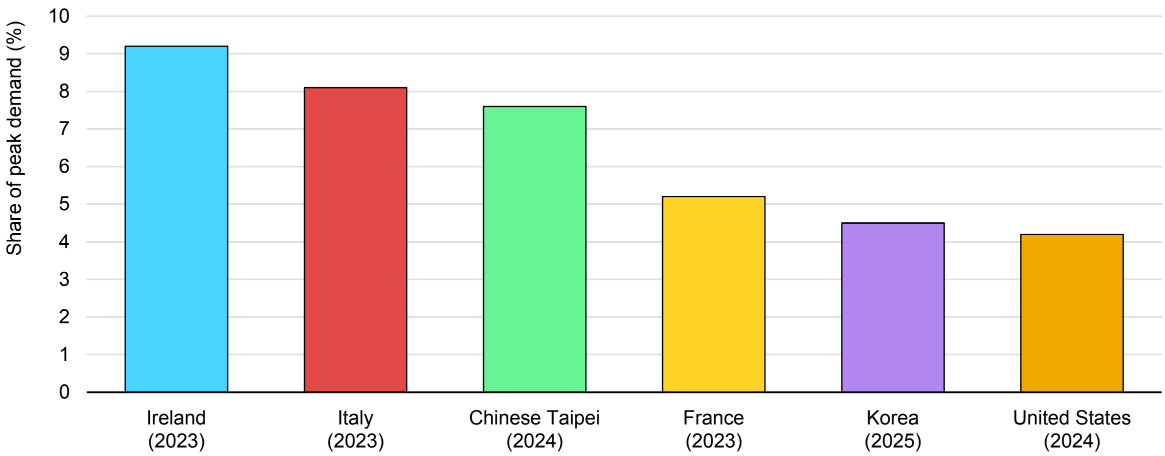
In the transport sector, utilised DR capacity remains comparatively small at less than 5 GW. However, the EV fleet in many regions is expanding rapidly, and if managed through smart charging systems that can respond automatically to price signals or external controls, the transport sector could become an important provider of demand response.

Demand response creates value across the system, yielding billions of dollars in savings

Demand response creates value across wholesale markets, networks, ancillary services and emergency operations. Two main participation pathways for demand response exist. **Incentive-based (explicit)** DR involves pre-agreed commitments, activated by operators or aggregators when needed. During extreme events, DR can provide rapid load reductions to maintain system balance and avoid blackouts. **Price-based (implicit)** DR relies on time-varying tariffs or price signals, ranging from static time-of-use pricing to dynamic tariffs indexed to wholesale electricity prices. Flexible loads can lower demand during high-price periods and increase it when prices are low or negative, supporting renewable integration and reducing curtailment. Targeted flexibility, directed at local network constraints or peak demand periods, can defer costly infrastructure upgrades, while aggregated loads (e.g. EVs) can deliver ancillary services such as frequency response. Where market rules allow, DR resources can access different market segments, enabling flexibility to be allocated to the services where it is most valuable and improving overall system efficiency. In some jurisdictions, DR can also participate in capacity mechanisms, competing with generation and storage to ensure system adequacy.

In markets such as France, Ireland, Italy, Korea and the United States explicit demand response already corresponds to a meaningful percentage of peak load, ranging from 4% to 9%. The variation across countries in the share of peak load covered by explicit demand response largely reflects differences in the scale and design of national DR programmes. In all markets shown below, industrial DR represents the largest share of explicit DR, with systems in countries such as Ireland and Italy the shares reach 8-9%, operating sizeable contracted or dispatchable industrial demand response programmes relative to their peak loads. By contrast, larger systems like the United States, Korea and France have greater DR capacity in absolute terms, but it represents a smaller fraction of their much higher system peaks.

Explicit demand response capacity as a percentage of peak load for selected electricity systems



Note: Values represent explicit demand response capacity (contracted or technically available) as a share of each system's peak load.

Sources: IEA analysis based on data from EirGrid (2024), Terna (2024), Taipower (2024), KPX (2025), RTE (2024), EIA (2025).

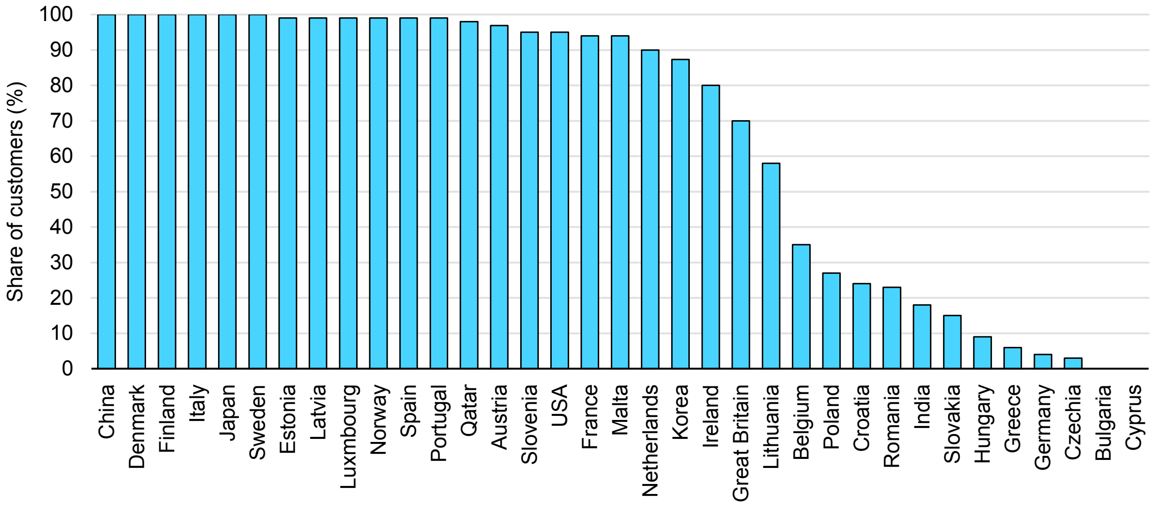
Evidence from recent studies highlights the scale of potential savings. For the United States, studies indicate that large-scale deployment of DR could reduce system costs by USD 15 billion annually by 2030. These savings are attributed to avoided generation and grid build out, as well as lower energy costs. Modelling for ERCOT suggests USD 3.3-5 billion in net savings annually, largely due to deferring costs from new investment. EU-wide analysis finds that broad deployment of flexibility by 2030 could reduce future system costs by EUR 19-37 billion each year by cutting generation costs, reducing balancing expenditures and deferring or avoiding network reinforcements, while also enabling even greater cost savings for consumers.

As regulations are updated accordingly, participation of aggregated demand resources is gaining pace

Regulatory barriers typically remain one of the main challenges to scaling demand response participation, especially with regards to aggregated demand resources. Aggregators can face contract design constraints such as market entry requirements, retail supplier consent, compensation arrangements to manage wholesale market exposures, complex measurement and verification rules, and minimum bid sizes in wholesale or balancing markets that exclude smaller distributed resources. Additionally, market settlement systems are often built around retail suppliers, making it hard to recognise demand-side contributions and to compensate consumers or aggregators directly. Many of these are legacy barriers stemming from times when the demand side was considered largely inelastic and power systems had ample overcapacity. However, with increasing electrification and flexibility needs, greater demand-side participation is becoming essential, necessitating appropriate adjustments to regulatory frameworks.

At the same time, demand response participation depends heavily on technology and infrastructure. Technically-enabled potential reflects what is feasible given available monitoring and control capability, but converting this potential into actual participation depends on system integration, operational use and market uptake. Many regions still lack widespread smart meter coverage, limiting granular data and complicating settlement. Even where smart meters exist, automation remains limited by device capabilities and integration costs. Interoperability standards and DR-ready features for appliances are still under development but gaining adoption, and industrial sites may need costly upgrades to provide verifiable demand reductions. Understanding how consumers react to price signals is also important for determining how much flexibility can come from price-based responses versus event-based programmes.

Share of electricity customers with smart meters



Notes: Figures represent the most recent available smart meter penetration data from the listed sources. The chart shows the share of customers with smart or advanced meters. In every case, these are communicating interval meters that allow remote readings and support time-varying tariffs. However, the level of functionality may differ across countries.
Sources: IEA analysis based on data from ACER and CEER (2024), ESB Networks (2025), EIA (2025), ERSE (2025), E-Control (2025), Berg Insight (2024), The Peninsula Qatar (2025), NSGM (2025), DESNZ (2025), Bundesnetzagentur (2025) and Elec Times (2024).

New technologies such as smart-charged EVs, heat pumps with advanced controls, and behind-the-meter storage are expanding potential flexibility. Much of this emerging demand is flexible, with controllability largely determined by the underlying end-use service, though the degree of flexibility varies across technologies and depends on factors like building characteristics and control capabilities. However, barriers persist, including fragmented interoperability and interface requirements, uneven implementation of secure communications, and concerns over privacy and cybersecurity. Customer consent and trust also continue to be essential, alongside access to reliable information and simple, low-disruption participation pathways. Without these foundations, many smaller consumers remain locked out of flexibility opportunities, and the system underuses its available resources.

Several jurisdictions have introduced reforms to overcome these barriers and unlock DR. In the **United States**, aggregated demand resources are being enabled across wholesale energy, capacity and ancillary services, under FERC Order 2222, as part of distributed energy resource aggregation, with all RTOs and ISOs having submitted initial compliance filings. Emergency events have also demonstrated reliability value, with ERCOT deploying Load Resources (LR) during a September 2023 Energy Emergency Alert. LR programmes enable system operators to instruct large industrial, commercial, or institutional electricity consumers to temporarily reduce their power consumption (curtail load), including during periods of system stress, to help maintain grid stability. These consumers are paid to be available to rapidly reduce demand when called, allowing the operator to use demand reduction as a fast-acting alternative to firing up traditional power plants when reserves are low. ERCOT has had recent progress in the Aggregate Distributed Energy Resource (ADER) pilot project, which has begun to clarify pathways for aggregated, behind-the-meter resources. This includes controllable demand adjusted by the party co-ordinating the aggregation per instructions to participate in wholesale markets beyond emergency conditions.

In **Canada**, Québec demonstrates how residential DR programmes can scale significantly over time. Hydro-Québec has progressively expanded residential schemes that combine implicit and explicit DR mechanisms. The Winter Credit Option allows customers to stay on the standard residential tariff while earning bill credits for reducing consumption during winter peak events. Rate Flex D is a dynamic pricing tariff offering lower prices for most of the winter and higher prices during a limited number of critical peak periods. Hydro-Québec introduced these offerings in the winter of 2019/20, enrolling around 20 000 customers. In the 2024/25 season, participation had expanded to about 340 000 customers, including roughly 260 000 in the Winter Credit Option and 80 000 under Flex rates. The associated power shed per peak event rose from about 16 MW to around 330 MW over the same period, while the number of households represented per event rose from about 2 300 to 44 000.

In **Europe**, a legal framework supporting demand flexibility was implemented in 2019, with EU rules requiring member states to allow DR through aggregation to participate alongside generators in all electricity markets on a non-discriminatory basis. In liberalised retail markets with customer choice, time-varying retail tariffs often provide a low-friction pathway for implicit DR. In March 2025, ACER submitted a draft EU-wide network code on demand response to the European Commission to harmonise roles, data access, baselining and aggregator entry. It then released a report with 12 "no-regret" actions to unlock flexibility, including stronger price signals, proportionate baselines, simpler market entry for aggregators and faster smart-meter rollout. In France, reforms to peak and off-peak time windows for retail electricity contracts under the "heures pleines/heures creuses" option are progressively adding more daytime off-peak windows, particularly in summer, to better reflect system needs and periods of high renewable output. ACER-CEER's 2024 Market Monitoring Report underlines the implementation gap by showing that access to time-varying retail tariffs and enabling technologies remains uneven across member states. At the national level, many countries provide routes for DR, although the design varies. France's NEBEF is notable as it allows aggregators to monetise load reductions directly in energy markets without requiring supplier consent, while Ireland's Demand Side Units participate in the Single Electricity Market and receive capacity payments for their contributions to system adequacy.

In the **United Kingdom**, one of the largest household demand response programmes has emerged through the Demand Flexibility Service (DFS). First launched in winter 2022/23, DFS enabled households and businesses to participate through their suppliers or aggregators, with more than 1.6 million customers participating in the first year. Over winter 2023/24, participation grew to 2.6 million households and businesses, with DFS delivering 3.7 GWh of downward demand response across all events during the winter. In winter 2024/25, DFS shifted to a merit-based, year-round margin tool, procuring DR based on priced offers, with lower-cost flexibility dispatched first to support system margins. Across 44 events, around 5.4 GWh of DR was procured, with approximately 3.9 GWh delivered.

In **Japan**, demand response aggregators are formally recognised as "specified wholesale suppliers" under the amended Electricity Business Act. Ministry of Economy, Trade and Industry (METI) materials describe the aggregator authorisation regime and the Organization for Cross-regional Coordination of Transmission Operators' (OCCTO) FY 2024 statistics lists 60 specified wholesale suppliers. Japan's capacity market includes "activation-command resources", a category that can include demand response, customer-sited generation, and aggregated small-scale units. In the main capacity market auction conducted in FY 2024 for the FY 2028 delivery year, 6.4 GW of activation-command resources were contracted, representing around 4% of total cleared capacity. OCCTO conducted a one-year-ahead additional capacity auction in 2024 for the FY 2025 delivery year, in which 270 MW of activation-command resources were offered and contracted. Following the additional auction, activation-command resources amounted to around 3.2 GW of total capacity secured in the capacity market for FY 2025.

Australia has brought flexible demand into wholesale dispatch via the Wholesale Demand Response Mechanism. AEMO's annual 2025 Wholesale Demand Report shows around 74 MW of registered capacity across 158 sites, representing less than 1% of peak demand. Wholesale demand response was dispatched on 23 days (240 MWh) between July 2024 and May 2025, reflecting small-scale but operational integration into wholesale dispatch. In January 2026, the government also announced the Solar Sharer Offer, which is scheduled to begin on 1 July 2026 in New South Wales, South Australia and South East Queensland. This scheme would require retailers to offer at least three midday hours of free electricity in their default (standing) offer, to encourage consumption during periods of high solar output, aiming to shift demand away from more expensive evening peaks.

In **India**, the Ministry of Power mandated time-of-day tariffs for all consumers, except agriculture, by April 2025. As of January 2026, around 53 million smart meters have been installed. At the state level, Maharashtra mandated demand response through 'Demand Flexibility Portfolio Obligations', which requires distribution companies to procure demand flexibility resources equal to 1.5% of the previous financial year's peak demand in FY 2025/26, rising to 3.5% by FY 2029/30. In practice, this requires distribution companies to assemble a portfolio of consumers or controllable loads capable of adjusting demand during peak periods, with compliance verified through at least one annual demand flexibility event under the state's measurement and verification framework.

In **China**, demand response expanded through provincial programmes, where industrial and commercial consumers are enrolled to shift or curtail load during peak periods. The National Development and Reform Commission's 2023 revised demand-side management measures highlighted demand response as a core element of flexibility provisions alongside storage and interconnection, setting targets through 2025. In 2024, the National Development and Reform Commission, the National Energy Administration and the National Data Administration jointly issued the Action Plan for Accelerating the Construction of a New Power System (2024-2027). This plan outlines how demand response capacity should achieve at least 5% of peak load while also making efforts to reach 10% of peak load in certain areas. In parallel, China is promoting market-oriented DR through aggregators, enabling distributed loads and storage to participate in electricity markets, marking a shift away from purely administrative DR.

In the **United Arab Emirates,** Dubai's DEWA introduced a residential DR pilot with smart thermostats, allowing the utility to adjust AC set-points during peak periods in return for customer incentives. Abu Dhabi's Department of Energy is implementing DR programmes with major industrial and commercial consumers, with their 2024 pilot programme reducing peak demand by an average of 106 MW across multiple events, with a maximum reduction of 210 MW.

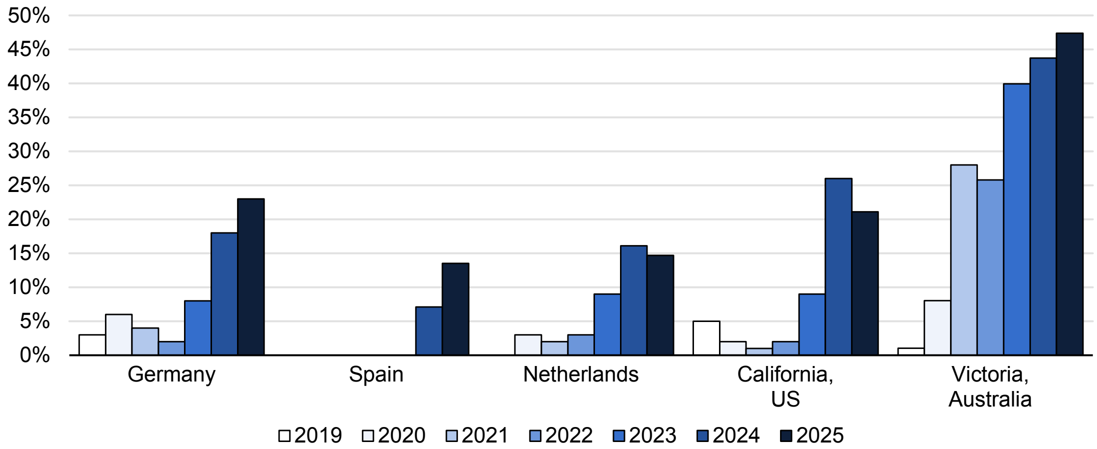
Solar PV capture rates decline, but storage can help boost system value

The rapid expansion of VRE capacity across markets between 2018 and 2025, particularly solar PV (+337 GW in Europe, +201 GW in the United States, +34 GW in Australia), together with other inflexible generation and lagging demand flexibility have reshaped hourly price patterns. This is especially notable in declining capture rates[1] for solar PV, impacting the business cases of projects.

[1] Electricity market capture rates measure the relative market value of different generation technologies or fuel types, by comparing generation-weighted average price earned by one unit of energy from each source to the unweighted average wholesale market price over the same period. A capture rate below 100% indicates that a source tends to generate during low-price hours, while values above 100% reflect operation predominantly in higher-price periods. Phrased differently, capture rate is the total spot revenue for a generator(s) divided by its total volume (MWh) to get USD/MWh, divided by unweighted average price (USD/MWh). If a generator produced a constant power output for the whole time period, the capture rate would be 100%.

For example, in Germany very low or negative prices increasingly coincide with solar PV output, where 25% of its generation volume is now during negative price periods. In Australia, this share has surpassed 40% in Queensland and Victoria. Greater flexibility on the supply and demand sides, especially supported with storage, can help to boost the market value of solar PV generation by shifting generation to higher-priced hours.

Share of utility-scale solar PV yearly generation volume at negative prices in selected countries and regions, 2019-2025

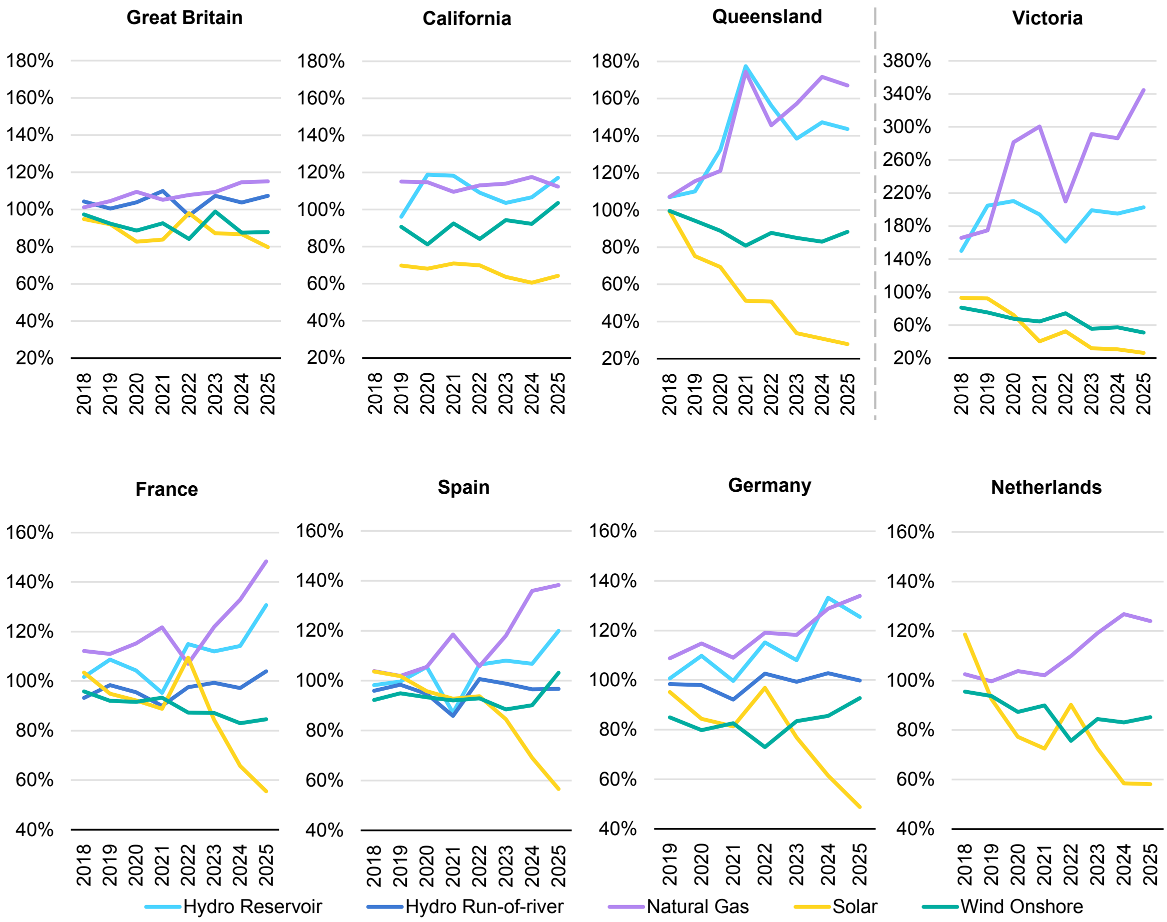


Note: In Spain, negative electricity prices on the day-ahead market were permitted in December 2023 following the implementation of updated rules on the operation of electricity markets.
Source: IEA analysis based on data from IEA Real-Time Electricity Tracker (2025).

Capture rates of utility-scale solar have shown a sharp downward trend in recent years, falling from more than 100% in 2018 to below 60% in 2025 in many European markets such as France, Spain, Germany and the Netherlands. European levels of capture rates for utility-scale solar PV are now in line with regions that have historically low capture rates such as CAISO (California), where more than 20% of utility-scale solar PV generation takes place during negatively priced hours.

In Australia, these rates have decreased even more significantly in various National Electricity Market (NEM) regions, from around 100% in 2018 to less than 30% in Victoria and Queensland, and to below 50% in South Australia in 2025. Wind generation capture rates also face downward pressure in some areas, although these have shown more resilience in recent years by remaining generally above 80%. By contrast, in the considered markets in this analysis, flexible dispatchable technologies such as hydropower and natural gas have capture rates 2 to 3 times the value obtained by utility-scale solar PV, up from less than 1.1 in 2018. Natural gas capture rates have reached record-highs in Victoria, above 340% in 2025, and are rising in Europe, not only in countries where gas accounts for a marginal share in the mix like France (3%) but also in Spain, Germany, the United Kingdom, Denmark, Ireland or the Netherlands.

Capture rate of generators by fuel type in selected countries and regions, 2018-2025

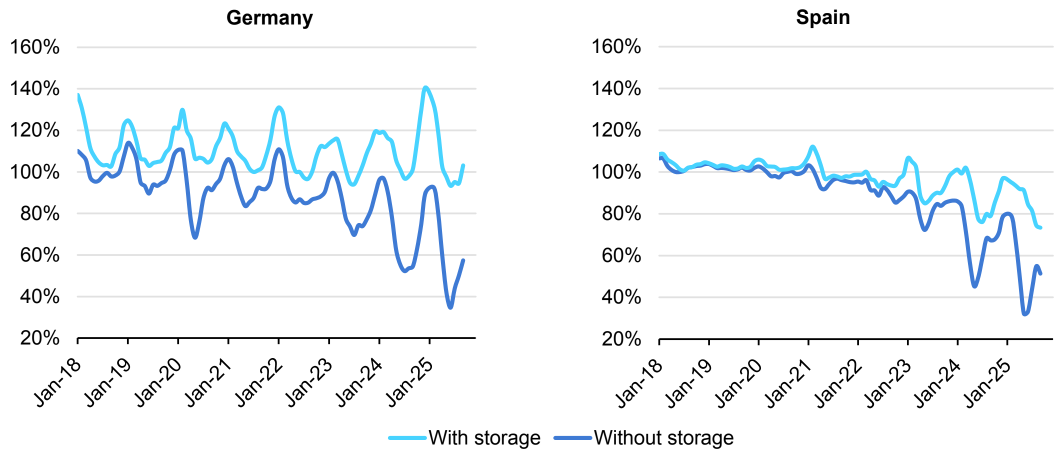


Notes: Electricity market capture rates measure the relative market value of different generation technologies or fuel types, by comparing generation-weighted average price earned by one unit of energy from each source to the unweighted average wholesale market price over the same period. A capture rate below 100% indicates that a source tends to generate during low-price hours, while values above 100% reflect operation predominantly in higher-price periods. Phrased differently, capture rate is the total spot revenue for a generator(s) divided by its total volume (MWh) to get USD/MWh, divided by unweighted average price (USD/MWh). If a generator produced a constant power output for the whole time period, the capture rate would be 100%.

Source: IEA analysis based on data from [IEA Real-Time Electricity Tracker (2025)].

These trends indicate the rising value of flexible supply with the ability to shift generation to higher-priced periods. Utility-scale batteries can especially result in higher market values of VRE. While doing so, they can also contribute to increasing the system value by improving dispatchability, reducing curtailment, and lowering total system costs. While most battery energy storage systems (BESS) currently taking part in electricity markets are standalone, pairing VRE projects with energy storage is becoming more common.

Monthly capture rate of utility-scale solar PV with and without paired battery storage in Germany and Spain, 2018-2025



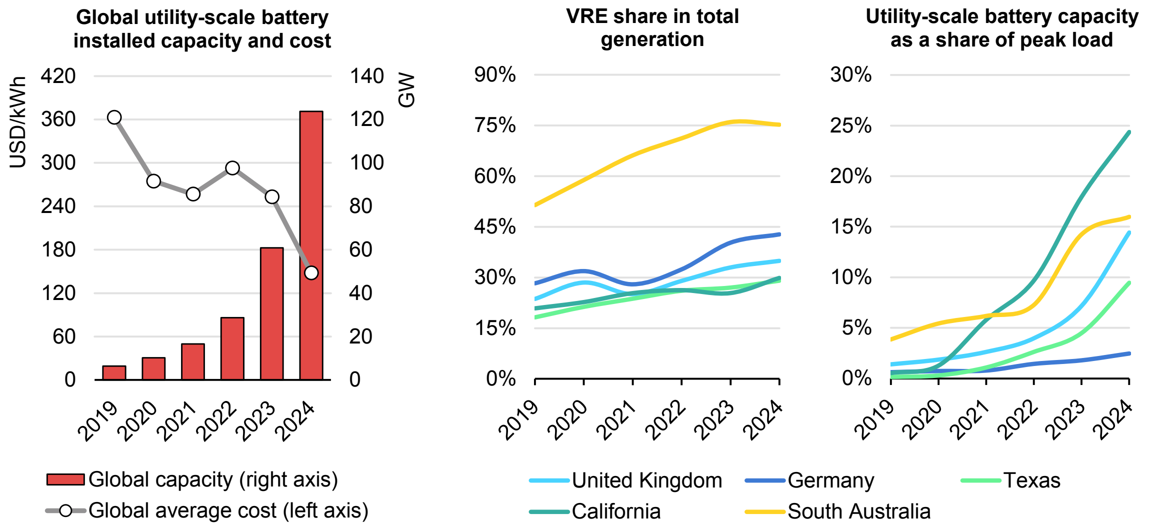
Notes: Series are presented as a 3-month moving average. Storage is defined as a BESS with no grid charging, 50% storage power ratio and 2-hour storage duration.
Source: IEA analysis based on data from Pexapark (2025).

Utility-scale batteries are expanding rapidly, strengthening system flexibility

Battery storage has become one of the most versatile tools for providing short-term power system flexibility. They can support the integration of wind and solar power by responding quickly to provide system balancing and grid support services, contribute to security of supply through capacity provision, and shift renewable generation to periods of high demand. As a result, they help defer or reduce the need for some network upgrades. Battery storage can also help greatly with the secure and cost-effective integration of new types of loads such as EVs, heat pumps and data centres, where the consumption can be highly correlated across location and time.

Costs have declined significantly in recent years, with battery storage project costs falling by about 40% in 2024 to around USD 150/kWh, underpinning a strong increase in deployment. In 2024, utility-scale battery storage additions reached 63 GW, marking another record year and bringing total installed capacity to 124 GW. The contribution of utility-scale batteries in meeting peak demand is increasing in many power systems. In California, the ratio of installed utility-scale battery storage to peak load stood at almost 25% in 2024, and around 15% in South Australia and the United Kingdom, which were all less than 5% in 2019.

Utility-scale battery project costs, VRE share and utility-scale battery storage capacity relative to peak load, by region, 2019-2024



Notes: These figures use batteries' nameplate capacities. The actual battery discharge during a peak load event may be significantly below aggregate nameplate capacity. This can be because of temperature derating, noting that peak demand events are correlated with extreme temperatures. Additionally, batteries may not be fully charged when peak demand events start, and may have a duration which is less than the duration of the demand spike. Some capacity may be assigned to provide ancillary services, in a way which precludes them from providing energy during a peak demand event. These figures refer to grid-scale batteries, and exclude industrial and domestic batteries. In some countries, such as Germany, home storage capacity is far larger than grid-scale storage.

Sources: IEA analysis based on data from AEMO (2025), AER (2025), CAISO (2025), EIA (2025), DESNZ (2025), ERCOT (2025), Open Electricity (2025) and MaStR (2025).

Large project pipelines for utility-scale batteries reflect strong investor interest, but many projects face multi-year delays in securing grid connection and permitting, including planning approval processes and addressing local opposition related to issues such as fire safety. Projects also encounter uncertain and volatile revenue streams, or struggle to access financing on suitable terms.

Average battery size is increasing overall, though average duration varies by market

Global battery storage additions in the power sector surged in 2024, with around 63 GW of new utility-scale capacity installed. A key driver of this expansion has been the rapid decline in lithium-ion battery pack costs. In 2024, average pack prices fell by around 20%, followed by a further decrease of about 8% in 2025.

Average capacity of utility-scale battery storage has been increasing in many markets, in line with the evolving market needs for flexibility and capacity as VRE penetration increases. In the United States, average capacity more than doubled from about 15 MW in 2021 to around 35 MW in 2024. This trend is also seen in Europe, where a 1 000 MW (4 000 MWh) battery storage system is being built by LEAG and Fluence in Germany, set to become the largest battery storage project on the continent. In Australia, the Eraring battery storage system is set to expand from a capacity of 460 MW to 700 MW (and a volume of 2 800 MWh) in 2027, which will make it the country's largest utility-scale project. Saudi Arabia commissioned a 500 MW (2 000 MWh) battery storage facility in Bisha in 2025, adding to the growing number of large-scale projects worldwide.

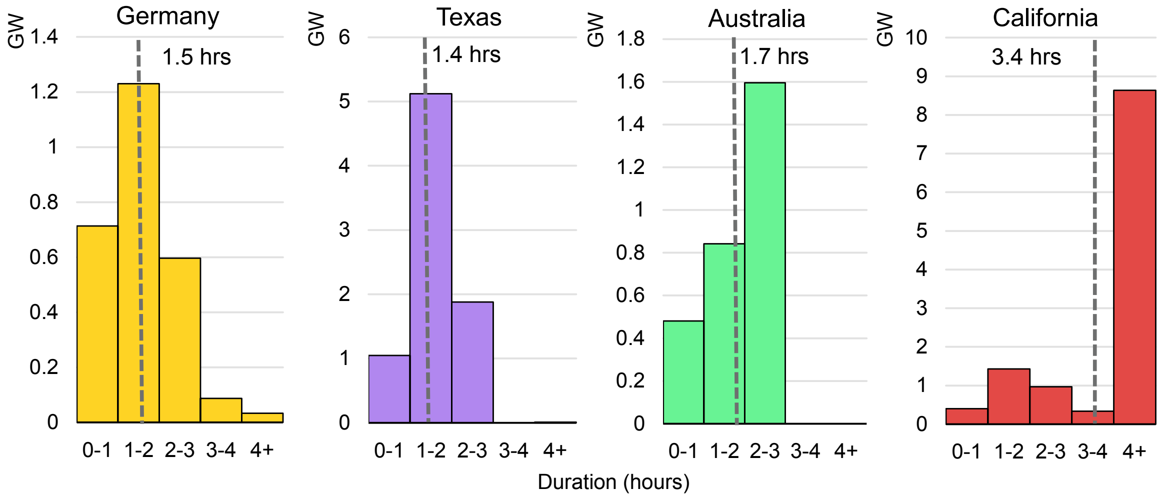
China has become the largest market globally for battery storage, both in terms of annual additions and cumulative installed capacity. China added about 42 GW (101 GWh) of new-type energy storage capacity [2] in 2024, corresponding to an average duration of around 2.3 hours. By end-2024, Inner Mongolia was the leading province in China, with around 10.2 GW of new-type energy storage. About 66 GW (189 GWh) was also added in 2025, bringing the cumulative capacity to approximately 145 GW by the end of the year. By the end of 2025, standalone energy storage accounted for 58% of cumulative installations.

The rapid declines in costs are particularly apparent in batteries with higher storage durations. In Great Britain, 98% of new capacity added in Q4 2024 had a duration of 2 hours or more. In Australia's National Electricity Market, 95% of capacity post-2024 is designed for 2 hours or more, and is expected to increase average duration from 1.5 hours in 2024 to 2.5 hours in 2027. In China, the average duration of cumulative new-type energy storage installations increased from about 2.1 hours in 2021 to around 2.6 hours in 2025. California stands out for its concentration of battery storage with a 4-hour duration, in part due to Resource Adequacy rules that assign capacity value based on sustained output over this period. This reflects a trend in some markets, where new battery projects are being built with longer durations to provide greater energy shifting potential.

Beyond these market-driven trends, several countries are introducing state-backed procurement schemes to support longer-duration battery storage. In Italy, the first MACSE auction has already contracted 10 GWh of utility-scale battery storage for delivery in 2028, including about 1.3 GWh from battery storage with durations of 8 hours or more. Italy's auction mechanism aims to procure 50 GWh of BESS capacity by 2030 to support renewable energy integration. Great Britain has introduced a long-duration energy storage cap and floor scheme requiring projects to discharge at full power for at least eight hours, with an indicative capacity range of 2.7 to 7.7 GWh by 2035.

[2] New-type energy storage excludes pumped hydropower and includes both front-of-the-meter and user-side installations.

Distribution of capacity and duration of existing battery storage projects in selected markets



Notes: The dashed lines indicate the capacity-weighted average duration. Australia refers to the National Electricity Market of Australia. Each band on the x-axis represents the range of values covered by that interval. For example, 0-1 includes all values greater than or equal to 0 and less than 1, 1-2 includes values from 1 up to but not including 2, and so on. The final band (4+) includes all values greater than or equal to 4. Data for the United States is up to the end of 2024, data for Australia is up to the end of Q2 2025, and data for Germany is up to January 2026.

Sources: IEA analysis based on data from AEMO (2025), EIA (2025) and MaStR (2025).

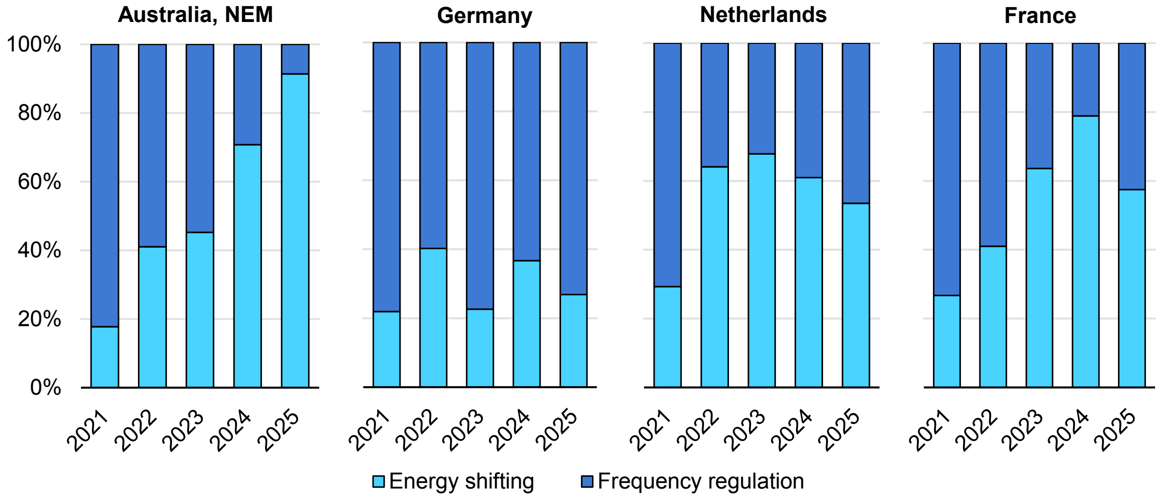
Battery storage revenues can shift as deployment scales

Battery projects increasingly draw on multiple revenue streams to build a viable business case. In most markets, the main sources of revenue are ancillary services (e.g. frequency control), energy arbitrage, and, where in place, capacity mechanisms that remunerate availability to ensure that sufficient firm capacity is available during periods of peak demand. Other revenue sources are from locally procured congestion or constraint management services in some regions. Under these arrangements, system or network operators procure flexibility from available providers to adjust net injections or withdrawals at specific locations or times to help alleviate network constraints. As battery use has expanded, the composition of these revenues has evolved. Utility-scale batteries dominate various ancillary services across many regions. They are, for example, now the primary providers of flexible regulation services in California and Texas, account for the largest share of frequency control ancillary services in Australia, and they currently supply most of the dynamic containment frequency response in Great Britain.

As battery penetration expands, ancillary service markets can become increasingly competitive, reducing revenues and narrowing profit margins for new battery projects. Prices for fast-frequency services, which rose sharply when new products were first introduced and supply was limited, have declined as battery capacity has increased. For example, for ERCOT the total cost of ancillary services per MWh fell by 74% in 2024. In Australia's NEM, total Frequency Control

Ancillary Services (FCAS) costs were [AUD 13 million (Australian dollars) in Q1 2025](), a 55% decline compared with the same quarter the previous year, driven by lower FCAS prices.

Breakdown of revenue stack for utility-scale batteries in selected markets

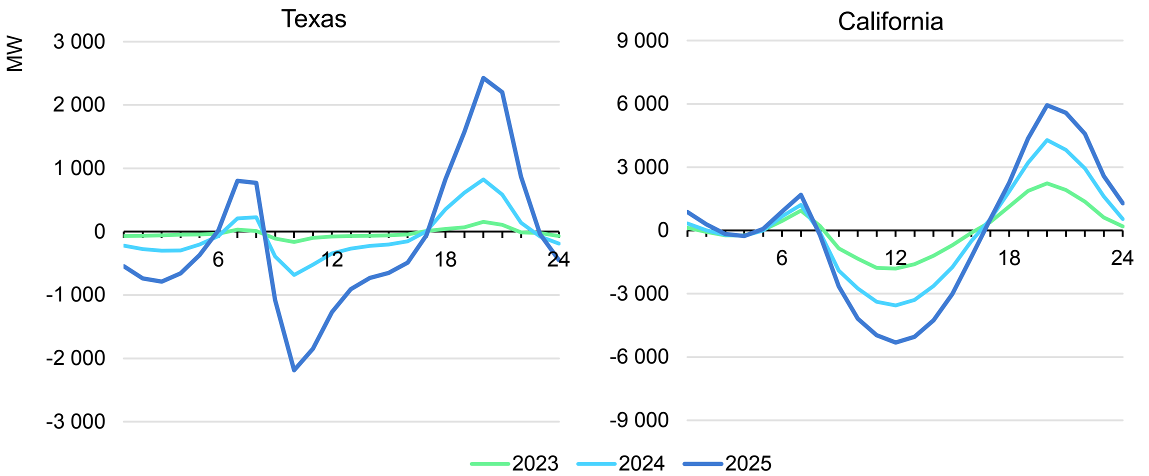


Notes: Australia refers to the National Electricity Market of Australia. Values for Australia are based on total quarterly battery revenue from wholesale electricity and ancillary service markets only. The 100% scale refers to the composition of revenue categories. The revenue stack in the European countries shown considers a hypothetical 1 MW/2 MWh BESS and includes only revenues from energy shifting and frequency regulation; capacity-related revenues are excluded and may not be available in all markets.
Sources: IEA analysis based on data from AEMO (2025) and Pexapark (2025).

While early battery projects in many markets primarily targeted ancillary services, recent capacity additions are increasingly used for energy shifting and capacity provision. Battery storage is well suited to short-term intraday energy shifting, typically in the 1-4 hour range, enabling solar generation to be moved into evening peak periods. In California, battery storage has significantly contributed to meeting evening peak demand, at times supplying about a quarter of peak load and displacing higher-cost, higher-emissions gas-fired generation. This shift is also reflected in the rising share of systems with 2-hour or longer durations, which can achieve higher revenues by capturing intraday price spread.

Beyond intraday and day-ahead energy shifting, battery storage is more frequently deployed to manage short-term imbalances resulting from forecasting errors and rapid changes in net load. In systems with rising shares of VRE, deviations between day-ahead schedules and real-time conditions can become significant, particularly during ramping periods, thereby raising the value of fast-responding storage assets. In the United States, for example, California's battery storage is increasingly dispatched in real-time energy markets to correct short-term deviations from day-ahead schedules. In Great Britain, battery storage plays an expanding role in the Balancing Mechanism, supporting system balancing during real-time operation. In Germany, continuous intraday trading has become an important channel for battery storage to monetise its flexibility, enabling adjustment of positions close to delivery as renewable output evolves.

Annual average hourly battery output across selected markets

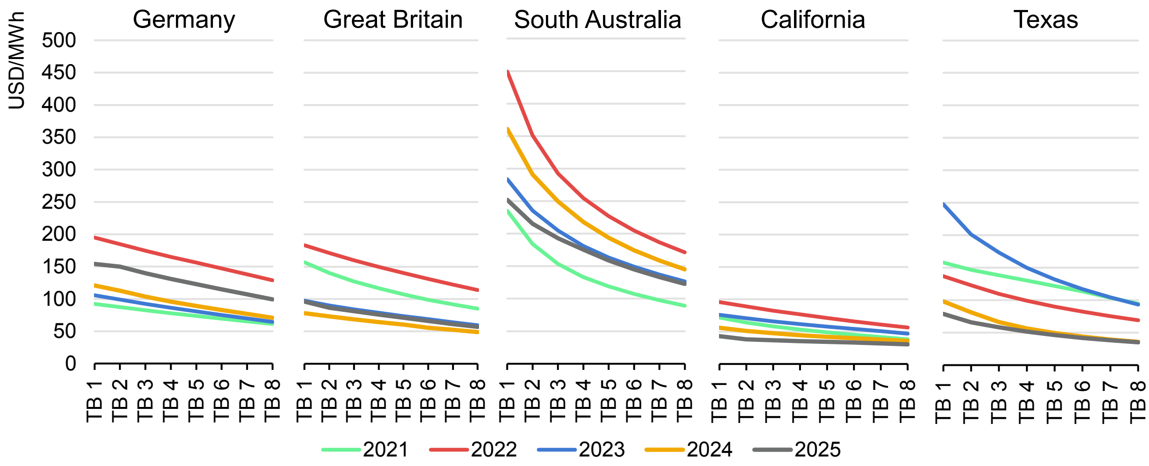


Notes: Negative power output means the battery is charging, while positive output means it is discharging, based on net energy-market battery output to the grid. The analysis includes batteries dispatched explicitly as storage in CAISO and excludes hybrid resources whose operation is dispatched jointly with generation.
Sources: IEA analysis based on data from ERCOT (2025) and CAISO (2025).

The revenue potential from energy shifting is directly related to price spreads in spot wholesale electricity markets. The normalised annual average of the daily cumulative price differences between the highest and lowest prices provides a useful indicator of this potential. A downward slope in the normalised annual average daily spread curve indicates that expanding the number of hours in the energy shifting window reduced the average spread captured per hour, with a steeper slope signalling a larger drop-off in incremental value as additional hours are included.

The size of these multi-hour spreads varies by region and year, with South Australia consistently recording the largest spreads. California, Texas and Great Britain show more moderate spreads, with levels in 2024 generally lower than in 2023. Year-on-year movements are mixed, influenced by factors such as fuel prices and weather conditions, but the widening of spreads with larger numbers of hours highlights the opportunity for battery storage capable of multi-hour shifting. While the rising share of batteries in energy shifting can put downward pressure on the price spreads, the simultaneously growing share of VRE provides an upward pressure. Therefore, the evolution of price spreads will strongly depend on market-specific dynamics.

Normalised annual average daily cumulative price difference between highest and lowest hourly prices by region, 2021-2025



IEA. CC BY 4.0.

Note: The plotted metric is also referred to as TBn, where n denotes the number of hours considered. TBn represents the annual average of the daily difference between the sum of the n highest-priced hours and the sum of the n lowest-priced hours. This is then normalised by dividing the cumulative spread by n. For example, for TB2, the cumulative spread is divided by 2, for TB3, it is divided by 3, etc.

Different instruments can help de-risk utility-scale battery project development

As with many other capex-intensive assets, batteries benefit greatly from contracts or mechanisms that provide long-term revenue stability that allow for de-risking to access better financing conditions, complementing the wholesale electricity price signals on the spot market. In well-functioning and sufficiently liquid markets, price signals with adequate spatial and temporal granularity play an essential role in indicating the value of additional flexibility in the system and can incentivise the deployment of flexibility sources such as batteries. Therefore, allowing for such price signals is crucial for a cost-effective market-based deployment of flexibility resources. However, despite the growing potential for energy shifting in many markets, long-term revenue uncertainty can still be a challenge. This is especially relevant as opportunities for energy shifting can be quite variable, depending on renewable output, transmission constraints and fuel price trends, resulting in a revenue base that is technically diverse and financially volatile, which can complicate debt financing and raise the cost of capital.

Financial hedging instruments commonly used in power markets, such as forward contracts, can help with hedging price risks, but their limited horizon (often one year) can be insufficient to secure long-term price stability in markets where amortisation periods are longer, which can make mechanisms and contract types with longer durations more desirable. In addition, such conventional financial instruments may not be well-suited to batteries' multi-service revenue profiles. These instruments typically hedge price levels rather than a battery's charge-discharge margins associated with energy arbitrage. Also, they are designed for assets typically with a single, dominant revenue stream, whereas batteries can have diverse and relatively volatile revenue streams (e.g. energy arbitrage, ancillary services and capacity payments).

From a project finance perspective, long-term contracts of around 15 years are generally viewed as favourable for reducing merchant risk and supporting bankability, however such long tenors are rare. In California, the Resource Adequacy scheme mandates that load-serving entities sign private contracts to pay for capacity up to 3 years in advance. In 2025, these capacity obligations were disaggregated into each hour of the day, under the Slice of Day framework. Capacity payment schemes such as these attempt to shift downside risk away from investors by providing a revenue floor for each megawatt of capacity. By contrast, contracts-for-difference (CfD) and schemes such as the Long-Term Energy Service Agreements (LTESAs) in New South Wales, are intended to provide a revenue floor for each megawatt-hour of energy. LTESAs have a maximum duration of 20 years, although in 2025 some successful bidders opted for shorter terms to increase the competitiveness of their bids. Capacity payments and price hedging schemes can make projects more bankable for investors, but do so by shifting some of the downside risk to consumers or the public sector.

The diversity of support schemes in use reflects different approaches to allocating risk between investors and consumers. One approach has been to provide capital-based investment support to reduce upfront financing requirements. For example, in Poland, the European Commission approved a EUR 1.2 billion scheme to support investments in electricity storage, financed partly by the Recovery and Resilience Facility, and partly by the Modernisation Fund. This scheme provides upfront support, including grants and loans, to lower capital costs while leaving projects exposed to ongoing market revenues.

One example of a mechanism designed to mitigate revenue risk is Greece's support scheme for battery storage, illustrating how these principles are applied in practice. It combines an upfront investment grant with a ten-year, two-way CfD style operating support applied to annual market revenues. Under this arrangement, projects bid an annual 'Base Revenue' in EUR/MW-year, representing the level required for financial viability, while the realised 'Market Revenues' from participating in day-ahead, intraday and balancing markets are determined from market settlement data under a methodology set by the regulator. If Market Revenues fall below the Base Revenue, the CfD provides a top-up; if they exceed it, the surplus is returned through a claw-back. This structure effectively establishes a revenue floor with two-way adjustment across the covered market revenue stack, supporting long-term cash flows.

In addition to policy support mechanisms, ownership structures also influence how revenue risk is managed. Across regions, utility-scale battery storage assets are owned by a mix of specialist developers, listed funds, independent power producers and integrated utilities. In Great Britain, listed funds such as Gresham House and Gore Street, together with developers and owners such as BW ESS, are among the largest owners of operational battery storage capacity. In Australia, ownership includes global investors and developers such as Akaysha Energy as well as integrated utilities like Origin and AGL. In California and the wider United States, independent power producers and utilities, including LS Power, Vistra and NextEra Energy Resources, own many of the largest grid-scale storage projects. These differing investor profiles shape the degree of merchant exposure they are willing to accept and their interest in long-term contracting arrangements.

Alternative contractual agreements are often relied upon to help improve revenue certainty and bankability. For example, a tolling agreement provides the asset owner with a fixed payment while a third-party optimiser operates the battery and assumes market risk. Another option is the revenue floor contract, which guarantees a minimum income when using a third-party optimisation service. The guaranteed revenue under a floor contract is typically lower than in a tolling agreement, as the owner retains some exposure to market conditions and therefore the potential for upside returns. By contrast, merchant strategies carry more downside risk, which raises the required rate of return. Recent examples in the United Kingdom such as Gresham House's long-term revenue floor with EDF and the 7-year tolling contract between BW ESS, Penso Power and Shell show how these structures are being adopted to provide more revenue certainty.

Several countries are introducing regulated remuneration mechanisms to reduce investment risk for battery storage. For example, in Italy the MACSE scheme offers long-term contracts of up to 15 years through competitive auctions, under which successful projects receive a regulated premium (EUR/MWh-year) linked to contracted storage capacity, with revenues from market participation settled under predefined rules. In the most recent MACSE auction held in September 2025, around 10 GWh of battery storage was awarded, with projects expected to become operational by 2028. This approach strengthens bankability while helping to contain overall system costs.

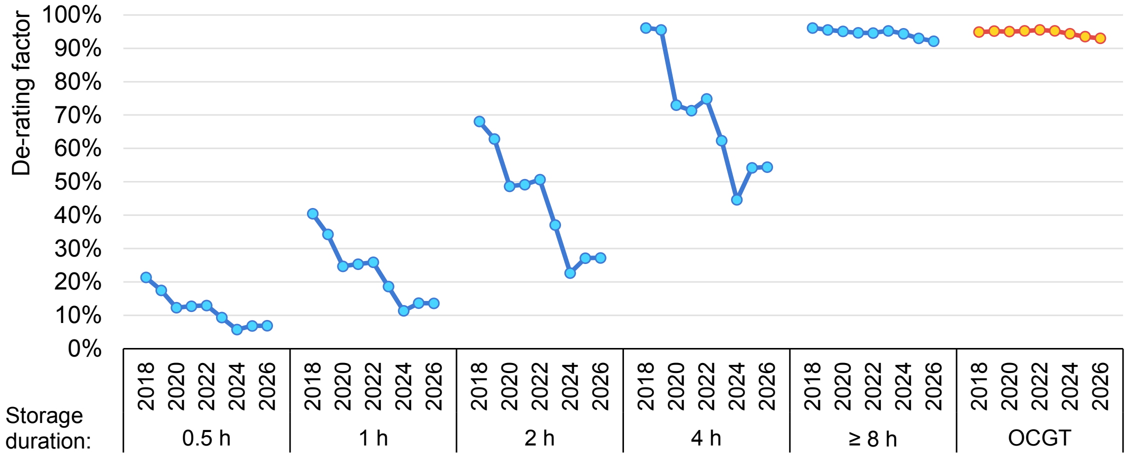
Capacity payments offer extra revenue, though value varies by accreditation method

Capacity payments are linked to the availability of resources and can provide an important revenue stream for battery storage projects. This is particularly relevant in markets where system adequacy or flexibility needs are not sufficiently reflected in wholesale electricity or ancillary services prices due to various factors such as specific designs and maturity of markets.

Where capacity mechanisms exist, the value that battery storage projects receive in these frameworks can differ significantly based on the specifics of the accreditation methodology. These methods assign an accredited capacity value reflecting a resource's reliable contribution to system adequacy during periods of highest system stress. For battery storage, this value is typically lower than nameplate capacity, reflecting limitations related to storage duration and uncertainty over state of charge at the onset of a stress event. In many schemes, these "derating factors" or "effective load carrying capability" are determined ex ante through modelling, with additional performance obligations or penalties applied ex post if assets underperform during realised scarcity events. Typically, shorter-duration battery storage tends to receive lower capacity credit, while longer-duration systems receive higher capacity credit and are treated more like other firm resources. As a result, peaking gas plants remain the most common source of firm capacity in many markets, even as storage begins to play a larger role. In California, for example, gas-fired plants continue to provide the largest share of accredited capacity in the resource adequacy programme, although batteries now account for just under one-fifth of accredited resource capacity.

In Great Britain, the Capacity Market credits storage based on its modelled reliability contribution, known as the de-rating factor, with providers required to deliver their contracted capacity when called during system stress events. This factor declines as duration decreases and is recalculated annually to reflect updated system conditions. In the United States, PJM applies an Effective Load Carrying Capability (ELCC) methodology that similarly adjusts accredited capacity depending on duration, reducing the value for shorter-duration systems. California's resource adequacy framework accredits storage based on the output it can sustain over 4 hours, with shorter-duration battery storage receiving lower capacity credit.

Assigned capacity contribution to reliability by storage duration and technology in Great Britain



Notes: The capacity contribution values shown here indicate the share of each technology's nameplate capacity that counts toward reliability in Great Britain's Capacity Market. These values, known as "de-rating factors," reflect how much dependable capacity each resource is expected to provide during system stress events. Values correspond to the T-1 Capacity Market auction (one-year ahead of delivery), which secures capacity closer to real-time needs. T-4 auctions are held four years in advance and may use slightly different de-rating factors based on projected system conditions.

Source: IEA analysis based on data from the Electricity Capacity Report.

Regulatory and market barriers can limit the uptake of utility-scale batteries

Tariffs and network charges can weigh on the economics of battery storage. In some jurisdictions, storage still faces “double charging”, paying use-of-system fees and levies both when charging and discharging, which can materially affect project economics. Some markets have introduced reforms to address this, such as Great Britain’s move in 2023 to apply a Balancing Services Use of System charge only to final demand, removing a key double charge on battery storage. Under the European Union’s Directive 2019/944, member states are required to ensure energy storage is not subject to double charging, including network charges. Several countries are moving to align with this directive, for example, France’s TURPE-7 framework will introduce an optional ‘injection-withdrawal’ tariff for storage from 1 August 2026 in eligible zones with predictable constraints.

Metering arrangements can add further cost and complexity, especially for co-located solar and storage projects. In Germany, for example, the regulatory treatment of electricity used for battery storage can differ depending on whether charging occurs from the grid or on-site renewable generation. For co-located projects, this can require additional metering and accounting to demonstrate compliance with charging and settlement rules, or restrictions on how storage can be charged, which raises compliance costs and limits operational flexibility. Recent regulatory changes are beginning to simplify these configurations, such as the Australian NEM’s Integrated Resource Provider model, which allows storage and co-located plants to register and participate as bidirectional units.

Export and import limits set the physical cap on how much power a site can deliver to and draw from the grid, while separate metering rules can require solar and storage to be metered and dispatched as distinct units, which may prevent them from using spare export headroom and can indirectly constrain total power delivery. For example, in Great Britain, distribution connections agreements specify Maximum Export/Import Capacity, and Distribution Network Operators may require compliance within these limits. Where locational price signals are weak or non-existent, batteries that could relieve congestion are not rewarded for doing so, meaning the value of deferred network investment is not reflected in project cash flows. Dynamic export limits or similar approaches may help address such issues.

Differences in market access and operational integration continue to shape how battery storage operates in electricity markets. While some systems now offer standard products for very fast services such as fast frequency response, others lack these, and inertia is often procured through specific tenders. Duration or bidding rules can also restrict simultaneous participation across services, within operational constraints, although recent reforms in several markets have sought to improve the ability to stack revenues across services. One example is ERCOT’s Real-Time Co-optimization Plus Batteries (RTC+B) market, which incorporates ancillary service dispatch into real-time energy dispatch. Introduced in December 2025, this is expected to save USD 1 billion per year through more efficiently harmonising battery availability across services. A further example is ISO New England's Day-Ahead Ancillary Service Initiative, which commenced operations from 1 March 2025. This initiative co-optimises energy and ancillary services in the day-ahead market, aligning energy schedules with reserve requirements and enabling battery storage to optimise participation in different market products. In Great Britain, the Office of Gas and Electricity Markets' (Ofgem) June 2025 decision establishing the market facilitator policy framework set out common rules and processes to align local and national flexibility markets, with the aim of reducing barriers to participation and service stacking.

In addition to various regulatory and market barriers mentioned previously, policy uncertainty is among the key factors influencing battery investment decisions. The timing and predictability of policy and market decisions can largely affect investment planning. Infrequent tenders, pauses during market reforms, and slow rulemaking create stop start signals that are hard for investors and supply chains to manage. Even where reforms are under way, the lag between consultation and implementation can stretch over several years, during which time projects face uncertainty around product definitions and accreditation rules.

Frequency and inertia products, and participation limits for storage across electricity markets

Market	Fast frequency service	Inertia products	Main participation limit
Great Britain	Dynamic Containment, ~1-second to full delivery (post-fault), procured day-ahead.	Inertia tenders via the Stability Market.	Under the Enduring Auction Capability, providers can split a unit's capacity across multiple response services in the same service window, but each MW can only be committed subject to physical capability constraints, with the auction co-optimising the allocation.
Germany	Frequency Containment Reserve (FCR), fully activated within 30 seconds.	Market based procurement of inertia for local grid stability, implemented via a fixed-price scheme, starting in January 2026.	FCR must be provided symmetrically and meet full activation and prequalification requirements, which can limit simultaneous provision across services.

Market	Fast frequency service	Inertia products	Main participation limit
Australia, NEM	Very Fast FCAS raise/lower, 1-second delivery, co-optimised with energy and other frequency services (5 second, 60 second, 5 minute).	Inertia contracts/trials for grid-forming assets; no NEM-wide spot product.	Co-optimisation with energy and state-of-charge management allows batteries to simultaneously offer full capacity (for a given state of charge) in each product category.
United States, ERCOT	Fast Frequency Response (FFR) with Responsive Reserve Service (RRS), trigger near 59.85 Hz, full response within 15 cycles.	No separate inertia product; managed operationally.	RRS-FFR requires deployment within 15 cycles at 59.85 Hz, sustain up to 15 minutes, and restoration within 15 minutes; Since December 2025, this is now co-optimised with energy and state of charge.
United States, CAISO	No dedicated FFR product. Fast Response obligations exist but are not a separate paid sub-second product.	No separate inertia product; addressed via planning and operations.	Resource Adequacy obligations and state-of-charge requirements limit simultaneous participation in other services or energy shifting.

Notes: Inertia is the instantaneous physical or emulated resistance of the system to a change in frequency. It limits the initial rate of change of frequency immediately after a disturbance and is often procured through dedicated inertia or stability services where these exist. Fast frequency response services consist of active control actions within one second to arrest frequency deviations and stabilise the system, before slower frequency control services restore frequency toward its nominal value.

Connection queues are becoming a major bottleneck in deployment for batteries

As highlighted in the Grids chapter, lengthy connection queues are becoming a bottleneck for utility-scale battery deployment. Despite rapid growth in installed capacity, the project pipeline remains far larger than operating capacity in many regions, and the pace of conversion from announcement to commissioning continues to lag.

The study process itself is a source of delay and uncertainty for battery storage developers. Such studies require substantial engineering resources and can trigger repeated restudies when there are material modifications, for example if an upstream project changes technology, capacity, location, or withdraws. These delays are particularly disruptive for battery storage developers, whose construction lead times are short and whose project economics rely on timely access to revenue streams.

Cost allocation for network upgrades can also be complex, with a small number of projects facing disproportionately high connection upgrade costs compared with the majority. Uncertainty around required grid upgrades, cost allocation and the timing of connection makes it difficult for battery storage developers to commit to investment schedules and can leave otherwise viable projects stranded. Recent changes in Australia deliberately shift some of these delay risks to the networks.

Environmental permitting and physical grid connection requirements are also a source of delay. Physical grid constraints frequently determine how quickly battery storage projects can move from design to operation. Long lead times for key grid components such as high-voltage transformers, switchgear, protection systems and substation equipment often determine the pace of connection works, sometimes exceeding the time required to install batteries and inverters. There may be siting constraints in urban load centres such as New York City, and construction schedules can be constrained by seasonal or environmental restrictions. Even if transmission level capacity limits are not reached, distribution networks may lack hosting capacity for large distribution-connected batteries without reinforcement. Where operators provide hosting-capacity maps and use standardised, time-bound connection procedures, siting is more efficient, and study timelines are more predictable.

Managing periods with high solar and wind output during low electricity demand

As the share of weather-dependent variable renewable energy sources such as solar PV and wind increases in many power systems, managing periods of very low or very high VRE output has become increasingly important for security of supply. This includes episodes of insufficient generation during VRE droughts, as well as times when excess production exceeds the system's ability to absorb it. In our previous Electricity 2025 report, we covered VRE droughts such as *Dunkelflaute* events in detail. Such events can pose challenges to the system, especially when the reduced VRE generation coincides with elevated electricity demand and insufficient dispatchable capacity.

The opposite situation, namely having high levels of VRE output during periods with very low electricity demand, brings with it other challenges. This phenomenon is sometimes referred to as *Hellbrise*, meaning "bright breeze" in German, reflecting conditions of abundant sunshine and wind. Excess electricity generation (also referred to as incompressibility or overproduction) amid high VRE output in low-demand periods, more common during holidays and weekends in off-peak months with longer daytime hours, can pose flexibility challenges with the need for additional downward flexibility. This is because electricity supply and demand needs to be continuously balanced for system stability, whilst some

VRE generation, particularly rooftop solar, is typically not price sensitive or not yet physically configured for curtailment. In some cases, such conditions may lead to reverse power flows from distribution grids to transmission grids, congestion and local overvoltage issues, requiring adequate planning and corresponding operational measures.

High VRE output lowers the net load[3], reducing the part of the load that would be met by dispatchable generators and/or imports. At the same time, some of the conventional generators need to be kept online to provide system services such as inertia, frequency and voltage regulation as well as due to technical constraints or cogeneration. Hence, under limited capability of storage, demand response and exports, very low net load levels may require increased curtailment and redispatch measures. At which net load level these measures intensify is highly system dependent. Having interconnections and the possibility for exporting electricity can provide a good degree of flexibility, though as weather conditions (hence solar PV and wind generation) are typically highly correlated across a wider area, this flexibility may not be always available at its fullest during such events.

Smaller systems with the ability to export a higher share of their generation to other regions regularly see very low, and even negative, net load levels (e.g. Denmark, South Australia). Whereas net load levels in larger systems with lower shares of power exports are typically higher (e.g. Brazil, the United Kingdom, Germany), though negative net loads may also be observed (as in the example of Germany). Moving forward, as the share of VRE continues to increase in many regions, it will be important to accompany this growth with a sufficient increase in flexibility in the system.

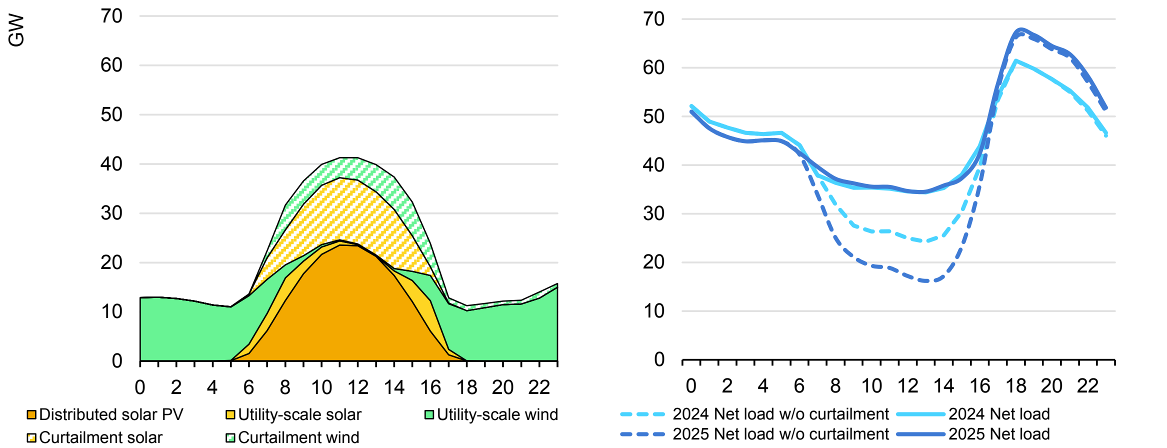
Very low net load periods can necessitate technical curtailment and targeted operational measures

Brazil experienced a very low net load instance on 10 August 2025, which was managed successfully without any impacts to reliability. The incident occurred on a Sunday with particularly low demand[4]. Around midday, distributed solar PV met almost 40% of the demand, or about 23 GW of the 58 GW load, pushing the system toward its minimum load limits and requiring rapid curtailment to maintain stability. The country's National Electric System Operator (ONS) reduced the production of hydropower and thermal power plants, as well as reportedly curtailing around 98% of the scheduled utility-scale wind and solar PV generation. High VRE generation amid limited transmission capacity and insufficient storage

[3] Net load refers to the part of the load that has to be met by dispatchable resources and/or imports, after the VRE output (solar PV and wind generation) is subtracted from the load. Net load can be negative, if the system is able to export the excess electricity.
[4] Demand was lower than usual due to many people being outside in good weather to celebrate Father's Day.

has been resulting in increased curtailment rates in Brazil. Curtailment rates of wind and solar PV in Brazil reportedly averaged 26% for the month of August 2025.

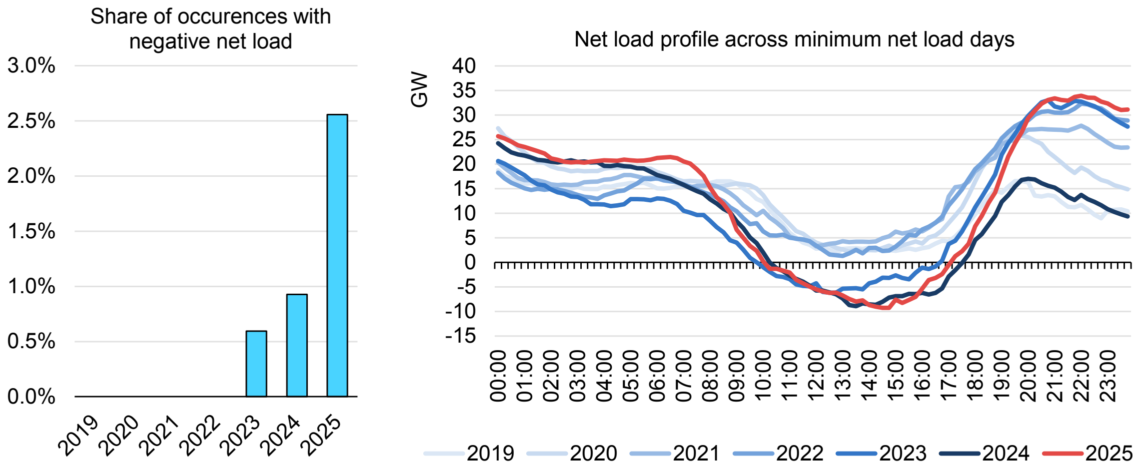
Hourly VRE generation, curtailment and net load during Father's Day in Brazil, 10 August 2025



Notes: Net load = load − (wind + solar PV generation). Curtailment includes both technical and economic curtailment.
Source: IEA analysis based on data from Operador Nacional do Sistema Elétrico (2025).

With VRE deployments accelerating, lower net load levels in many systems are being observed, with some systems starting to see negative net loads for the first time. Negative net load means that VRE generation exceeds demand while the excess is exported to interconnected neighbours. Negative net loads have been observed in **California** since 2023. Similarly, negative net loads have also been observed in **Germany** since 2023, as VRE growth outpaced the timid demand recovery following the energy crisis. In Germany, the typical "duck curve" shape has intensified, with midday dips becoming deeper, while evening ramps becoming more pronounced. At the same time, technical curtailment rates in the country have been increasing. This is especially noticeable for solar PV. While solar PV curtailments had been around 0.1-0.2 TWh before 2021, they have shown a rapidly increasing trend in recent years, rising to almost 1.5 TWh in 2024, or about 2% of the annual potential solar PV generation. While this is significantly lower than wind onshore curtailments at 4%, the strong growth trend is important to note, as it parallels the trajectory of declining net load.

Share of occurrences of negative net load (left) and net load profile during the days when the lowest net load over a year was observed (right), Germany, 2019-2025

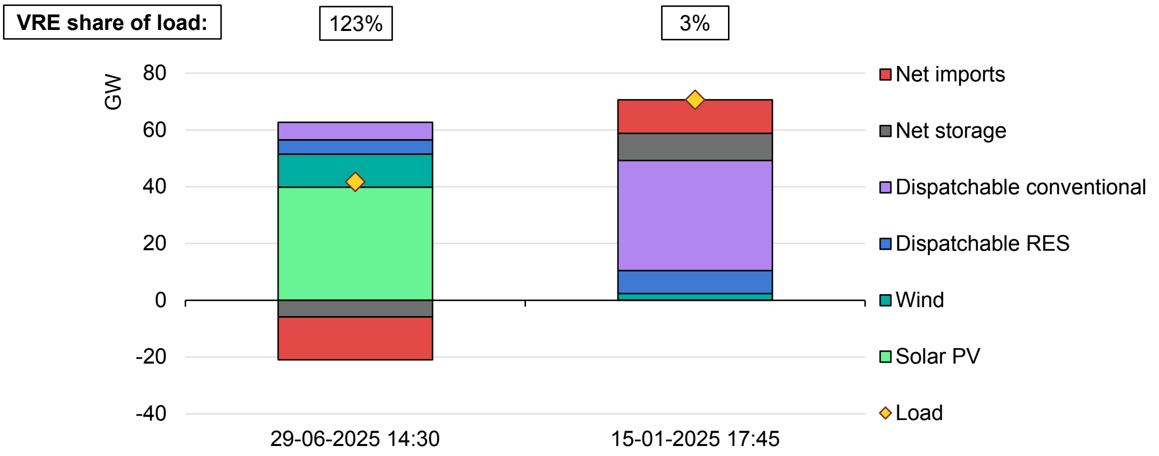


Notes: Net load = load − (wind + solar PV generation). Data has quarter-hourly resolution. Load includes storage charging.
Source: IEA analysis based on data from Energy-Charts.

Alongside falling net load levels with excess VRE generation, high shares of technically uncurtailable rooftop solar PV have become common in recent years in various systems, including in Germany. This can become a point of concern in instances when electricity demand in the system remains below the technically uncurtailable rooftop solar PV generation. As of the end of 2024, about 40 GW of the operational 100 GW of solar PV capacity in Germany was technically not controllable/curtailable. Very low net load instances in the country have been managed successfully so far without any impact to reliability, thanks to generation curtailments, exports and other flexibility measures.

Germany has introduced the Solar Peak Act in 2025, which aims to improve the technical ability to curtail distributed solar PV generation, among many other measures. The law caps grid feed-in for new PV installations with capacities ranging from 2 kW to 100 kW at 60% of their maximum feed-in capacity unless they have the intelligent metering systems installed for remote controllability by the grid operator. The law also suspends subsidies during negative price hours under certain conditions.

Electricity supply mix during a negative net load event in spring and during a VRE drought during winter in Germany, 2025



Notes: Negative net imports means net exports. Negative net storage means charging and positive net storage means discharging. Storage in Germany is predominantly pumped hydro storage. All the other renewable energy sources, excluding wind and solar PV, are categorised as dispatchable RES for the purpose of this analysis.
Source: IEA analysis based on data from Energy-Charts.

The relevance of excess VRE generation during low demand periods for security of supply planning is being increasingly recognised in Europe. The Belgian TSO Elia stated in its Summer Outlook 2025, for the second year in a row, that the likelihood of overproduction during sunny days with low consumption has increased amid surging solar PV capacity. Similarly, Amprion, one of the four TSOs of Germany, covers the phenomenon in its Market Report 2025, stressing the importance of market-side flexibility, storage and flexible operation of small-scale distributed PV. ENTSO-E introduced for the first time an analysis of excess renewable generation during low demand periods in its Summer Outlook 2025. The country feedback to the report included the suggestion of incorporating predefined controllability factors for renewable energy sources to the analysis, indicating that the controllability of VRE is considered as an important lever in such instances by the grid operators.

Reducing various regulatory, contractual and technical barriers can help unlock additional downward flexibility

Allowing for price signals that reflect the system situation is an important element for fostering flexible supply and demand. Very low net load periods are commonly associated with close to zero or even negative electricity prices on the wholesale market (in markets where they are allowed). These price signals are useful as they incentivise price-responsive generators (both conventional and renewable) to decrease their generation and consumers that are subject to price signals to increase their consumption. However, various generators and consumers may not be able to do so due to technical, regulatory or contractual reasons, which can contribute to system inflexibility. Addressing such barriers can help unlock additional flexibility for the system. A detailed discussion of these aspects was provided in our Electricity 2025 report.

Batteries, thanks to their rapidly declining costs, are expected to play an increasingly important role for providing downward flexibility to manage low net load periods. At the same time, greater demand response and smart charging of electric vehicles, alongside sector coupling such as power-to-heat, and hydrogen production via electrolysers, can provide additional demand for absorbing the excess electricity in a system-optimal manner. On the grids side, having interconnections with sufficient export capacity, if possible, is another essential lever to manage situations with overproduction. Also, various grid enhancing technologies (GETs), combined with increasing digitalisation of grids, can offer improvements in the monitoring and control of system-wide and local grid flexibility.

Controllable distributed PV helps manage low grid load as self-consumption grows

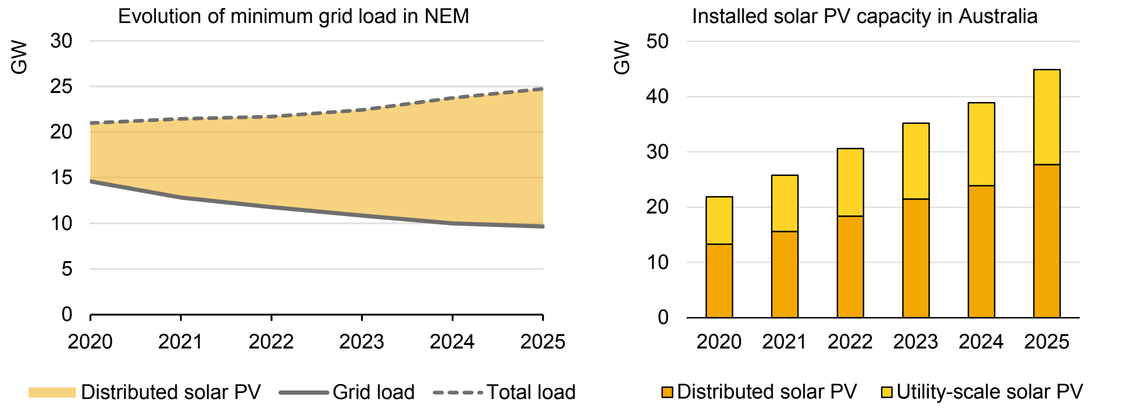
Another aspect relevant for various power systems is the rapid growth in self-consumption from rooftop solar PV. It is important to estimate the growth of self-consumption accurately as it can contribute to declining grid load, which typically needs to be kept above certain thresholds for stability. Reduced grid load levels can be observed particularly during off-peak months in low demand periods such as on weekends and public holidays amid sizeable self-consumption from distributed PV generation.

Grid load falling below certain levels is not desirable as the grid requires a minimum operational level of demand to maintain stable operation. Traditionally, conventional synchronous generators have supplied key system services such as fault current, voltage waveform stability, inertia, as well as voltage and frequency control. However, during very low-demand periods, there may not be enough operational headroom to dispatch these generators above their minimum output levels, limiting their ability to deliver essential security services. As a result, low grid load instances can introduce technical challenges that must be managed proactively.

Greater supply-side flexibility, more flexible loads, as well as increased storage for energy shifting and for ancillary services can help manage low grid load events. More widescale capability to control distributed solar PV and the ability to curtail the supply in the case of contingencies is another important lever. As the share of synchronous generators declines in the electricity mix, system strength can be reinforced by various technical measures such as deploying grid-forming inverters, and by installing synchronous condensers.

Australia's NEM is one example of a grid where this trend is pronounced, with new records being set every year for minimum grid load. According to Australia's AEMO, the new record for the minimum grid load in NEM was 9.7 GW in October 2025[5], 40% lower than what it was in 2020.

Minimum grid load in Australia, NEM (left), and installed solar PV capacity in Australia (right), 2020-2025



Notes: Minimum grid load is referred to as minimum operational demand by AEMO. Total load is grid load plus self-consumption, such as self-consumed rooftop solar. The minimum of total load each year is shown. Presented Installed solar PV capacity figures are not only for NEM but for all of Australia.
Source: IEA analysis based on data from AEMO.

AEMO, in its 2024 report, projected the minimum grid load[6] to continue declining by 1.2 GW per year out to 2029, as distributed PV penetration continues to rise. AEMO estimates 4.3 GW of minimum grid load is required to support the minimum generation levels for a stable system, where the threshold could increase to 7 GW at times of planned outages. Some of the main measures suggested by AEMO to manage the secure operation of the system in such events are to improve the flexibility of supply (both for conventional and renewable generators), as well as flexible loads, increased energy storage, and more widescale capability to curtail distributed PV in the case of contingencies. As a backstop measure, technical curtailment of rooftop solar PV has successfully taken place in South Australia in various minimum grid load events, although some other regions lack this capability. AEMO launched a process in December 2025 to receive expressions of interest from potential service providers to trial new technologies, or new

[5] The new minimum grid load of 9.7 GW record was broken at 12:00 on 4 October 2025 on Saturday, 4% lower than the previous record in 2024. During this instance, distributed solar PV supplied 58% of total demand. In general, AEMO estimates that for each 1 MW of installed distributed solar PV, minimum grid load reduces around 0.7-0.8 MW.
[6] Minimum grid load is referred to by AEMO as the minimum operational demand.

applications of existing technologies, that can expand the range of solutions available for minimum grid load.

Encouraging higher consumption during periods of surplus solar PV generation and low grid load can also significantly support the management of system imbalances. Time-of-use tariffs and similar measures that encourage electricity consumption during periods of abundant VRE generation – when prices are typically lower – can help manage instances of very low grid load. In Australia, the government has announced the Solar Sharer Offer, which is scheduled to begin on 1 July 2026 in New South Wales, South Australia and South East Queensland. Under this scheme, retailers would be required to offer at least three hours of free electricity around midday to encourage consumption during periods of high solar output, supporting grid load while also helping shift demand away from more expensive evening peaks.

Emissions

Electricity sector emissions are increasingly decoupling from demand growth

Global CO_2 intensity of electricity, which measures the amount of carbon dioxide emitted per unit of electricity produced worldwide, has been falling as the share of low-emissions sources – renewables and nuclear – continues to rapidly expand in the generation mix. Over the past decade, the improvement in global CO_2 intensity has been significant, declining by 14% to 435 g CO_2/kWh in 2025. Nonetheless, emissions from electricity generation rose by 13% during the same period, to about 13 900 Mt CO_2, accounting for around 40% of worldwide emissions. Mitigating emissions from fossil fuelled-fired generation with clean energy sources amid rising electricity demand remains a key challenge for the power sector. This chapter provides an overview of emerging trends in global emissions from electricity generation and the evolving trajectory of its CO_2 intensity.

CO_2 emissions from electricity generation are forecast to plateau through 2030

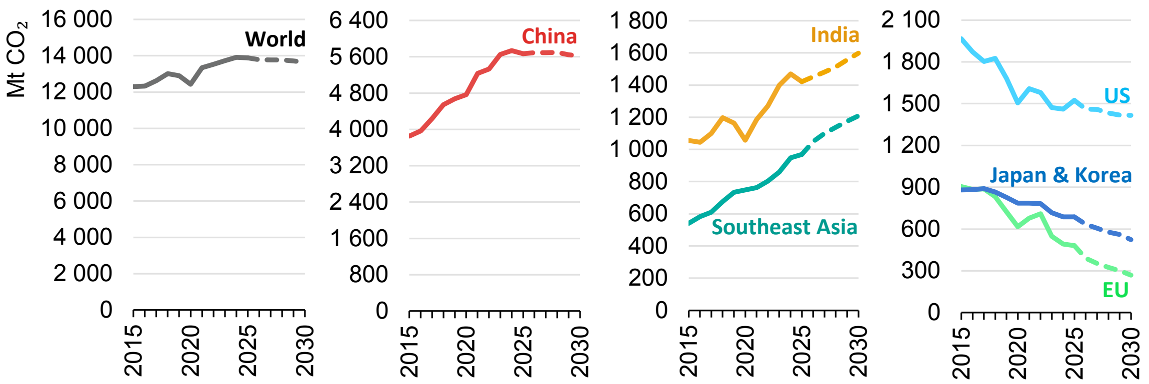
In 2025, global emissions from electricity generation remained flat, after increasing 1.5% and 1.4% in in the previous two years, respectively. Even with strong gains in electricity demand, growth in power sector emissions is showing marked signs of slowing down as fossil-fired generation is constrained by the rapid deployment of renewables and rising nuclear power generation. As this trend continues, we forecast global emissions from power generation to plateau over our 2026-2030 outlook period due to significant increases in clean energy sources, despite electricity demand growth of an average 3.6% annually – a sharp acceleration from the 2.8% pace of the past decade. Economic shocks and deviations from normal weather conditions, such as intense heat waves, cold spells or low water availability for hydropower generation, can cause an increase in emissions in individual years. However, the transformative trend of low-emissions energy sources limiting fossil-fired output is expected to remain resilient.

In 2025, reduced emissions from electricity generation in India and China were largely offset by increases in the United States, other Asia Pacific (excluding India and China), Eurasia and the Middle East. India saw a decline of 3.3% y-o-y as coal-fired generation contracted amid moderate demand growth and strong renewables expansion. China saw a slight decrease of around 1%. In the

European Union, emissions from electricity generation fell by 2.2%. By contrast, US emissions increased by 4.3% due to higher coal-fired generation.

Between 2026 and 2030, China's CO_2 emissions from electricity generation are forecast to fall on average by 0.2% per year as low-emissions energy sources constrain coal-fired output, and despite continued robust electricity demand growth. Following the decline in 2025, India is forecast to see emissions rise by an annual average of 2.4%, as demand posts steady growth through 2030, with coal remaining the dominant source of supply in the power sector. The United States is expected to resume its declining trend in emissions, at an average annual rate of 1.4%. In the European Union, emissions are projected to drop substantially, by an average 11% per year over the forecast period.

CO_2 emissions from electricity generation in selected regions, 2015-2030



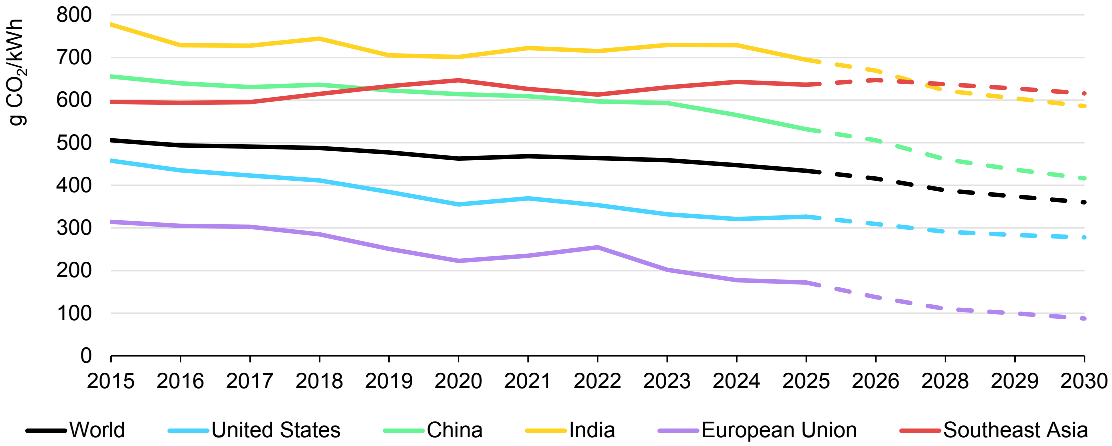
Note: Data for 2026-2030 are forecast values.

Global CO_2 intensity decline accelerates as low-carbon generation rapidly expands

Global CO_2-intensity from electricity generation contracted by an estimated 3% in 2025, after a 2.6% reduction in in 2024. An increasing share of renewables and robust output in nuclear energy generation are driving this trend. We forecast CO_2 intensity to fall even faster over our forecast period, at an annual average rate of 3.7%, down from 435 g CO_2/kWh in 2025 to 360 g CO_2/kWh in 2030.

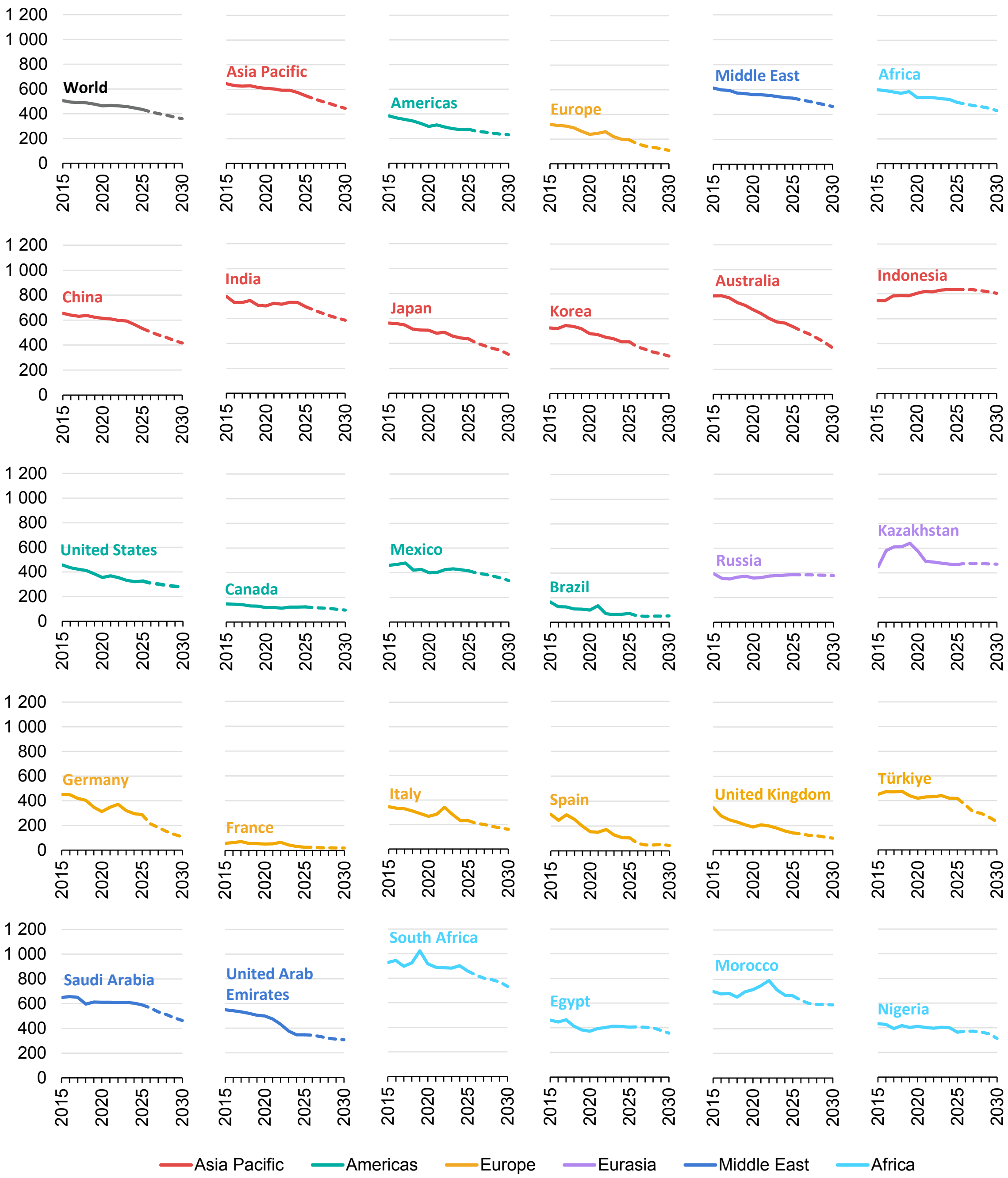
Many regions are expected to register substantial declines in CO_2 intensity in the 2026-2030 outlook. The European Union is forecast to post the sharpest fall in emissions intensity from electricity generation, with an annual reduction of around 13%, dropping from 170 g CO_2/kWh to 90 g CO_2/kWh over the period. Similarly, China is forecast to record an average decline rate of 4.8% per year, though from significantly higher levels of 530 g CO_2/kWh in 2025 to 415 g CO_2/kWh in 2030, with the CO_2 intensity approaching the global average. The United States is projected to see a 3.2% average annual reduction. CO_2 intensity in India is expected to fall by 3.4% annually, from 695 g CO_2/kWh to 585 g CO_2/kWh. However, Southeast Asia sees a muted average decline of 0.7% over the forecast period, from 640 g CO_2/kWh to 615 g CO_2/kWh. Hence, over the forecast period, India's emission intensity is set to fall below that of Southeast Asia, with the latter becoming the highest emission intensity region.

CO_2 intensity of electricity generation in selected regions, 2015-2030



Note: CO_2 intensity is calculated as total CO_2 emissions divided by total generation.

CO_2 intensity of electricity generation in the world, by selected countries, and regions (g CO_2/kWh), 2015-2030



Notes: CO_2 intensity is calculated as total CO_2 emissions divided by total generation. Data for 2026-2030 are forecast values.

Prices

Affordability and competitiveness take centre stage

Average wholesale electricity prices in 2025 rose year-on-year in multiple regions and countries, including Europe and the United States, while others such as India and Australia saw lower prices compared to 2024. Looking at electricity prices for energy-intensive industries, significant variations across regions remain. EU electricity prices for energy-intensive industries stayed elevated in 2025, again averaging over twice US levels and nearly 50% above those in China, similar to 2024, adding competitive pressure.

At the same time, negative wholesale electricity prices became more common across many markets. Exceptions include the Nordic region in Europe and California in the United States, which recorded year-on-year declines in the numbers of negatively priced hours in 2025. These reductions were driven by more price-responsive supply and demand, alongside the growing deployment of battery storage, which helped absorb excess generation and smooth short-term imbalances.

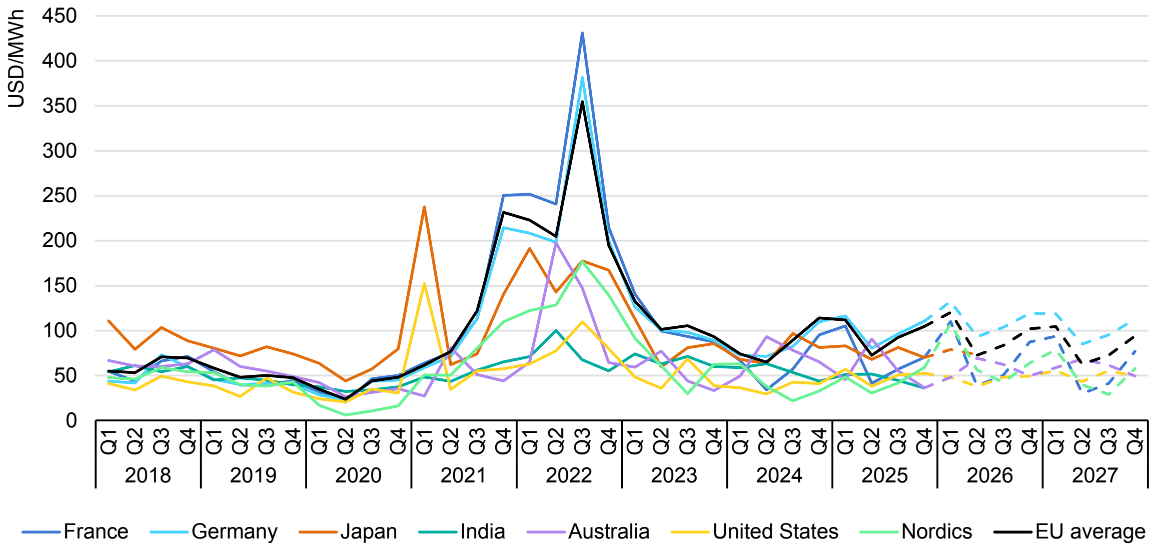
Affordability remains a concern, as household electricity prices in many countries have risen faster than incomes and inflation since 2019. While energy-related price components have fallen from crisis highs, they remain above 2019 levels, and non-energy charges – such as networks, taxes and fees – continue to take up a large share of bills. Electricity is also often taxed more heavily than natural gas, raising its relative cost and weakening incentives for households to electrify heating, cooking and hot water. As a result, policy makers are increasingly focusing on market and regulatory reforms to improve affordability while still ensuring prices reflect costs and encourage demand-side flexibility.

Wholesale prices continue to differ across regions

Many markets recorded wholesale prices increased year-on-year in 2025 amid higher gas prices, following declines in 2024 compared to 2023. The average EU wholesale price in 2025 was up around 10% y-o-y to about USD 95/MWh, in line with the 9% increase in the Title Transfer Facility (TTF) natural gas price at the trading hub in the Netherlands. This was also supported by higher EU Emissions Trading System (EU-ETS) prices, which rose by 15% y-o-y, averaging around EUR 75/t CO_2 in 2025. Average EU wholesale electricity price remained the highest among the markets analysed in 2025 – roughly twice that of the United States and India, and markedly above levels in Australia (+65%) and Japan (+25%). Cold snaps in January 2026 boosted heating and electricity demand, contributing to higher natural gas spot and forward prices. Higher gas prices, in turn, put upward pressure on power futures. EU futures prices as of 26 January 2026 averaged around USD 95/MWh for 2026, broadly in line with 2025 levels, before easing to roughly USD 85/MWh in 2027.

The average wholesale electricity price in Germany was 20% (+14% in EUR/MWh) higher y-o-y in 2025, at an average USD 100/MWh. Alongside higher gas prices compared to 2024, the significant drop in wind energy production due to less favourable weather conditions also contributed to the higher levels. This resulted in increased gas and coal-fired power generation in order to meet the demand, which put upward pressure on electricity prices. German futures contracts for 2026 point to a 10% increase, while the 2027 contracts indicate an easing to similar price levels in 2025. The premium in German futures over French prices remains in place, averaging more than USD 40/MWh.

Quarterly average wholesale electricity prices for selected regions, 2018-2027



Notes: Prices are in nominal values, converted to USD based on the average exchange rate of the quarterly period. Prices for Australia and the United States are calculated as the demand-weighted average of the available prices of their regional markets. Continuous lines show historical data and dashed lines refer to forward prices.

Sources: IEA analysis based on data from RTE (France) – accessed via the ENTSO-E Transparency Platform; Bundesnetzagentur (2026), SMARD.de; the Australian Energy Market Operator (AEMO), 2026, Aggregated price and demand data; EIA (2026), Short-Term Energy Outlook, January 2026; IEX (2025), Day-Ahead Market; EEX (2026), Power Futures; ASX (2026), Electricity Futures © ASX Limited ABN 98 008 624 691 (ASX) 2026. All rights reserved. This material is reproduced with the permission of ASX. This material should not be reproduced, stored in a retrieval system or transmitted in any form, whether in whole or in part, without the prior written permission of ASX. Latest update: 26 January 2026.

In **France**, average wholesale electricity prices rose 8% y-o-y to USD 70/MWh in 2025 (+4% in EUR/MWh). Even though hydropower was almost 20% lower in 2025, robust nuclear output helped moderate price rises. French futures prices for 2026 are broadly aligned with 2025 levels, while contracts for 2027 were trading at around 10% below the 2025 average.

Wholesale electricity prices in the **United Kingdom** increased by 18% y-o-y in 2025 (+14% in GBP/MWh), to an average of USD 105/MWh. Colder weather and lower wind generation in early 2025 had a significant market impact, resulting in both higher output from gas-fired generation and higher wholesale prices. Futures prices for 2026 and 2027 indicate price levels broadly similar to those observed in 2025.

Wholesale electricity prices in the **Nordics** remained the lowest in Europe in 2025, despite having increased by 15% y-o-y to USD 45/MWh (+10% in EUR/MWh). Market data show that average futures prices are close to USD 70/MWh for 2026, before easing to about USD 50/MWh in 2027. The Nordics are the only market in Europe with comparable price levels to those in the United States.

In the **United States**, wholesale electricity prices rose on average by around 30% y-o-y to USD 50/MWh in 2025. Higher natural gas prices compared to 2024 pushed up US wholesale electricity costs. US Henry Hub natural gas spot prices were up by about 56% y-o-y, but lower than in 2021. While summer temperatures on average were milder than in the previous year, with 6% less cooling degree days (CDD) in 2025, colder-than-normal winter weather led to a 9% increase in heating degree days (HDD), contributing to higher prices. The Energy Information Administration's (EIA) Short-Term Energy Outlook price projections published in January 2026 indicate an average price level of about USD 45/MWh in 2026 and USD 50/MWh in 2027.

In **Japan**, wholesale electricity prices declined slightly in 2025 by 2% y-o-y (-3% in JPY/MWh), averaging about USD 75/MWh. The upward pressure from slightly higher gas prices was more than offset by an increasing share of low-marginal-cost nuclear and renewable generation. Although rising spot LNG prices increased generation costs in the first half of 2025 – pushing wholesale prices higher – market conditions eased in the second half of the year as LNG supply availability improved. On average, Platts JKM prices were around 2% higher in 2025 compared with 2024.

In 2025, **Australian** average wholesale electricity prices fell by around 20% y-o-y to USD 57/MWh (-18% in AUD/MWh), even though periods of extreme weather, including heatwaves in the southeast of the country, occasionally led to price surges. Despite growth in overall electricity demand, higher renewable generation and lower market volatility contributed to the fall in wholesale prices. Rising battery output, as new storage capacity came online, helped mitigate price surges by displacing more expensive gas and coal generation during peak demand periods. Futures prices for 2026-2027 indicate a price level around USD 60/MWh.

In **India**, wholesale electricity prices declined by 16% y-o-y in 2025 (-13% in INR/MWh, [Indian rupees/MWh]), to an average of USD 46/MWh. A drop in seaborne thermal coal prices to a four-year low in the first half of the year eased input costs for coal-fired generation, despite a mild price recovery later in 2025. Increased availability from thermal and renewable capacity additions, together with strong hydro output, strengthened market liquidity and exerted downward pressure on prices. The early arrival of the monsoon, and lower overall May-August temperatures versus a year earlier, led to limited demand growth. Robust output from low-emissions sources contributed to near-zero prices during several time periods on 25 May and again on 25 August.

Negative wholesale pricing trends diverged across markets in 2025

The occurrence of negative wholesale electricity markets continued to increase in many markets in 2025, though some diverging regional trends were observed. Negative prices broadly signal a lack of flexibility in the system due to technical, regulatory or contractual reasons, particularly during times of low electricity demand and abundant electricity generation. Negative prices are a market signal indicating a need for more flexibility. A comprehensive analysis on the reasons behind rising occurrence of negative prices can be found in a dedicated section in our Electricity 2025 report.

Many European markets continued to see more frequent negative prices, with the proportion of hours with negative prices reaching 6% in 2025 in countries such as France, Germany, the Netherlands, and Spain – compared to around 3-5% in 2024. Spain recorded the largest year-on-year increase, with the number of negatively priced hours doubling. This was followed by France, where these hours rose by 45% y-o-y, while in Germany and the Netherlands they were each about 25% higher.

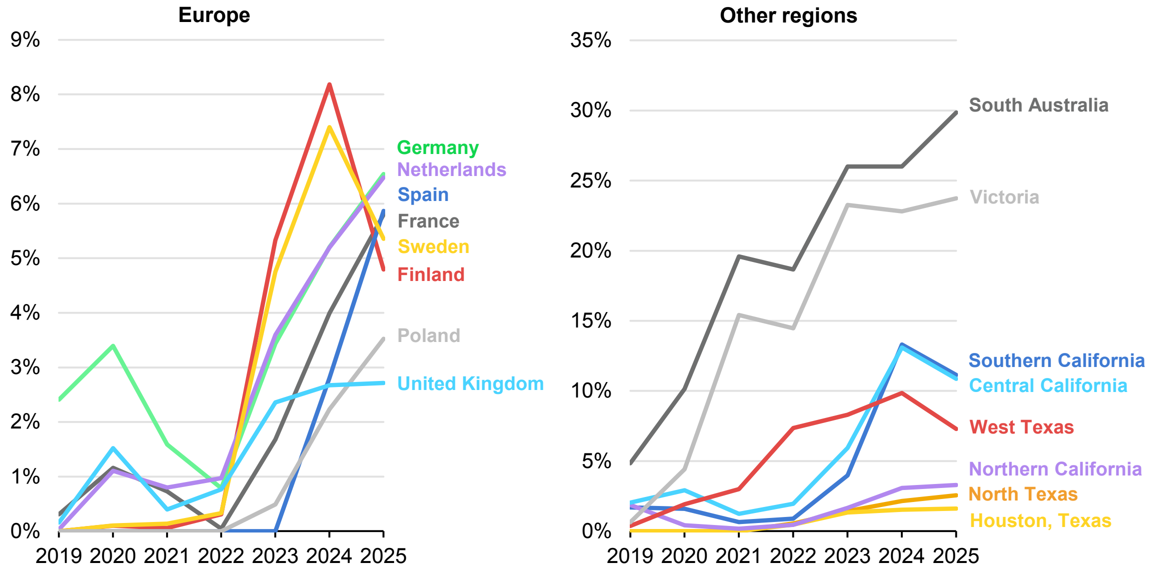
The frequency of negative prices continued to rise in some Australian regions, such as South Australia and Victoria. This was largely due to increases in wind generation, particularly during the night. AEMO also reported that during negative price events in Australia's NEM in 2025, prices were closer to AUD 0 /MWh on average amid lower prices for largescale green certificates.

Several regions saw a reversal of the trend of increasing negative prices. In Europe, Finland had the highest number of negatively priced hours in 2024 at 8% of the time, followed by Sweden with 7%. In 2025, both countries observed a significant drop in negative pricing, with the number of hours declining by about

40% in Finland and by almost 30% in Sweden. This may be due to a range of structural factors, including the introduction of flow-based market coupling used for calculating and allocating cross-border electricity trading capacity, growth in storage, and generation becoming more price-responsive. In addition, this may be driven by Finland's continued electrification of district heating, up around 70%, from 1.5 TWh in 2024 to 2.6 TWh in 2025, which can be price responsive.

In the United States, California and Texas also recorded declines in the frequency of negative price events. This shift may be linked to rising electricity demand and, in particular, to the rapid expansion of battery energy storage systems in both states − reflected in the marked increase in average hourly battery charging around midday.

Fraction of negative hourly wholesale electricity prices in selected regions, 2019-2025



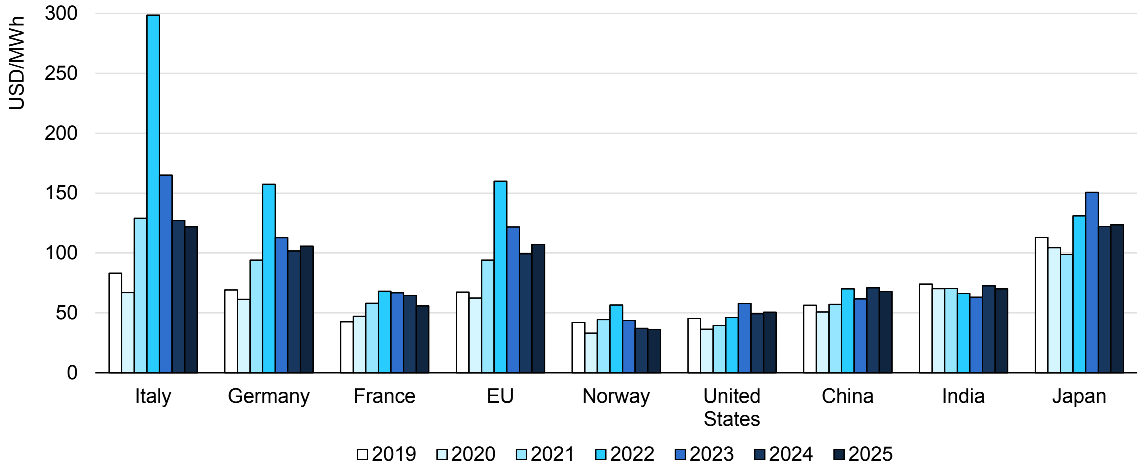
Notes: Southern California corresponds to area SP15 in the state's zonal regions, Central California to area ZP26 and Northern California to area NP15. In Spain, negative electricity prices on the day-ahead market were permitted in December 2023 following the implementation of updated rules on the operation of electricity markets. For South Australia and Victoria, five-minute interval prices were converted to hourly averages to enable comparison.

Source: IEA (2025), Real-Time Electricity Tracker (data explorer).

Price gaps for energy-intensive industries persist across regions in 2025

In 2025, electricity prices for energy-intensive industries remained broadly stable across our tracked regions compared to the previous year. In the European Union, after two years of significant declines since their 2022 peak, prices rose by over 7% in 2025, mainly due to an 8% increase in wholesale prices. As a result, EU prices for these large industries are stabilising at around 1.6 times the levels seen in 2019, putting pressure on competitiveness, particularly as they are more than double the prices in the United States and more than 50% higher than in China and India. These trends can have an impact on employment as well, and the European Central Bank estimates that a hypothetical permanent rise of 10% in electricity prices can lead to a 2% loss of employment in energy-intensive industries, affecting specific areas such as Germany's southern region and the Ruhr urban area, and northern Italy.

Estimated final electricity prices for large industrial customers in energy-intensive industries, 2019-2025



Notes: Values for 2025 are preliminary. This analysis considers electricity prices of industries with greater than 150 GWh of annual electricity consumption for European countries, based on Eurostat data. Electricity price compensation is included for countries that participate in the EU-ETS. For the calculation of the maximum possible state aid for electricity price compensation in the European Union, the analysis assumes that the specific product has an electricity consumption benchmark of 0.8 and that the company in question receives the maximum possible state aid once this benchmark is incorporated into the maximum aid calculation. The final electricity price for the United States is based off the final electricity price for industry in Texas. The prices for the United States and China are indicative of the average reported prices, while prices for individual industries depend on their energy consumption levels and where they are located.

Europe steps up its efforts to reduce prices for energy-intensive industries

In February 2025, the European Commission (EC) launched the Action Plan for Affordable Energy, in which Pillar I focuses on lowering electricity prices through network charges, increased demand-side flexibility, lower taxation, reduced exposure to natural gas price volatility, implementation of long-term contracts, and enhanced energy efficiency. Noting that following the energy crisis, prices remained much higher compared to various other regions and that energy-intensive industries needed a relief quickly, the European Commission set seven key actions to bring down energy prices in October 2025. Among these actions, the commission urged member states to make full use of the Clean Industrial Deal State Aid Framework (CISAF), allowing more flexibility with state aid rules. CISAF allows a temporary subsidy of up to 50% of the yearly average wholesale market price in the bidding zone where the industry is connected. This applies to no more than 50% of yearly consumption, resulting in a reduced price but not below EUR 50/MWh for the eligible consumption, and at least 50% of the aid must be allocated to new or modernised assets such as renewable generation, storage or demand-side flexibility.

In Italy, the Energy Release 2.0 mechanism was approved by the Ministry of Environment and Energy Security in November 2025. The measure supports an industrial electricity price of EUR 65/MWh through a two-way CfD, for a total annual consumption of 24 TWh, assigned to participants based on the results of a competitive process. Among other requirements, the mechanism obliges selected industries to develop new solar PV, wind or hydro capacity equal to at least twice the capacity needed to generate over 20 years the amount of electricity advanced under the scheme. The benefit is expected to last three years.

In Germany, the government announced a subsidised industrial electricity price of EUR 50/MWh to be retroactively applied from 1 January 2026. Approximately 2 000 energy-intensive industrial companies in Germany, with a total annual consumption of around 100 TWh and a current electricity price of EUR 70-110/MWh, would benefit from this subsidy, with an estimated total support volume of EUR 3.3 billion. The support scheme is designed for a duration of three years, for 50% of the consumption of these companies during the period, and at least 50% of the funds received must be reinvested in decarbonisation. However, CISAF excludes double funding, therefore the around 350 companies eligible for EU-ETS compensation will need to choose between the two subsidies.

Beyond the European Union, the UK government introduced various measures to support energy-intensive industries through its Modern Industrial Strategy 2025 and the British Industrial Competitiveness Scheme. This scheme aims to reduce electricity prices by up to 25%, or GBP 40/MWh, from 2027 for over 7 000 businesses by granting exemptions from key electricity levies, including the renewables obligation, feed-in tariffs and the capacity market. In addition, around 500 eligible industries in sectors such as steel, cement, glass and chemicals will see their existing network charge exemptions increased from 60% to 90% starting April 2026, reportedly saving up to GBP 420 million annually.

How do industries procure their electricity in China?

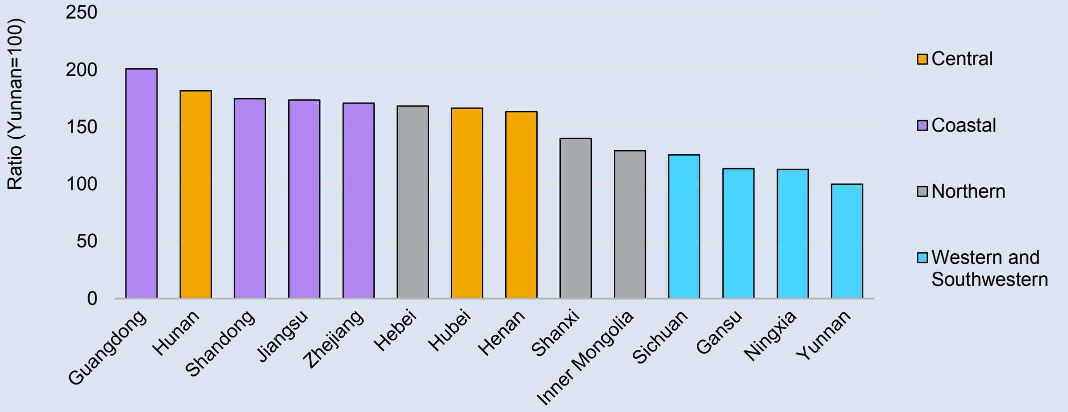
While some of China's largest industrial consumers procure their electricity by trading directly in wholesale markets, many use the proxy pricing mechanism, particularly in provinces where wholesale markets are not yet fully developed or access is limited. Introduced by the National Development and Reform Commission (NDRC) in October 2021, the proxy pricing mechanism represented a key milestone in China's power market reform. Developed in response to the severe power shortages and coal price surges that year, it replaced the previous fixed-tariff system of electricity prices for industries and businesses in China.

Under this system, power retailers in China act as purchasing agents for industries and businesses which do not participate directly in the wholesale market. In this case, retailers procure electricity through competitive market trading in each province and resell it to industries at a market-linked proxy price.

Proxy prices reflect the weighted average cost of market purchases plus regulated transmission fees and government surcharges. Since they aim to reflect trends in wholesale markets, levels vary by province and region, reflecting differences in electricity demand, resource availability, and market conditions. Initially, proxy purchases were conducted via monthly listings but were later replaced by centralised market auctions. Proxy prices are recalculated monthly and applied to all users of similar type and voltage level. The mechanism also provides flexibility for users to switch between direct market participation and proxy pricing, although those returning to the proxy system after direct trading typically incur a temporary 50% price premium to discourage frequent switching.

Given that proxy prices in the country are based on trends and levels of each province's wholesale market, their values show a west-to-east gradient reflecting inexpensive generation in resource-rich inland provinces versus high demand and fuel costs in coastal regions. Industries in Western and Southwestern provinces, particularly in Yunnan, Sichuan and Gansu, benefit from large shares of hydropower and VRE, in addition to cheap coal, which provide a competitive advantage. Northern provinces are generation-surplus regions with abundant coal, resulting in low prices in Inner Mongolia and Shanxi, which are core exporters of electricity and home to China's heaviest industries, while Hebei's prices are slightly higher given limited coal reserves and a mild supply deficit. Proxy prices in central China provinces are closer to the national average given their mixed supply and more diversified demand. Finally, industries in coastal Chinese provinces face the highest proxy prices in the country, with Guangdong prices twice as high as in Yunnan in the January-September 2025 period, reflecting stronger demand, import dependence, transmission constraints, and exposure to gas and coal markets.

Electricity proxy prices in select provinces, China, January-September 2025

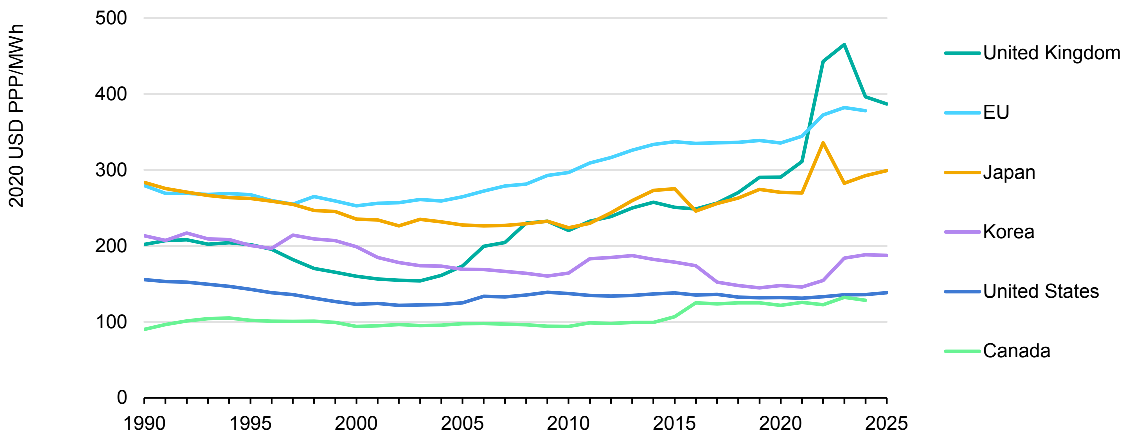


Notes: Values are expressed as a ratio where proxy prices of Yunnan equal one hundred. Inner Mongolia values reflect proxy prices of its Western grid.

Residential electricity prices remain elevated across many regions

Electricity prices for residential consumers have been subject to significant variations across regions in the last five years, as geopolitical events, wholesale market trends, rising network costs, and relief measures drove high volatility. Record level prices were observed between 2022 and 2024 in markets such as the European Union, the United Kingdom, Japan and Korea. Although prices have since retreated from their peaks, they remain elevated in many countries, affecting affordability and posing a risk to the expansion of electrification of end uses such as space cooling and water heating.

Electricity price for households in selected countries and regions, 1990-2025

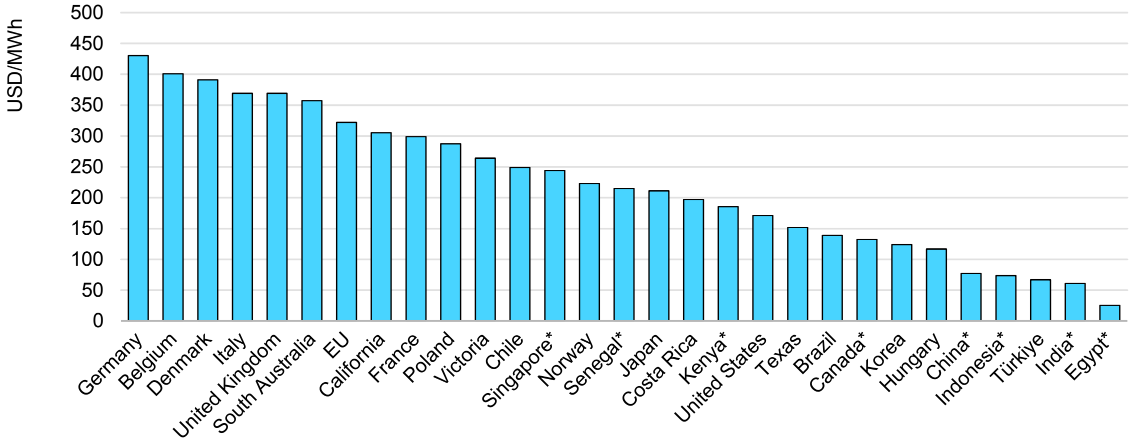


Note: Data for 2025 are preliminary. Complete data for the European Union and Canada were not available at the time this report was published; consequently, data for these regions are presented only up to 2024.
Source: IEA analysis based on data from IEA Energy Prices (2025).

In the first half of 2025, the average EU residential price was USD 322/MWh and remained broadly flat compared to 2024, although trends varied significantly between member countries. Prices increased by 9% or more in Austria, Spain, Sweden, Poland and Ireland, among others, but fell by 6% or more in France, Denmark, Finland and Slovenia. During H1 2025, average EU residential prices were 34% higher than in 2019, with large relative increases observed in Poland (+89%), Czechia (+81%), Lithuania (+68%), France (+44%), and Italy (+42%).

In the United States, electricity prices for households rose by 5% y-o-y in 2025, with an average of USD 174/MWh in the first eleven months of the year. Nationwide prices are now 32% higher than in 2019 but have increased more significantly in states like California (+68%), New York (+47%) and Illinois (+38%).

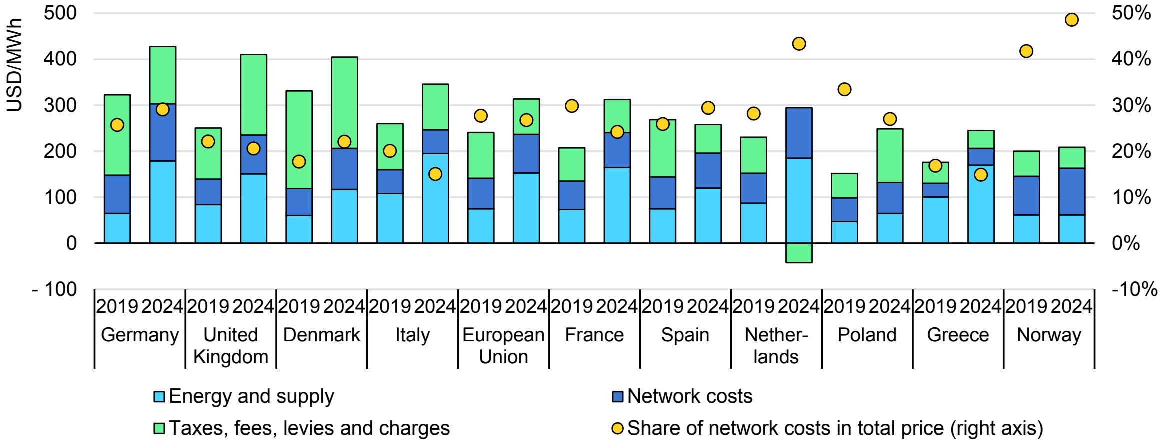
Electricity prices for households in selected regions, countries and states, H1 2025



Notes: Values for countries marked with an asterisk (*) refer to full year 2024, due to H1 2025 data being unavailable at the time of publication. The value for California includes the 2025 Climate Credit. Prices reflect annual consumption levels from 2 500 kWh to 4 999 kWh, where available.
Source: IEA analysis based on data from IEA Energy Prices (2025), Eurostat (2025), US EIA (2025), California Public Utilities Commission (CPUC), (2025), Australian Energy Regulator (AER), (2025), Victoria, Australia Essential Services Commission (ESC), (2025).

One of the key components of residential electricity prices, together with energy and supply costs, taxes, levies, fees and charges, is network costs. This component charge covers transmission and distribution network tariffs and losses, as well as system, service and metering costs, among others. Between 2019 and 2024, network costs increased by 30% on average in the European Union, and by 53% in the United Kingdom. Despite this growth, the share of network costs in electricity prices for households has decreased slightly on average in the European Union, from 28% in 2019 to 27% in 2024, and in the United Kingdom from 22% to 21%, as other price components grew faster.

Electricity prices for households by component and share of network costs in total price, by selected country and region, 2019-2024



Sources: IEA analysis based on data from Eurostat (2025), UK DESNZ (2025). Negative values in the taxes, fees, levies and charges component reflect government interventions such as subsidies, tax reductions and rebates to shield households from surging electricity prices, demonstrating strong support measures.

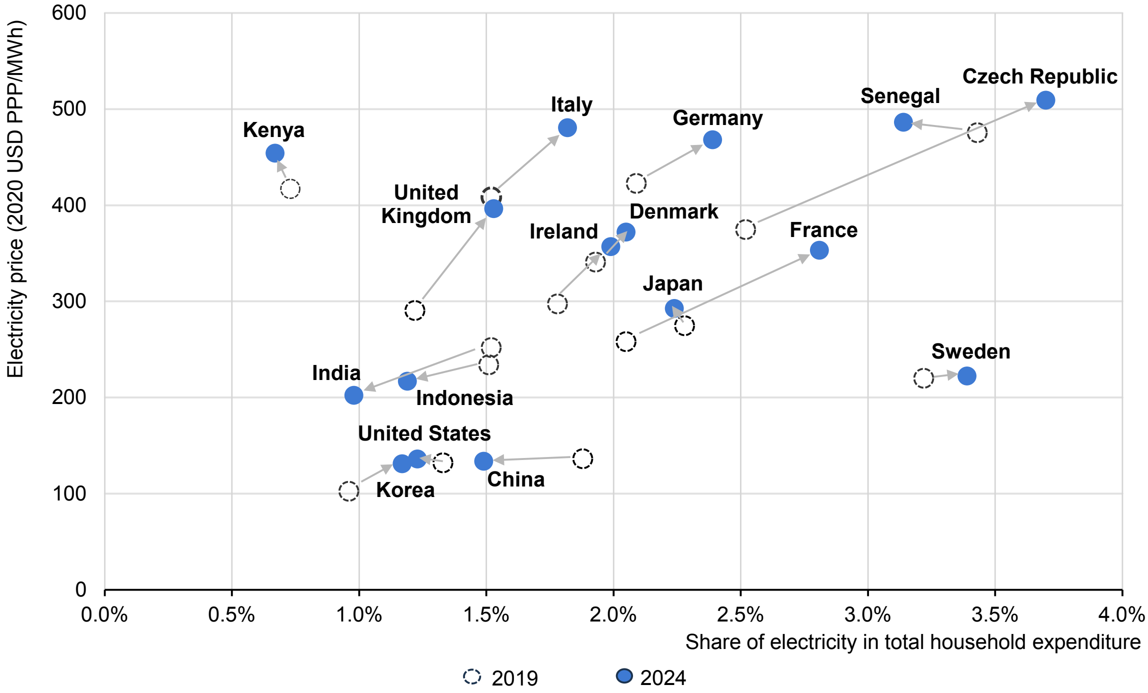
Affordability concerns persist as electricity price increases outpace income growth and inflation

The rise in electricity prices for households has outpaced growth in income and general inflation rates since 2019 in many countries, leading to costlier bills for residential consumers. Between 2019 and 2024, electricity prices for households increased by 36% on average in the European Union and by 26% in the United States. During the same period, annual net earnings for a two-earner couple with two children increased by 25% in the European Union, and by 23% in the United States, while inflation rates during this period were 22% and 23%, respectively.

Household demand for electricity is generally price-inelastic, meaning it responds only modestly to variations in retail prices given the essential nature of many end uses (like lighting, refrigeration, cooking, electronic devices). Therefore, increases in prices tend to translate into higher household expenditure on electricity, especially in the short term.

Recent changes in electricity prices have altered the weight of electricity in total household expenditure, but the effect varies by region. In advanced economies such as many EU countries, the United Kingdom, or Korea, recent increases in electricity prices, when adjusted for inflation and purchasing power parity, have led to a rise in the share of electricity in total household expenditure. By contrast, the United States (on average) and Japan exhibited a mild decrease in this share. In developing economies such as China, India, Indonesia, Kenya and Senegal household expenditure on electricity grew more slowly than overall household expenditure due to relatively stable residential electricity prices. It should be noted that while our analysis across all the regions looks at the average trends, the impact on affordability depends highly on the income levels of individual households, with the lower and moderate-income households typically more disproportionately affected.

Electricity price versus share of electricity in total household expenditure in selected countries, 2024 vs. 2019



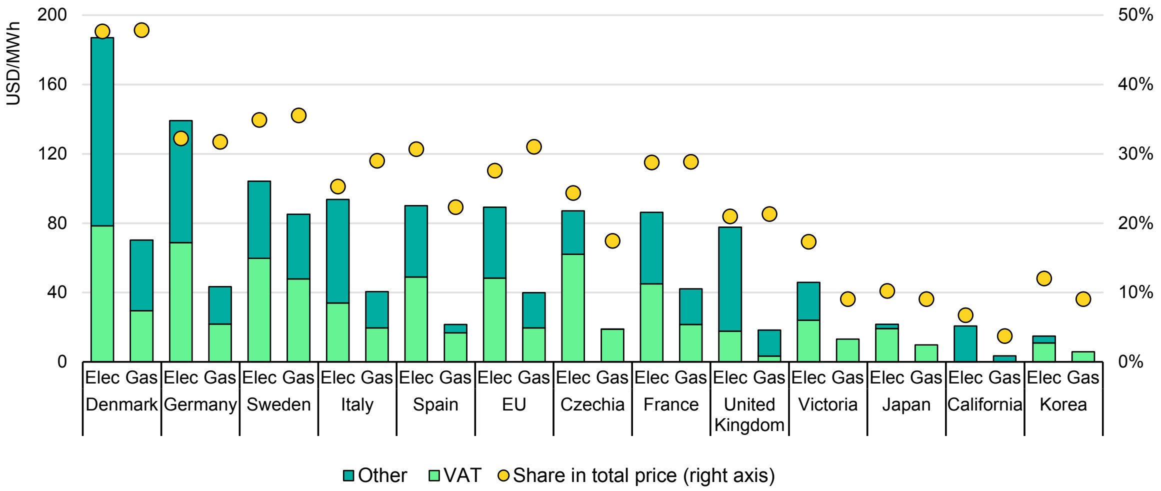
Notes: Share of electricity in total household expenditure is calculated as the total consumption of electricity by households times the nominal price, divided by total final consumption expenditure by households in a country.
Source: IEA analysis based on data from IEA Energy Prices (2025).

Heavier taxation of electricity hinders the shift from gas in households, dampening the pace of electrification

Taxes, fees, levies and charges are applied to electricity prices for households across regions, making up a significant proportion of the bills paid by consumers. In the first half of 2025, this component accounted for just under EUR 80/MWh or 28% of the average electricity price for EU households, and surpassed 30% in countries such as Denmark, Sweden, Germany and Spain. During this period, in absolute value per MWh, the average tax component of residential electricity prices in the European Union was 2.2 times the tax component of the natural gas price, with particularly significant differences in Spain (4.2 times) and Germany (3.2 times). In Denmark and Germany, the tax component of electricity prices was more expensive than the total price of natural gas for households in H1 2025.

Because total electricity prices for households are generally higher than those of natural gas, variable taxes such as VAT translate into higher absolute amounts for electricity, despite similar VAT rates of around 15%. Beyond VAT, non-VAT taxes, fees, levies and charges on electricity bills remain nearly twice as high as those on gas bills across EU countries. In other OECD economies such as Japan and Korea, despite the tax component on electricity prices being 2.2 and 2.6 times, respectively, the ones on gas in total shares of the tax component of prices are at 9-12% – less than half the levels observed in the European Union, enabling further electrification in households.

Taxes, levies, fees and charges in residential electricity and gas prices by type, and share in total price in selected countries and regions, H1 2025

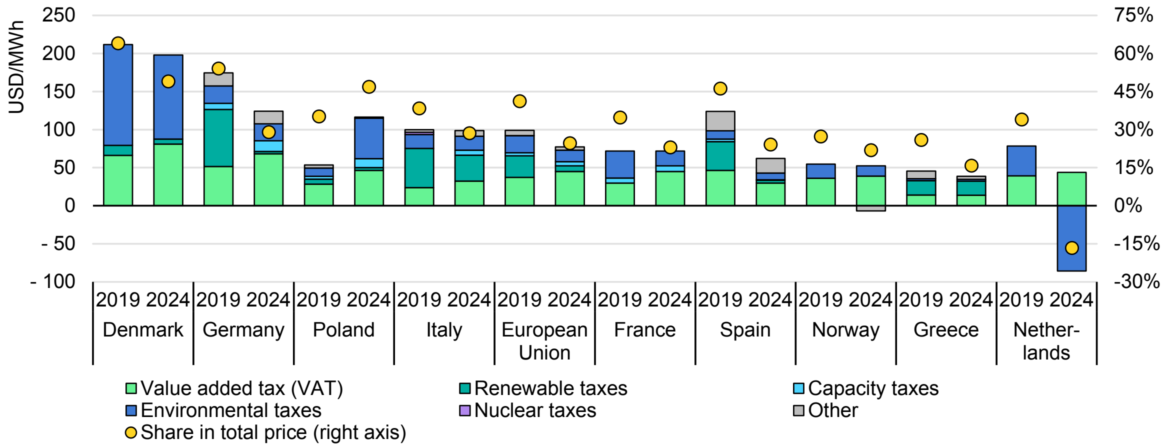


Note: Values for California include the 2025 Climate Credit.
Sources: IEA analysis based on data from Eurostat (2025), IEA Energy Prices (2025), Ofgem (2025), CPUC (2025).

Lowering taxation on electricity is one of the seven key actions identified by the European Commission to bring down electricity prices, and some countries are going in this direction to promote electrification and affordability for households. Denmark's 2026 finance bill includes a 99% reduction in the tax component of residential electricity prices for years 2026 and 2027, in a measure which will cost the state close to EUR 2 billion. In the United Kingdom, the budget approved in November 2025 includes a 75% decrease in the Renewables Obligation for households and a removal of the Energy Company Obligation, resulting in a yearly reduction in electricity expenditures of around GBP 150 per household. However, as governments move away from temporary relief measures introduced in 2021-2022, which in some cases involved VAT, other countries reinstated pre-crisis VAT rates in 2025. This was the case in Spain, which reinstated the 21% rate, up from a reduced 10%, and in France, which proposed the reinstatement of the full 20% rate, up from a reduced 5.5% applied to the fixed part of the bill. A general increase in the standard VAT rate in 2025 impacted electricity prices in other EU countries, such as Finland (25.5% up from 24%) and Estonia (24% up from 22%).

As noted in our Electricity 2025 report, given their high efficiency, heat pumps can reduce energy bills significantly for households in countries with comparable prices of electricity and natural gas, but can lead to higher bills in countries where electricity prices are more than three times the prices of gas.

Taxes, fees, levies and charges in residential electricity prices by type, and share in total price in selected countries and regions, 2024 vs. 2019



Source: IEA analysis based on data from Eurostat (2025). Negative values reflect government interventions such as subsidies, tax reductions and rebates to shield households from surging electricity prices, demonstrating strong support measures.

Reliability

Largescale outages amid system instability, equipment failures and weather impacts

As the Age of Electricity evolves, with steadily rising electrification rates and electricity demand, blackouts can impact a vast part of economies and social life. Outages induced by operational failures, technical error, or climate-driven events illustrate the importance of redundancy, resilience, and thorough oversight. The following list of outage incidents in 2025 underscores how ensuring the security, reliability and resilience of power systems is evolving from a technical challenge to a strategic necessity that requires unwavering attention from system operators, regulators, and policy leaders.

Voltage management increasingly important for power system stability

On 28 April 2025 at about 12:33 local time, the **Iberian Peninsula** suffered a widespread blackout, the largest European outage since the 2003 Italian Peninsula blackout. According to the initial report by ENTSO-E, and the analysis conducted by the Spanish system operator Red Eléctrica and the national authorities within the Committee established by the Spanish Government, the incident was of multifactorial origin, caused by a combination of high voltage volatility, limited reactive absorption at that moment, strong power oscillations, and rapid disconnections leading to a further surge in voltage. In the half hour prior to the incident, two distinct modes of oscillation occurred in the Continental Europe Synchronous Area (CESA). The respective system operators enacted a series of standard mitigating measures, including reduction in export flows from Spain to France and Portugal, and reconfiguration of internal power lines. While these measures had the desired effect of dampening oscillation, they also increased voltage in the Iberian power system and scaled down reactive absorption. Disconnection of generators prompted the voltage level in several nodes to further spike beyond the 435 kV operational limit.

The over-voltage set off a chain reaction of generation losses and a decline in the Spanish and Portuguese power system frequency. The Iberian Peninsula was completely desynchronised from the Continental European power system and cascading disconnections swept across the region, affecting Spain, Portugal, and a small border region of France. System collapse happened in a matter of seconds, bringing the Iberian Peninsula to a powerful voltage blackout.

Leveraging cross-border interconnections with France and Morocco while domestic black-start units came online significantly accelerated the restoration process in Spain, demonstrating the benefits of regional interconnectivity. The rapid restoration – completed within 12-16 hours – reflects the effectiveness of established restoration procedures and cross-border co-ordination, underscoring the importance of the EU's electricity interconnection objectives.

Another significant power outage associated with voltage instability took place in **North Macedonia**. In the early morning of 18 May 2025, a grid failure led to a partial blackout. Several power transformers tripped due to overvoltage, which weakened the system and led to the eventual separation of the country's transmission networks. Nearly 79% of the total system load was lost as a result of this disruption. Although the wider Continental European power system remained unaffected, the Bulgarian control area enacted an alert state for eight hours on account of high voltages on the same day. The country's transmission system operator, MEPSO, identified low electricity consumption and cross-border transit as the probable cause of high voltage levels on the grid.

Major power supply disruptions were triggered by equipment failures

On 25 February 2025 at about 15:16 local time, **Chile** was hit by its worst blackout in 15 years. A failure in the protection system caused the main north-south transmission line to shut down unexpectedly. This sudden dual-circuit outage spread with subsequent disconnections, leading to a system separation between the northern and southern parts of Chile. The North Zone, which was exporting power before the incident and where 30% of the national demand is located, lost electricity supply due to voltage instability. South-Central Chile, which had been importing power from the north and serves the remaining 70% of demand, collapsed within seconds of the failure, losing 1 800 MW of supply as contingency defence schemes malfunctioned. This incident plunged 14 of Chile's 16 regions, accounting for about 98% of the population, into darkness and incurred an estimated USD 450 million in economic losses. Around half of the country regained access to electricity later that night, and the system returned to normal around 9 AM the following day.

On 21 March 2025, **London's Heathrow Airport**, one of the busiest travel hubs in the world, was submerged in darkness and had to close operations for an entire day. More than 300 000 passengers and 1 350 flights were affected by the incident. According to the final report published by National Energy System Operator (NESO), one transformer in an adjacent electrical substation had caught fire, most likely caused by moisture ingress in the insulation around wires. While the airport had three power supply routes, the system was unable to ensure supply continuity following the single transformer failure, leaving the facility without power. Another incident caused by a substation fire occurred on 14 October in southern **Brazil**, which resulted in 10 000 MW of lost load, with more than 1 million customers affected.

Cuba suffered from two major outages in 2025, adding to the series of three nationwide blackouts in the second half of 2024. On 14 March, a substation breakdown near the country's capital propagated into an island-wide blackout, affecting around 10 million inhabitants. The second mass outage struck the island again six months later, on 10 September, which was related to a thermoelectric plant malfunction according to its Ministry of Energy and Mines.

On 2 May 2025, Bali, **Indonesia**, also experienced an expansive power outage that interrupted operations at the island's airport and other public infrastructure. Around 80% of the province and more than 940 000 residents suffered from loss of electricity supply. Indonesia's state utility, Perusahaan Listrik Negara (PLN), attributed the blackout to a disruption in the subsea cables connecting Bali's grid to the electricity system on Java Island.

A mass blackout that hit the eastern and northern parts of the **Czech Republic** on 4 July was initiated by the fall of a phase conductor, according to the Czech transmission system operator (ČEPS). Several transmission lines automatically disconnected, and a power plant was knocked out, rendering parts of the electricity network to perform in an island mode that later became inoperable. This event affected roughly 1 500 MW of generation and 2 700 MW of consumption.

On 26 September, more than 2 million customers in three states of the Yucatán Peninsula, **Mexico**, also suffered a widespread power outage. It was later announced maintenance work on high-voltage lines had triggered the incident, switching off nine power plants and 16 generation units, totalling approximately 2 200 MW of electricity supply.

Outages due to attacks on infrastructure are also becoming a challenge, with the situation in Ukraine covered in detail in the Regional Focus section of our report.

Extreme weather events continued to cause major power outages in 2025

In the **United States**, major weather-related power outages started at the onset of the New Year. Seven states were hit by widespread power outages on 6 January 2025 as Winter Storm Blair left more than 300 000 people without heat or electricity. A state of emergency was declared and authorities warned citizens to steer clear of downed wires and damaged equipment. Meanwhile, in Los Angeles, starting from 7 January, a powerful windstorm and massive fires left more than 200 000 households and businesses without electricity. Powerful windstorms, thunderstorms, blizzards and tornadoes swept the country again in March, causing outages in more than 20 states, affecting 500 000 homes and businesses. On 29 April, severe wind swept across Pennsylvania, toppling trees and crippling utility poles, resulting in power outages that impacted over 450 000 consumers. About a month later, on 26 May, a combination of heavy rain, hail, and strong winds caused extensive damage to electrical equipment and cut power to more than 130 000 customers in Texas.

Across the Atlantic, **Ireland** was also hit by record-breaking wind gusts of Storm Éowyn in January, which brought about unprecedented and immense damage to electricity infrastructure. Over 768 000 customers were affected and 39 000 people in remote and rural communities remained without power for a week after restoration efforts began. ESB Networks, Ireland's distribution system operator, announced 3 000 electricity poles across the country needed replacement and approximately 900 km of new conductor cable was to be installed after the event.

In **Australia**, as Cyclone Alfred swept across South East Queensland and northern New South Wales in March 2025, more than 500 000 customers lost power. Fallen trees and tree branches had to be lifted off power lines, which led to protracted restoration efforts and left many without electricity for multiple days. South East Queensland and the Victoria region suffered from power outages again on the morning of 27 October, as high wind gusts and large hailstones swept through the area. Around 26 000 households in Queensland and 1 300 customers in Victoria woke up in the dark as the extreme weather caused significant damage to the power network.

On 22 September, Super Typhoon Ragasa made landfall in the **Philippines** with torrential downpours and raging winds. This coincided with the ongoing monsoon season in the region, exacerbating flooding and causing landslides. The tropical cyclone later made its way toward **China**. The typhoon significantly damaged key infrastructure, including transmission facilities and distribution utilities, triggering large scale outages. Hospitals, water facilities, and telecommunication stations had to resort to emergency generators to maintain essential services. Approximately 750 000 households in the Philippines and 56 000 in China were affected by the blackouts. The National Electrification Administration (NEA) of the Philippines later announced that electric co-operatives in the typhoon-hit region incurred substantial infrastructure damages.

On 28 October, Hurricane Melissa made landfall in **Jamaica** as a Category 5 storm, causing widespread outages that left more than 530 000 people without electricity. Power restoration efforts were delayed by damaged infrastructure such as impassible roads, which is a common challenge in the aftermath of extreme weather events, further burdening these affected communities. Despite the government's prioritisation and co-ordination of recovery efforts, some outages persisted for more than three weeks after the hurricane.

Meanwhile, unusually high temperatures of nearly 50 ºC in **Iraq** led to shutdown of two transmission lines, which resulted in a nationwide blackout on 11 August 2025. According to the Iraqi Ministry of Electricity, the shutdown triggered "a sudden loss of more than 6 000 MW on the grid", which forced power plants offline and the grid to eventually collapse under the pressure. This incident demonstrates the conundrum of maintaining stable system operations under the dual pressures of rising temperatures and surging consumer demand.

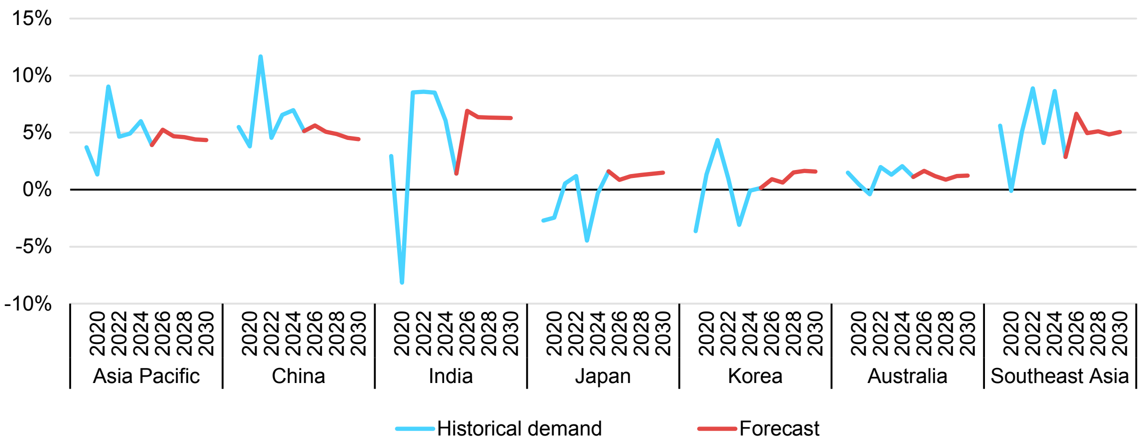
Regional Focus

Asia Pacific

Electricity demand set to increase strongly after mild weather tempered growth in 2025

Electricity demand in the Asia Pacific region increased by 4.1% y-o-y in 2025, easing from the 6% pace in 2024. Milder weather conditions in 2025, compared to the previous year, moderated growth in many parts of the region, especially in India and Southeast Asia. Nevertheless, two-thirds of the global demand increase came from Asia Pacific. Over the 2026-2030 five-year forecast period, we expect the region to record robust gains of an average 4.7% annually. China will account for almost 70% of the region's additional demand, but India (15%) and Southeast Asia (11%) also will be significant contributors. Japan and Korea are forecast to see a resurgence in demand growth. By 2030, 56% of world's electricity use will be in Asia Pacific, up from 53% in 2025.

Year-on-year percent change in electricity demand, Asia Pacific, 2019-2030

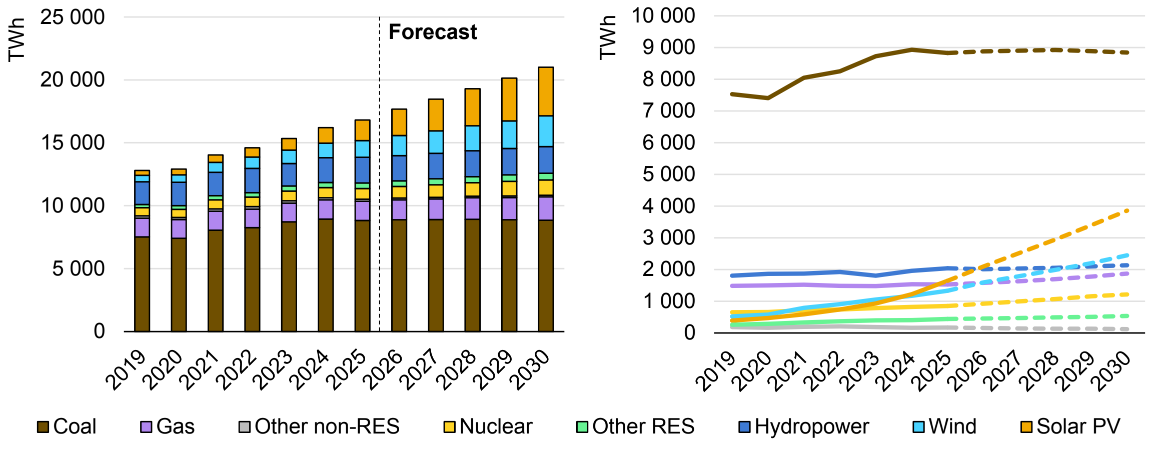


IEA. CC BY 4.0.

Notes: Data for 2026-2030 are forecast values. The plots start from 2019, whereas the x-axis labels are shown only for the even years due to limited space.

Solar PV and wind are the fastest growing sources of electricity generation across the Asia Pacific, together meeting 86% of the additional demand over the outlook period, with nuclear and natural gas supplying most of the rest. By 2027, solar PV will become the largest renewable source of electricity in the region, surpassing hydropower. Coal will remain the dominant single source of electricity generation, though its role in the power mix is evolving. New coal capacity is still being commissioned in Asian markets, notably in China and India. However, the rising share of renewables in the system result in coal-fired power plants increasingly providing system flexibility and backup for variable renewable energy (VRE), limiting their capacity utilisation. Natural gas-fired output is forecast to see an acceleration in growth over the outlook period, driven by lower LNG price assumptions. Southeast Asia is expected to be a major catalyst, accounting for a substantial 44% of gas-fired generation growth in Asia Pacific.

Electricity generation by source in Asia Pacific, 2019-2030



Notes: RES = renewable energy sources. 'Other non-RES' includes oil, waste and other non-renewable sources. 'Other RES' includes geothermal, bioenergy, concentrated solar power (CSP), and ocean energy. Data for 2026-2030 are forecast values.

China

China is expected to provide around half of the global growth in electricity demand through 2030

Electricity demand in China rose by 5.1% in 2025, slightly slower than the 7% increase recorded in 2024. Demand is forecast to rise at an average annual 4.9% from 2026 to 2030, a moderation from the 6% average of the past decade. While ongoing economic restructuring continues, demand growth will be driven by sustained electrification, expanding manufacturing and the services sector.

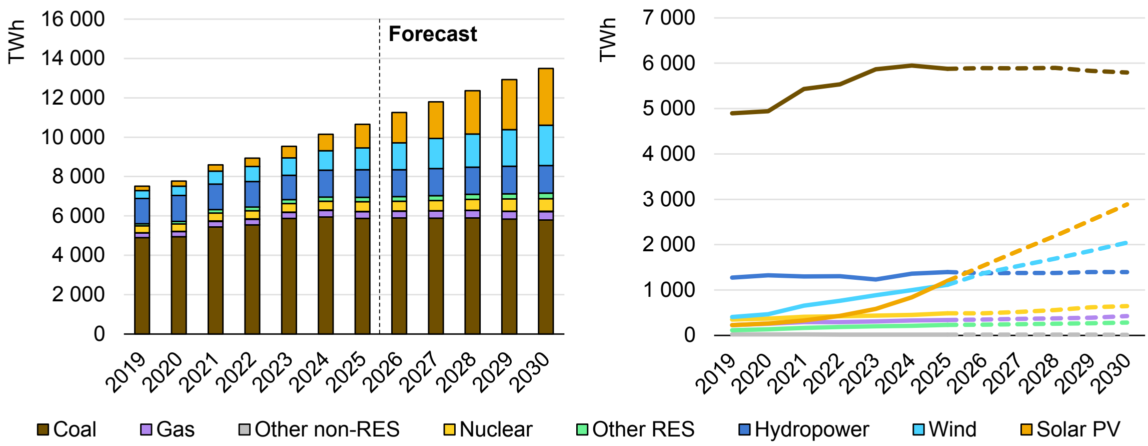
Warmer winter temperatures reduced heating needs in early 2025, but record-breaking summer heatwave in July drove peak electricity demand. Surging temperatures in the southern provinces further boosted electricity demand in October. At the same time, efficiency gains, including consumer appliance upgrades and government targets to reduce energy consumption per unit of GDP by 3%, are also other relevant developments contributing to demand trends.

In 2025, solar PV generation surged by 43% and wind by 12%, with the share of VRE in overall electricity generation reaching 22%, up from 18% the previous year. The steep increase was underpinned by record capacity additions. Between

January and December, 316 GW (AC) of solar and 119 GW of wind were added, with more than a quarter of this capacity commissioned in May alone. The surge in renewable capacity additions in early 2025 was mainly triggered by producers accelerating project commissioning ahead of the June 2025 deadline ending fixed-price remuneration in line with the implementation of market-based pricing reforms. These changes replaced fixed tariffs with competitive auctions awarding Contract for Differences (CfDs), which are expected to narrow profit margins for developers. While capacity additions increased, grid integration challenges remain significant. In the first eleven months of 2025, the solar curtailment rate reportedly rose to 5.2% from 3% over the same period in 2024, while wind curtailment climbed to 5.7% from 3.7%.

Coal-fired generation in China declined by an estimated 1.2% in 2025, reversing a modest rise in 2024. This shift highlights coal's evolving role in the power system, which is increasingly used to provide flexibility and backup for intermittent renewable sources. While coal remains the largest source of electricity generation in absolute terms, its share of overall generation will gradually be eroded by rapid growth in renewables, falling from 55% in 2025 to 43% in 2030. Nonetheless, coal power capacity continues to expand, with 21 GW commissioned in the first half of 2025 and 46 GW of projects starting or restarting construction. This reflects a delayed response to the permitting boom of 2022-2023. Previously approved coal projects are expected to continue driving high commissioning levels through 2027. Only 1 GW of coal-fired capacity was retired in the first half of 2025, with just 16 GW retired since 2021. Despite new coal power plants coming online, rising renewables are expected to increasingly push coal units into flexibility and backup roles, reducing their capacity utilisation.

Electricity generation by source in China, 2019-2030



IEA. CC BY 4.0.

Notes: RES = renewable energy sources. 'Other non-RES' includes oil, waste and other non-renewable sources. 'Other RES' includes geothermal, bioenergy, concentrated solar power (CSP), and ocean energy. Data for 2026-2030 are forecast values.

In 2025, nuclear generation rose by 7.7% y-o-y, supported by new capacity additions. Hydropower output increased by 2.8% y-o-y due to more favourable hydrological conditions in the second half of the year, compared to a weak H1 2025. Gas-fired generation, which accounted for a small 3% of the electricity mix in 2025, saw an estimated growth of around 2%, a slowdown from 7.5% in 2024. This was mainly due to the reduced competitiveness of gas versus renewables and coal.

China's electricity generation mix will shift further towards low-carbon sources in the outlook period. Solar PV and wind are forecast to continue expanding at a brisk pace. Solar generation is expected to rise at an average annual rate of over 19% through 2030, while wind stabilises at around 13% per year. Over the same period, nuclear generation is projected to grow at close to 6% annually, supported by the commissioning of new reactors. In a marked reversal of trend, coal-fired output is expected to plateau and decline only slowly, by an average of less than 0.5% per year in the forecast, compared to growth of 3.9% in the 2018-2024 period, as low-emissions sources gain further ground. At the same time, pumped hydro storage, alongside expanding battery storage, will play a growing role in balancing variable renewables.

Battery storage emerges as a central pillar in China's electricity system transformation

Battery storage is playing an increasingly important role in China's power system transformation. Preliminary data indicates that China has installed 66 GW/189 GWh of additional new energy storage[1] capacity in 2025, more than 50% and an above 70% year-on-year increase in storage capacity and volume, respectively.

In September 2025, China's National Development and Reform Commission (NDRC) and the National Energy Administration (NEA) issued a three-year action plan aiming to boost new-type energy storage solutions, which includes scaling up storage applications in power generation and accelerating technological innovation designed to ensure the stability of the grid and integrate renewables. The plan is targeting over 180 GW of installed capacity by 2027, up from 74 GW in 2024. Recent regulatory changes removing the energy storage pairing obligation for new wind and solar projects imply that new installations will be mainly driven by market signals.

Coal-fired power plants are also undergoing a transformation to support system flexibility. In April 2025, the government released an implementation plan setting

[1] China's definition of "new energy storage" includes electrochemical, compressed air, flywheel and supercapacitor energy storage systems, excluding pumped hydro storage.

technical requirements for minimum output levels to allow for deep peak shaving, and load ramping capabilities for coal-fired power plants in 2025-2027. The plan also states that new coal plants should have 10-20% lower CO_2 emissions per unit of electrical energy generated than the 2024 fleet.

China continued advancing electricity market reforms and policies aimed at effective integration of renewables

China submitted its 2035 Nationally Determined Contribution (NDC) in November 2025, aiming to reduce economy-wide greenhouse gas emissions by 7-10% from their peak by 2035. While no base year has been specified, this is the first absolute emission-reduction target set for China. The newly submitted NDC also includes a target to increase the share of non-fossil fuels in total energy consumption to over 30%. These announcements are in addition to plans already in place such as peaking whole-of-economy emissions before 2030 and phasing down coal consumption between 2026-2030.

Electricity market reforms are also advancing in China. The NDRC and NEA released the Notice on Comprehensively Accelerating the Construction of the Electricity Spot Market in April 2025, requiring full coverage of provincial spot markets by the end of 2025. Currently, seven spot markets are operational, with pilot programmes at different stages of implementation in 22 other provinces. For provinces where renewables account for more than 40% of the electricity mix, the NDRC and NEA have allowed a reduction in the requirement for wholesale buyers to contract 80% of their demand through medium- and long-term contracts, lowering it to 60%. This adjustment provides greater scope for spot market procurement and continues to adapt the market framework to growing renewable penetration.

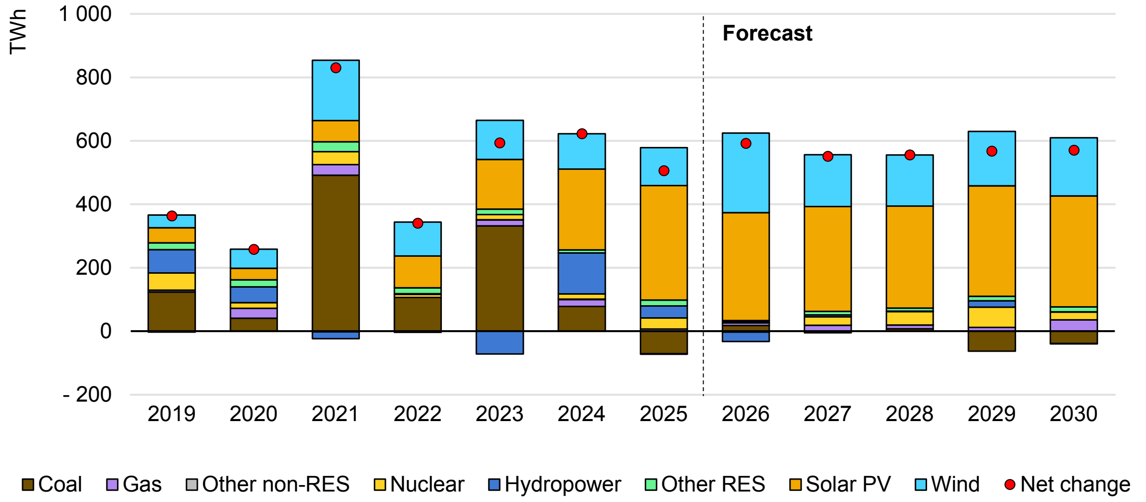
The latest set of basic rules governing China's power markets was released in 2025. This included new rules for the Electricity Ancillary Services Market and for Power Market Metering and Settlement, as well as updated rules for medium- and long-term electricity trading. According to the Chinese authorities, the "1+6" policy framework for the national unified power market is now complete, with the "1" referring to the overarching rules on power market operation and the "6" to the supporting sets of specific rules.

Network tariffs revisions were released by NRDC in November 2025, clarifying the regulatory frameworks for provincial, regional and inter-provincial transmission tariffs. These provisions notably introduce a two-part tariff for the use of the inter-provincial network comprising of a capacity and energy part, moving away from energy-based tariffs. The aspect of energy-based tariff structures limiting efficiency for incentivising inter-provincial transactions had been previously covered by the IEA.

Alongside market reforms, China introduced several policy documents likely to have a direct impact on electricity demand, particularly in sectors such as industry, heating and transport. Mandatory Renewable Energy Quotas for Industry were expanded to include additional industrial sectors in July 2025. These quotas now require energy-intensive industries such as steel, cement, polysilicon, and certain data centres to source a defined share of their electricity from renewables. These requirements had been previously introduced for aluminium, provinces and electricity distribution companies, but have now been strengthened as part of the new rules. In March 2025, China released its first-ever National Action Plan on Heat Pump Development, signalling its strong commitment to their deployment across sectors, as well as a three-year action plan for doubling electric vehicles charging capacity by 2027.

Chinese authorities released Management Measures for Distributed Photovoltaic in January 2025. This new policy, analysed in more detail in the IEA's Integrating Distributed Energy Resources in China report launched in late 2025, shifted the focus of distributed solar PV policy support towards small-scale solar PV installations connected to lower-voltage networks, terminating the eligibility of commercial and industrial consumers to this type of support.

Year-on-year change in electricity generation in China, 2019-2030



Notes: RES = renewable energy sources. 'Other non-RES' includes oil, waste and other non-renewable sources. 'Other RES' includes geothermal, bioenergy, concentrated solar power (CSP), and ocean energy. Data for 2026-2030 are forecast values.

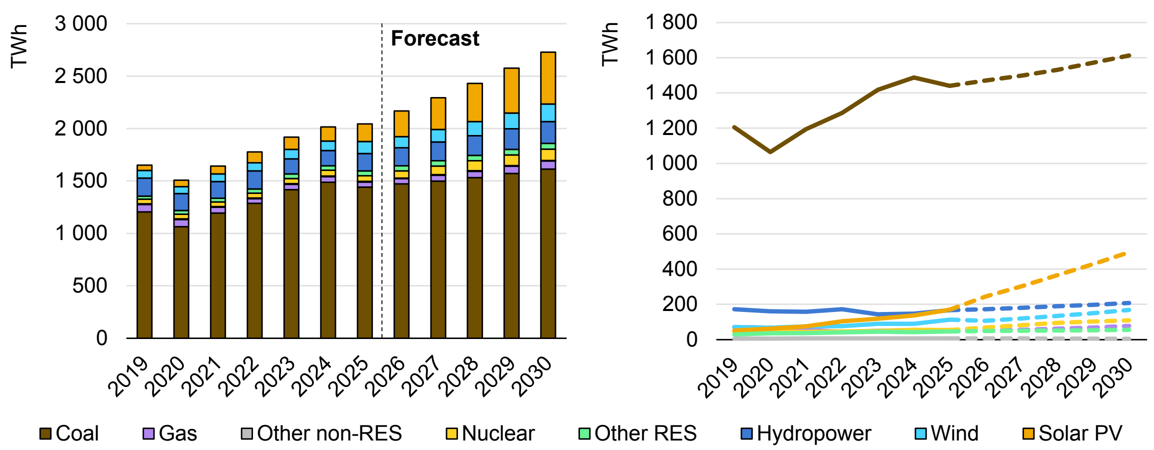
India

Demand growth slowed amid weather effects, but is set to remain strong through 2030

In 2025, electricity demand in India grew by 1.4% y-o-y, marking the weakest growth rate since at least 1972, excluding the decline seen in 2020 during the pandemic. The muted growth was largely driven by milder weather conditions, with fewer heatwaves in the summer and an early onset of the monsoon season, which eased cooling needs and reduced peak loads during the hottest months. Slower industrial activity also contributed to the moderation in demand growth.

In our five-year outlook, which assumes normal weather patterns, electricity demand is expected to rebound by a sharp 6.9% in 2026, in line with economic activity, and continue rising steadily through 2030 at an average annual rate of 6.4%. Growth will be supported by expanding cooling needs due to rising income levels among the population, increasing industrial output, and escalating power consumption in agriculture and transport, among other sectors.

Electricity generation by source in India, 2019-2030



Notes: RES = renewable energy sources. 'Other non-RES' includes oil, waste and other non-renewable energy sources. 'Other RES' includes geothermal, bioenergy, concentrated solar power (CSP) and ocean energy. Data for 2026-2030 are forecast values.

Renewables break new records amid strong policy support and ever-cheaper solar PV

Renewable electricity generation grew by 20% in 2025, the strongest annual increase in the last decade. Solar PV generation led the growth, up by 24% in 2025, a sharp rise from 15% in 2024, which was boosted by substantial cost declines. Solar PV is projected to maintain strong momentum over the forecast period, with annual growth forecast to average 24%, adding more than 300 TWh. Wind also saw robust gains of close to 28% in 2025 and is forecast to grow at a steady average annual rate of over 8% through 2030. Hydropower rose by 14% y-o-y in 2025, up from 2.5% in 2024, due to improved hydrological conditions.

India has already achieved 50% of its installed capacity from non-fossil fuel sources ahead of its 2030 target under the Paris Agreement. Between 2026 and 2030, the country is expected to add almost 300 GW of renewable power capacity. Domestic solar PV module manufacturing capacity reached 100 GW under the Approved List of Models and Manufacturers (ALMM), reflecting the country's goal of a self-reliant clean energy supply chain. National schemes continue to support solar PV deployment, with programmes such as PM-KUSUM, which incentivises the shift to solar in meeting agricultural electricity demand, and the PM-Surya Ghar: Muft Bijli Yojana initiative aimed at promoting rooftop solar installations using subsidies.

In 2025, India's Ministry of New and Renewable Energy announced its first National Policy on Geothermal Energy to promote exploration and development of geothermal resources.

Following years of rapid renewable capacity growth, India's power sector is now shifting its focus to system integration and long-term reliability. In October 2025, the Ministry of New and Renewable Energy announced its new priorities, signalling the need to align renewable expansion with grid strength, financial discipline, and advancing long-term market design to support the country's 500 GW non-fossil capacity target in a resilient and cost-effective manner. The Central Electricity Authority issued guidelines in July 2025 requiring Automatic Weather Stations at large solar and wind projects to ensure real-time weather tracking. This is a step towards ensuring reliable and accurate renewable generation forecasting and grid reliability.

The Ministry of Power is also prioritising digitalisation as a key part of system reliability. In September 2025, it established the taskforce India Energy Stack (IES) to develop a digital public infrastructure (DPI) for the power sector. The task force aims to create a connected and interoperable energy ecosystem through the development of a Utility Intelligence Platform in collaboration with selected power distribution companies. Built on standardised open APIs and protocols, this platform will integrate data from across IT systems, enhancing innovation, operational efficiency, and informed decision-making.

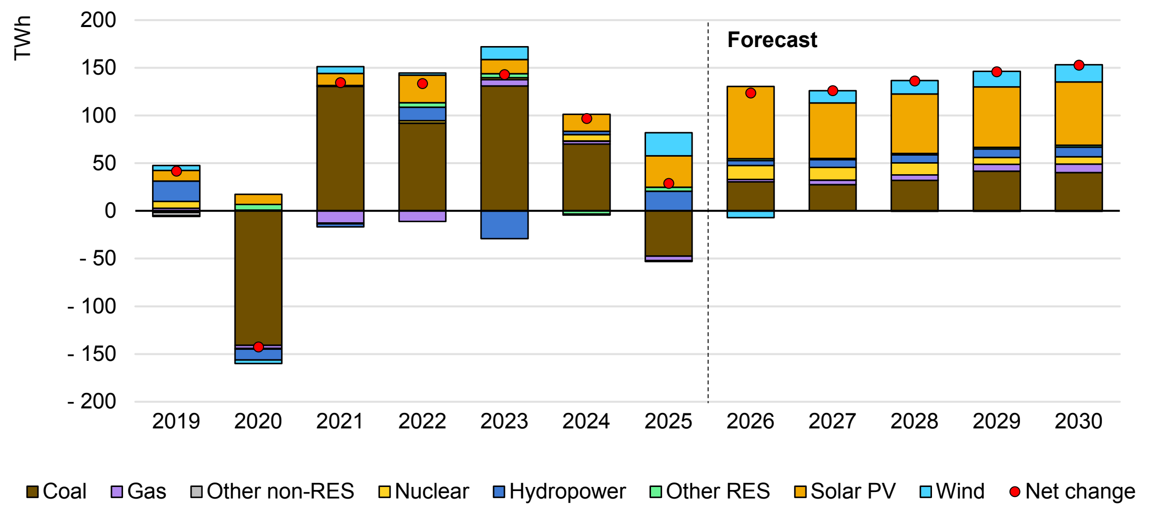
Other power sector reforms involve the continued roll-out of the Revamped Distribution Sector Scheme to improve financial sustainability and service reliability, including sanctioning of 203 million smart meters. The government also introduced financial incentives in the form of extra borrowing space linked to state-level power sector reforms to enhance efficiency and performance.

India targets nuclear expansion while coal remains central to power supply

India is looking to nuclear power as a key part of its energy security and decarbonisation strategy with the newly announced Nuclear Energy Mission, which includes a target of 100 GW of nuclear capacity by 2047. This plan aims to enhance domestic nuclear capabilities through increased private sector participation as well as accelerate the development and deployment of advanced nuclear technologies such as small modular reactors (SMRs). This was reinforced through the approval of a landmark piece of legislation in December 2025, the SHANTI bill, which modernises governance and enables private participation in the nuclear industry, a restriction which had previously limited investment, industrial participation and project momentum.

India's largest power generator, National Thermal Power Corporation (NTPC), is entering the nuclear sector through its new subsidiary NTPC Parmanu Urja Nigam Limited (NPUNL). India has also approved the creation of a joint venture between the government-owned Nuclear Power Corporation of India Limited (NPCIL), the country's sole operator of nuclear power plants, and NTPC to construct, own and operate nuclear power plants in the country. Nuclear generation is expected to grow steadily over the 2026-2030 period, at an average annual rate of 12%.

Year-on-year change in electricity generation in India, 2019-2030



Notes: RES = renewable energy sources. 'Other non-RES' includes oil, waste and other non-renewable sources. 'Other RES' includes geothermal, bioenergy, concentrated solar power (CSP) and ocean energy. Data for 2026-2030 are forecast values.

In 2025, coal-fired generation fell by 3.2%, following a 5% rise in 2024. However, this weather-related decline is expected to be temporary, with demand growth forecast to increase rapidly through 2030, facilitating higher coal burn in the power sector, with a large pipeline of projects already under construction. Between 2026 and 2030, coal-fired generation is forecast to grow at an average annual rate of 2.3%, maintaining its role as the main source of electricity, with a share of around 60% in 2030. State-level distributors continue to sign long-term contracts with coal power generators, supporting this trend. Gas-fired generation declined by 9% in 2025 but is expected to pick up over the forecast period, with an average growth rate of close to 10% during 2026-2030, supported by lower LNG price assumptions as global LNG supply rapidly expands. Total CO_2 emissions from electricity generation fell by more than 3% y-oy in 2025, the first decline since 2020.

Japan

Electricity demand growth posts a resurgence in 2025, marking a sharp reversal of the declining trend over the past decade

Electricity demand in Japan is estimated to have risen by around 1.6% year-on-year in 2025, based on data for the first 11 months[2]. This increase was driven by temperature-related increases in consumption, expanding data centres and ongoing electrification.

From 2026-2030, Japan's electricity demand growth is expected to increase steadily, from around 1% in 2026 and to reach 1.5% by 2030, for an average annual rate of around 1.2%. This is a significant step change in the demand trend, reversing the downward trajectory of the past decade. While residential electricity demand is expected to decline by 0.6% per year due to ongoing energy efficiency improvements, commercial and industrial use is projected to grow by 1.8% due to continued expansion of data centres, new builds of semiconductor factories coming online and expanding electrification.

Increasing nuclear energy supply to meet electricity mix goals

The 7th Strategic Energy Plan, approved by the Japanese Cabinet in February 2025, outlines the basic direction for Japan's energy policies. In tandem, the Outlook for Energy Supply and Demand in FY2040 was published, detailing the country's plan to increase the share of renewable energy to approximately 40-50% in 2040, which is around two times the 2023 level, and to raise the share of nuclear power to approximately 20% by 2040, which is two-and-a-half times the 2023 share.

Nuclear power generation rose by about 11% in 2025 and, assuming restarts proceed as planned, with growth forecast at an average annual rate of 14% over the 2026-2030 period. Potential delays in restarts could affect this rate. Following the Fukushima Daiichi accident in 2011, the country's fleet of nuclear plants were

[2] Data is from the Organization for Cross-regional Coordination of Transmission Operators (OCCTO).

suspended from operations and among the 33 operable reactors, 14 have now resumed operations after meeting new safety standards.

Tokyo Electric Power Company (TEPCO) is working towards the restart of two units at Kashiwazaki-Kariwa, the country's largest nuclear power plant with seven units capable of producing about 8 000 MW. In the wake of the Fukushima Daiichi accident, Unit 6 (1 356 MW) and Unit 7 (1 356 MW) were closed in August 2011 and March 2012, respectively. Operator TEPCO has already completed the technical preparations for the restart of Unit 6. Unit 7 has cleared regulatory safety screening, however regulations also require the construction of an anti-terrorism back-up facility within a certain period of time. Unit 7 exceeded that deadline in October 2025 so its restart is being postponed. As such, only Unit 6 is expected to be available for restart in the near term, subject to final approvals. In November, the governor of the Niigata Prefecture, where the plant is located, agreed to the restart and this decision was subsequently backed by the Niigata Prefectural Assembly in December. The Nuclear Regulation Authority approved the start-up of Unit 6 on 21 January 2026, with commercial operation targeted for late February.

Further nuclear restarts are also in progress. Hokkaido Electric Power Company's Tomari Unit 3 (866 MW) has cleared regulatory screening and received approval for safety-related design changes, including enhanced tsunami protection and strengthened seismic performance. Construction of coastal fortification structures is underway, targeting operation in 2027. Safety reinforcement measures are being implemented at Japan Atomic Power Company's Tokai Unit 2 (1 060 MW) to meet strengthened criteria, with completion expected by 2026 and restart expected soon thereafter, subject to regulatory approval.

Renewables on track for steady growth as Japan invests in grid flexibility and innovation

Japan's renewable power generation is estimated to have increased by around 5% y-o-y in 2025, based on data for the first 11 months, as output from solar PV and wind power generation both rose about 13%. Meanwhile fossil-fired thermal generation declined by 1.7%, also supported by improved performance of the coal power fleet.

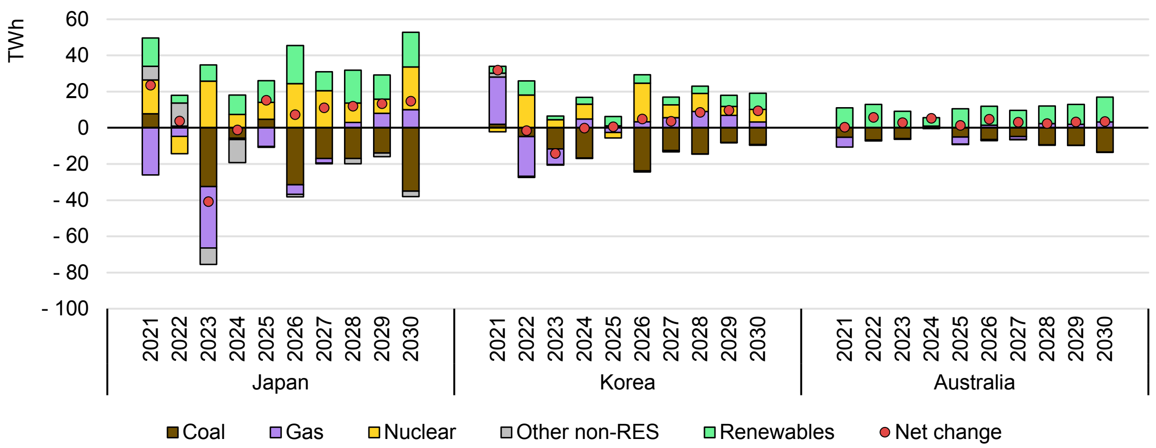
Renewable energy is expected to grow at an average annual rate of around 6% in 2026-2030. However, challenges remain in scaling up renewables, particularly due to the intermittency of VRE power output. In response, Japan is investing in the development of its power grid to integrate higher shares of renewables.

Japan has implemented a Long-Term Decarbonised Power Source Auction to promote investment in low-carbon power and flexibility resources, including renewables, hydrogen, ammonia co-firing, and nuclear power.

Efforts are also underway to accelerate the deployment of next-generation technologies such as perovskite solar cells, offshore wind power generation and advanced geothermal power generation. The Ministry of Economy, Trade and Industry (METI) has been supporting these initiatives mainly through the Green Innovation Fund, which will allocate a total of approximately JPY 2.8 trillion (Japanese yen), or around USD 18 billion, to continuously support R&D, demonstration and implementation of innovative decarbonisation technologies, including renewable energy.

One notable event occurred in August 2025, when Mitsubishi Corporation, the selected developer for an offshore wind power project, announced its withdrawal after determining that a viable business plan was no longer feasible due to rising construction costs and worsening profitability. In response, the government announced reforms to the offshore wind bidding process, including measures to better reflect rising construction costs and strengthen assessments of project. The government continued to implement reforms to advance offshore wind policy by passing the "EEZ Law" on 3 June 2025, which amended the Marine Renewable Energy Law to allow offshore wind farms in its the exclusive economic zone. In addition, the country approved a strategy to build a pipeline of at least 15 GW of floating offshore wind capacity by 2040.

Year-on-year change in electricity generation in Japan, Korea, and Australia, 2021-2030



Notes: RES = renewable energy sources. 'Other non-RES' includes oil, waste and other non-renewable sources. 'Other RES' includes geothermal, bioenergy, concentrated solar power (CSP) and ocean energy. Data for 2026-2030 are forecast values.

Korea

Electricity demand is set to rise steadily, while low-emissions generation's share reaches 50% in 2030

Korea's electricity demand remained relatively flat in 2025, based on year-to-date data through November. However, demand is projected to grow from 2026 onward, at an average annual rate of 1.3% through 2030. The three major drivers of growth include the expansion of major semiconductor manufacturing clusters, the rapid development of AI data centres, and the increasing electrification across sectors.

Meanwhile, peak demand rose sharply in 2025, primarily due to the record-breaking heat waves. Marked as the hottest July on record, average peak demand for the month posted a 5.6% y-o-y rise. In August, the country reached its highest ever daily load at 104 GW. This new peak highlighted the importance of system adequacy amid increasingly frequent extreme weather events, as the reserve margin stood at 9.4% at that moment.

Low-emissions generation, including solar, wind and nuclear, is expected to reach 50% of the total generation mix by 2030. In 2025, nuclear power generation decreased slightly by around 1.5%, while solar PV and wind power output grew by 17% and 11%, respectively. The biggest privately-developed wind farm in Korea, the Jeonnam Offshore Wind Farm 1 with a total capacity of 96 MW, started commercial operation in May 2025. Coal-fired generation remained relatively flat in 2025 and is forecast to decline by an average of just over 8.5% each year to 2030. Last year marked the first year of major retirements of coal fleets, with 7.5 GW of closures expected by 2030. Gas-fired generation declined by around 1.5% y-o-y in 2025 but is expected to reverse trend and grow at an average annual rate of 3.2% over 2026-2030.

Battery-led grid flexibility and renewable-driven policy gain momentum

The Korea Power Exchange (KPX) launched the country's first nationwide auction for battery energy storage systems in 2025. Recognising its potential to support grid integration of VRE, the first-round auction tendered 540 MW (3 240 MWh) of six-hour duration storage and awarded 565 MW (3 390 MWh) of projects, mostly located in the southwestern regions with the highest VRE share in the country.

The Ministry of Climate, Energy and Environment (MCEE) was established to align Korea's policies under a cross-sectoral governance. In 2025, the government finalised the nation's 15-year energy outlook, the 11th Basic Electricity Supply and Demand Plan, which includes two new nuclear power plants, Shin-Hanul Units 3 and 4 at around 1.4 GW each, with a total 2.8 GW capacity, and one SMR of 0.7 GW, while adding an annual average of 8 GW of renewable capacity by 2030. The plan also sets a 2030 target of 4.2 GW of flexibility resources, primarily battery storage. Separately, the new ministry has signalled its intention to double down on power sector decarbonisation by setting a target of 100 GW for renewable capacity by 2030.

Australia

Electricity generation from renewables is expected to surpass coal over 2026-2030

Electricity demand in Australia rose by just over 1% in 2025 and is forecast to continue increasing by an average 1.2% y-o-y from 2026 to 2030. In the meantime, coal generation will remain on its declining trend, decreasing from 46% of the electricity mix in 2024 to 44% in 2025, and to 27% in 2030. Gas-fired generation fell by 8% y-o-y in 2025 but is expected to return to growth over 2026-2030, rising at an average of 3.1% annually.

Renewable energy sources supplied over 40% of electricity across Australia's two major grids, the National Electricity Market (NEM) and the South West Interconnected System (SWIS). Over the whole country, renewable generation is forecast to increase by an average of over 8.5% y-o-y to 2030. In 2025, renewable generation reached about 38% of total supply, consisting mainly of solar (19%), wind (13%), and hydropower (5%). These gains led to several peak renewable penetration records in 2025.

The Australian government has a target to reach 82% renewable electricity in the share of electricity consumption by 2030. Progress towards this goal has been supported by the Capacity Investment Scheme (CIS), a government revenue underwriting programme which was boosted in 2025 to provide support for 40 GW of additional capacity by 2030, specifically targeting renewable generation and clean dispatchable capacity.

Battery energy storage systems (BESS) are playing an increasing role in meeting power system flexibility needs. In Australia's NEM, there is over 4.3 GW of grid-scale batteries in operation, with another 12.6 GW in the development pipeline, equivalent to the NEM's existing gas capacity. The NEM’s market design arrangements, including its five-minute settlement and ten frequency control ancillary services (FCAS) markets provide strong incentives for fast-response technologies such as BESS to deliver flexibility, support frequency management and earn revenues across multiple services.

Distributed BESS are also playing an emerging role in balancing Australia’s significant rooftop solar capacity. More than one-third of households now have rooftop PV, contributing to steep intraday swings in net demand and new operational challenges. In South Australia, rooftop solar generation has at times exceeded underlying state demand, highlighting the importance of flexible resources and inter-region transmission capacity. To support these new resources, the government introduced the Cheaper Home Batteries Program, which provides a discount of around 30% on the upfront cost of installing small-scale battery systems where it is connected to a new or existing solar PV system. In the first six months since its launch in June 2025, the programme has delivered batteries to more than 155 000 households and small businesses, providing a total storage volume of 3.5 GWh. Additionally, the new EnergyConnect interconnector between South Australia and New South Wales will give operators flexibility to export surplus VRE generation. Construction of phase 1 was finished in 2025, and full operation is expected for late 2026.

Another initiative by the Australian government, effective in 2026, is the Solar Sharer, which will require retailers to offer free electricity to households for at least three hours in the middle of the day when solar generation is at its peak. These programmes are expected to help reduce consumer bills and provide power system flexibility benefits.

Southeast Asia

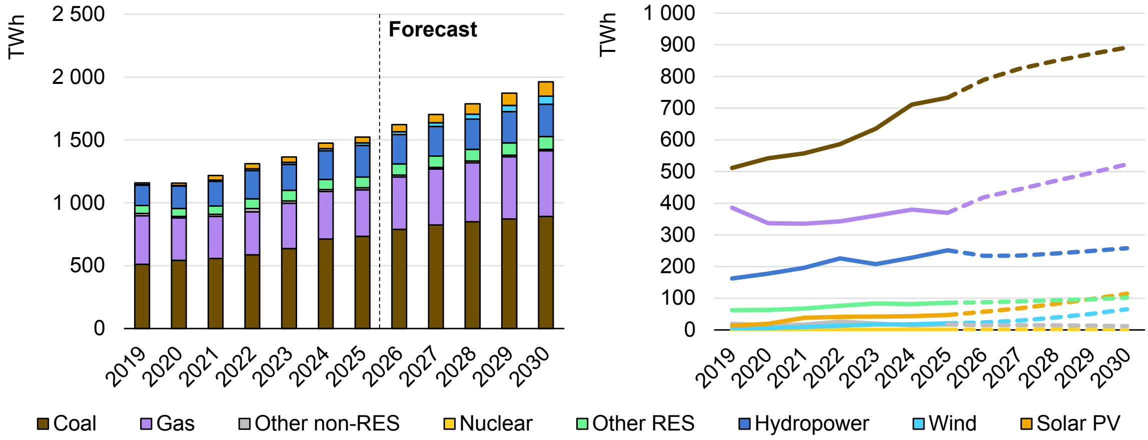
Demand growth was tempered by milder weather, but set to regain momentum and resume its robust pace out to 2030

Electricity demand in Southeast Asia grew by an estimated near 3% in 2025, easing from the sharp 8.6% surge in 2024, as milder weather and slower economic growth weighed on electricity consumption. Demand is expected to grow at an average annual rate of 5.3% over 2026-2030. Indonesia accounts for about one-third of total electricity consumption in Southeast Asia and is projected to contribute 38% of the additional demand over the forecast period. Viet Nam is expected to account for 26% of demand growth, followed by Thailand at 11%, with both Malaysia and the Philippines at 8% each.

Coal remains the primary source of power generation in Southeast Asia. Coal-fired output rose by 3.1% y-o-y in 2025 and continued to provide almost 50% of the region's electricity. Coal-fired generation is forecast to grow by an average of 4% annually over 2026-2030 while its share in the electricity mix is expected to ease down modestly over the outlook period. Gas-fired generation is projected to rise by just over 7% on average through 2030, increasing its share of the electricity mix from 24% to 27%.

Renewable generation is projected to expand at a robust pace as countries accelerate the deployment of wind and solar PV across Southeast Asia. Wind is forecast to grow by 26% annually and solar PV by 19% over the forecast period. Together, wind and solar PV are expected to increase their combined share of the electricity mix from around 4.5% in 2025 to about 9% by 2030. Hydropower remains the largest source of renewable generation, accounting for over 60% of renewable electricity in 2025. Its share is forecast to decline to below 50% by 2030 as wind and solar PV generation expand and capture a growing share of the region's renewable electricity growth.

Year-on-year change in electricity generation in Southeast Asia, 2019-2030



Notes: RES = renewable energy sources. 'Other non-RES' includes oil, waste and other non-renewable sources. 'Other RES' includes geothermal, bioenergy, concentrated solar power (CSP) and ocean energy. Data for 2026-2030 are forecast values.

Indonesia

Coal will remain the primary electricity generation source, even as gas-fired output and renewables expand rapidly

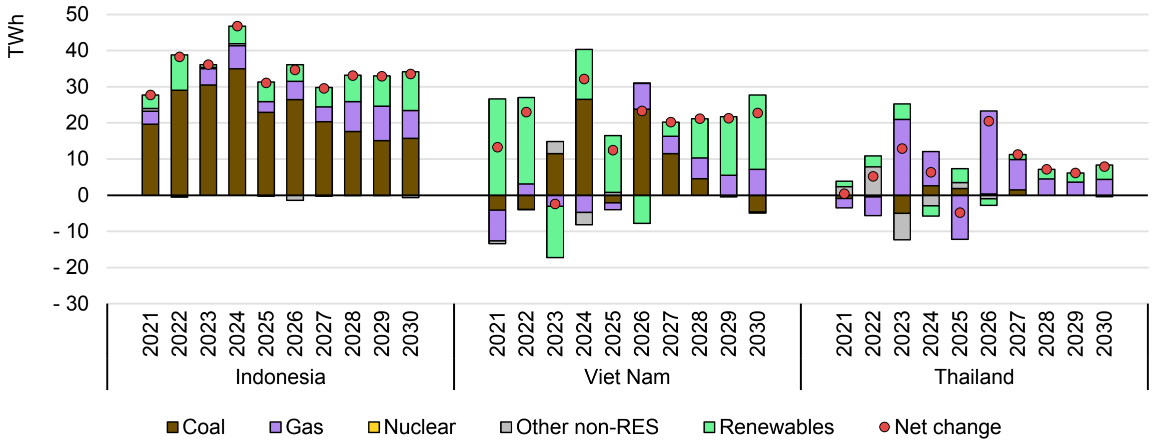
In 2025, Indonesia's electricity demand rose by an estimated 6.7%, moderating amid milder weather compared with the previous year. Growth was supported by industrial expansion as well as increased commercial and household consumption. All major energy sources posted growth, with electricity generation from coal and gas rising by an estimated 7% and 5%, respectively. Renewable energy also expanded by 7.3%, led by surges in wind and solar PV, which grew by about 50% and 40%, respectively. Despite these gains, coal remains the primary source of electricity, accounting for 70% of power generation. Over the forecast period, coal's share is projected to decline modestly, representing approximately two-thirds of power generation by the end of the outlook period.

Electricity demand growth is forecast to resume rising at a robust rate, at near 6% on average annually, from 2026 to 2030. Coal-fired generation is expected to slow to an average 4.8% per year over the outlook period, while gas-fired generation and renewable generation are projected to maintain a stronger pace of just below 9% and 8%, respectively. Within renewables, solar PV and wind are forecast to grow the fastest, at average annual rates of 59% and 52%, respectively. Biomass and hydropower are set to remain the primary renewable sources, accounting for a combined 63% of renewable generation by 2030. Overall, coal's share of the electricity mix falls from 70% in 2025 to 67% by 2030, while renewables will see an increase from 15% to 17% over the period. This change in electricity mix will result in an average annual reduction in emission intensity of 0.7% over the 2026-2030 period.

Indonesia's 2025 policy updates mark a shift towards a more co-ordinated and system-wide energy transition, with clearer alignment across planning, investment and market instruments. The National Energy Policy (Kebijakan Energi Nasional, KEN), revised under Government Regulation No. 40/2025, sets new targets to raise the renewable share to 19-23% by 2030 and to achieve net-zero emissions by 2060, with renewables expected to supply 70-72% of the total national energy mix. Complementing this, the National Electricity Plan (RUKN) 2024-2060 set a goal to reach 105 GW of renewable capacity by 2040, alongside new targets for gas, nuclear and carbon capture and storage (CCS). The RUKN estimates renewables will account for around 50% of the generation mix by 2060. The Power Development Plan (RUPTL), from 2025-2034, operationalises these targets, outlining capacity additions of 16.9 GW in renewables, 3.6 GW in energy storage, 10 GW in gas-fired power plants, and 4 GW in coal-fired plants by 2030. Captive power plants have already started to be formally incorporated into institutional financial frameworks. The JETP captive power study, published in late 2025, projects an average annual growth rate of around 4.6% in captive generation through 2030.

At the project level, the government recently announced a new initiative to build 100 GW of solar PV. This includes 80 GW of village-based distributed solar with 320 GWh of battery storage and 20 GW of utility-scale solar PV. This programme aims to enhance rural electrification and reduce reliance on transmission infrastructure, however, implementation faces technical, financial, and supply-chain challenges. In parallel, Indonesia has strengthened its carbon-market framework through Presidential Regulation No. 110/2025, which introduces carbon-allocation rules, provisions for international trading, measurement, reporting, and verification (MRV) standards. In October 2025, the government formally reopened international carbon trading after a four-year suspension, enabling cross-border transactions under the new regulatory framework.

Year-on-year change in electricity generation in Indonesia, Viet Nam, and Thailand, 2021-2030



Notes: RES = renewable energy sources. 'Other non-RES' includes oil, waste and other non-renewable sources. 'Other RES' includes geothermal, bioenergy, concentrated solar power (CSP) and ocean energy. Data for 2026-2030 are forecast values.

Viet Nam

Over 50% of the demand growth through 2030 is set to be met by rising solar and wind, and 29% by gas-fired power

Electricity demand in Viet Nam increased by just under 3% y-o-y in 2025, based on year-to-date data through October, a sharp slowdown amid milder weather from the strong 12.6% growth rate recorded in 2024. Over the 2026-2030 period, demand is expected to rise at an average annual rate of 6.3%. Wind and solar PV are forecast to meet around 42% of the growth in 2026-2030, with the rest met by coal and gas in similar shares.

Among renewables, wind power generation increased by 15% y-o-y in 2025, which is expected to accelerate to average annual growth of 24% over 2026-2030. Solar PV fell by 5% in 2025 but is forecast to rebound and grow at an average of around 15% per year over the outlook period. Hydropower accounted for about 73% of renewable power generation in 2025, but its share is expected to decline to 50% as wind and solar PV expand. Despite the growing role of renewables, coal remains a major contributor to the electricity mix, representing over 45% of total generation in 2025 and expected to still account for a similar share through 2030.

In early 2025, Viet Nam revised its National Power Development Plan for the 2021-2030 period, with a vision to 2050 (PDP8). The updated plan outlines a substantial increase in the installed capacity of renewable energy by 2030, with notable expansions in solar PV, wind, and hydropower, as well as higher electricity imports. The revised PDP8 also includes an enhanced commitment to developing pumped-storage hydropower plants with a capacity of approximately 2 400 MW, alongside storage batteries totalling around 300 MW by 2030, with the aim to support the integration of large-scale renewable energy sources into the grid. The PDP8 also reintroduces nuclear power into the planning framework, with the goal of commissioning plants totalling 4.0-6.4 GW between 2030 and 2035.

Viet Nam is also strengthening its regional power interconnections through new agreements. By 2030, Viet Nam plans to have electricity import capacity of 9 360-12 000 MW from the Lao People's Democratic Republic, supported by a bilateral agreement between the two countries. On the export side, Viet Nam is aiming to enhance regional co-operation with Cambodia by increasing electricity export capacity to around 400 MW by 2030.

A key infrastructure milestone was reached 19 December 2025 with completion of the expansion of the Hoa Binh hydropower plant, following the successful installation of the rotors for Units 1 and 2. With both units now operational, capacity has been raised by 480 MW to the power grid. The new capacity is expected to improve frequency regulation and overall system stability, as well as reduce system-wide costs.

Thailand

Electricity demand dips in 2025 but is set to rebound while solar deployment accelerates

Electricity demand in Thailand is estimated to have contracted by just over 4% in 2025, based on year-to-date data through September, driven by lower consumption across industry, residential and commercial sectors. The decline follows a high base year in 2024 and is influenced by a number of factors, including cooler weather conditions and La Niña, as well as an economic slowdown. In 2026-2030, demand is expected to grow at an average annual rate of around 4%, led by a rebound in economic growth, electrification in the industry and transport sectors, and the expansion of digital infrastructure, including data centres.

Natural gas remained the largest source of electricity generation, with a share of 62% in 2025, which is expected to rise to around 67% through 2030. By contrast, coal's share in the electricity mix is forecast to gradually decline from 17% in 2025 to 14% in 2030. VRE accounted for 6% of electricity generation in 2025, but its share is expected to rise steadily, reaching 9% by 2030. Solar PV will continue to propel Thailand's renewable energy expansion at an average annual growth of 14% between 2026 and 2030. The Electricity Generating Authority of Thailand (EGAT) is targeting the development of 16 hydro-floating solar projects totalling 2 725 MW of capacity by 2030.

Thailand introduced several policy mechanisms to incentivise renewables in 2025. The Utility Green Tariff (UGT), which is the first green energy procurement option in the country, enables eligible customers to purchase electricity and renewable energy certificates (RECs) from utility-scale renewable projects. The government also introduced a pilot programme for Direct Power Purchase Agreements (DPPAs), with 2 GW of capacity targeted at data centres, which allows producers to sell electricity to buyers. To maintain affordability, the government has introduced measures to cap the residential tariff at 3.94 baht/kWh (Thai Bhat) at the end of 2025, providing cost-of-living relief. In the transport sector, Thailand is targeting zero-emission vehicles to account for at least 30% of total automotive production by 2030. This is expected to boost EV adoption and contribute to higher peak electricity demand in the coming decade.

The draft Power Development Plan (PDP) 2024, which is set to be replaced by a new plan currently in the drafting process, set a target to source 51% of its energy from renewables by 2037. The government has also advanced the net-zero emissions target from 2065 to 2050, reflecting stronger national climate ambitions.

Malaysia

The natural gas share in electricity generation is forecast to rise to 40% by 2030 amid rising demand, while solar PV also grows

Electricity demand in Malaysia grew by 1.3% in 2025, led by stronger residential consumption and continued industrial expansion, particularly in manufacturing and petrochemicals, and the rapid growth of data centres. These sectors will remain the key sources of demand, with electricity consumption projected to grow at an average of 3.2% annually from 2026 to 2030, broadly in line with the historical compound annual growth rate of around 3% recorded between 2018 and 2025.

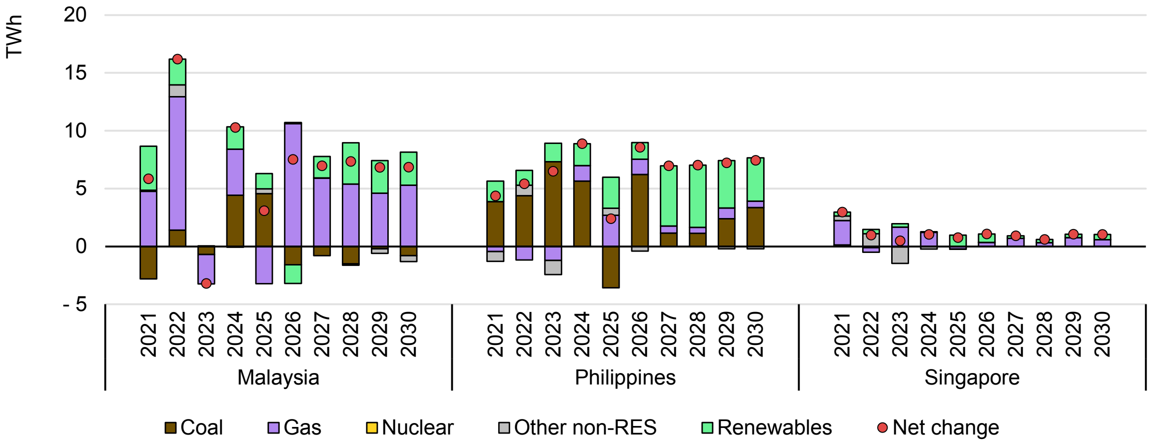
Coal-fired power generation remained the largest source in the electricity mix in 2025, accounting for 46% of total output. However, coal's share is expected to decrease over the outlook period. On the other hand, natural gas is projected to increase its share from 33% in 2025 to 41% in 2030. After falling by around 4.5% in 2025, gas-fired generation is expected to average annual growth of 8% during 2026-2030. This trend reflects Malaysia's positioning of natural gas as not only a transitional fuel but also a primary contributor in the country's National Energy Transition Roadmap (NETR).

Renewable electricity generation in Malaysia increased by around 3.5% in 2025 and is forecast to rise by just under 4.5% per year on average over 2026-2030. This expansion is supported by strong policy initiatives, including the Large-Scale Solar programme and the Corporate Renewable Energy Supply Scheme launched in July 2024, which enables companies to source or supply green power via the national grid. The Solar Accelerated Transition Action Programme (Solar ATAP) was introduced on 1 January 2026 to further expand the use of rooftop space for generating renewable energy from solar PV. It follows the Net Energy Metering (NEM) Programme, which concluded 30 June 2025.

Within the renewables sector, hydropower had the biggest share of generation at 86% in 2025, and this share is expected to gradually decrease over the forecast period. Solar PV generation showed strong momentum in 2025, rising by an estimated 11%, and is forecast to post even higher growth of 25% per year on average between 2026 and 2030, increasing its share in total generation from 2% in 2025 to 5% in 2030.

The government is also investing in grid and infrastructure modernisation, reflected by state utility Tenaga Nasional Berhad's (TNB) announcement of a large grid upgrade investment of USD 10 billion to support the growth of data centres, for which Malaysia is fast becoming a major hub. During its ASEAN chairmanship, it also advanced regional co-operation on grid interconnectivity, with the signing of the Enhanced Memorandum of Understanding for the ASEAN Power Grid.

Year-on-year change in electricity generation in Malaysia, Philippines, and Singapore, 2021-2030



Notes: RES = renewable energy sources. 'Other non-RES' includes oil, waste and other non-renewable sources. 'Other RES' includes geothermal, bioenergy, concentrated solar power (CSP) and ocean energy. Data for 2026-2030 are forecast values.

Philippines

The share of renewables in generation is set to reach 30% due to rapid solar PV growth, while coal also continues to rise

Electricity demand in the Philippines rose by an estimated 2.1% y-o-y in 2025, down from the 8.8% surge in 2024. From 2026 to 2030, demand is forecast to increase at an average annual rate of 5.4%, underpinned by sustained economic growth, industrial development, and wider electrification.

In 2025, renewable electricity generation was up by a record 9.5% y-o-y, from 7.2% in 2024. This was driven by substantial increases in generation from solar PV (+25%), wind (+17%) and hydropower (+12%). The additional renewable output helped to displace more expensive generation sources like diesel and LNG in the Wholesale Electricity Spot Market (WESM), where renewables benefit from preferential dispatch.

Coal-fired generation fell by 4.5% y-o-y in 2025, a sharp reversal from the 7.7% increase posted in 2024. This reduction coincided with outages affecting eight coal plants with a combined capacity of 1.4 GW for more than 30 days in the first quarter of 2025. Coal currently accounts for 59% of electricity generation, with its share projected to decline to approximately 54% by 2030. Natural gas continues to play an important role in electricity generation. Although its annual growth is expected to moderate to an average 3.5% through 2030, down from 15% in 2025, it is set to expand at a sustained pace in contrast to the largely flat trend over the previous decade (2014-2023).

The Philippines has implemented several renewable energy policy mechanisms, including portfolio standards and the Green Energy Auction Program (GEAP). The third and fourth round of the Green Energy Auction (GEA-3 and GEA-4) was conducted in 2025, targeting around 4.65 GW and 10.5 GW, respectively, of new capacity from hydropower, pumped storage hydro, geothermal, solar (ground- and roof-mounted), floating solar and onshore wind. GEA-4 also marked the first auction to integrate 1.1 GW of solar paired with BESS. In GEA-4, the auction secured about 10.2 GW of capacity after the preliminary results awarded 9 423 MW of new renewable capacity, to be delivered between 2026 and 2029. The fifth auction round (GEA-5) was also launched in June 2025, focusing exclusively on offshore wind, with an installation target of 3.3 GW during 2028 to 2030. The Department of Energy also launched a dedicated auction round (GEA-6) for waste-to-energy facilities, targeting project delivery in 2028.

In October 2025, the Department of Energy (DOE) issued Circular No. 2025-10-0019, establishing the policy foundations for the country's first commercially developed and operated nuclear power plant as part of a framework for integrating nuclear energy into the national generation mix. In terms of demand, Phase 1 (2025-2027) of the Demand-Side Management (DSM) Implementation Plan was launched to encourage active load management and efficiency measures. Since 2014, the Interruptible Load Program (ILP) has remained a key demand response tool, with over 100 companies currently enrolled, each providing a combined de-loading capacity of over 500 MW to help stabilise the grid during periods of peak demand or supply disruption. The DOE also initiated stakeholder consultations in July 2025 on a draft policy framework for establishing a capacity market.

Singapore

Gas remains the backbone of power supply, while flexibility, imports, and hydrogen-ready capacities gain importance

Electricity demand in Singapore increased by an estimated 1.4% in 2025, based on year-to-date data through October, following a similar rise of 1.6% in 2024. Growth is expected to average around 1.5% per year in 2026-2030, supported by the continued expansion of data centre capacity and AI, increased adoption of EVs, and rising industrial/advanced manufacturing. Natural gas remains the dominant fuel for power generation, accounting for around 92% of electricity supply in 2025, down slightly from 94% in 2024. The share of renewables remains low at only 6% but is growing steadily and expected to reach 8% by 2030.

Progress on low-carbon electricity imports continued last year. In May 2025, the Energy Market Authority granted Singa Renewables a conditional licence for up to 1 GW of low-carbon electricity import capacity from Indonesia, increasing the total number of projects with conditional licenses to six. These will help Singapore achieve its goal of 6 GW of low-carbon electricity import capacity by 2035, with the Indonesia link expected to start operating around 2029. Singapore met its 1.5 GW solar capacity target at the end of 2024, one year earlier than the initial deadline. By 2030, the country aims to increase this to 2 GW. In 2025, Singapore committed to reduce CO_2 emissions to 45-50 Mt by 2035, down from around 60 Mt by 2030.

The Future Grid Capabilities Roadmap was launched in 2024 to support higher penetration of distributed and flexible resources such as distributed energy resources, BESS, EV charging and demand response. In 2025, Singapore also updated wholesale market rules so that energy storage systems can submit both charging and discharging quantities to reflect their capabilities where state of charge is introduced as one of the dispatch constraints.

Investment in hydrogen-ready and fast-start generation is progressing. In January 2025, PacificLight Power was granted permission to build, own and operate a hydrogen-ready combined-cycle gas turbine (CCGT) unit with a capacity of at least 600 MW. Scheduled to begin operation in 2029, the plant will be the first CCGT in Singapore integrated with BESS. In May 2025, PacificLight completed the construction of the country's first at 100 MW hydrogen-ready fast-start gas turbine facility providing ancillary services, which will provide additional resilience in the event of system disturbances or outages.

Further enhancing reliability, Meranti Power’s 682 MW open-cycle gas turbine (OCGT) power plant became operational in June 2025 to enhance system security during peak periods and generation disruptions. This plant also has the capability to draw on up to 30% hydrogen.

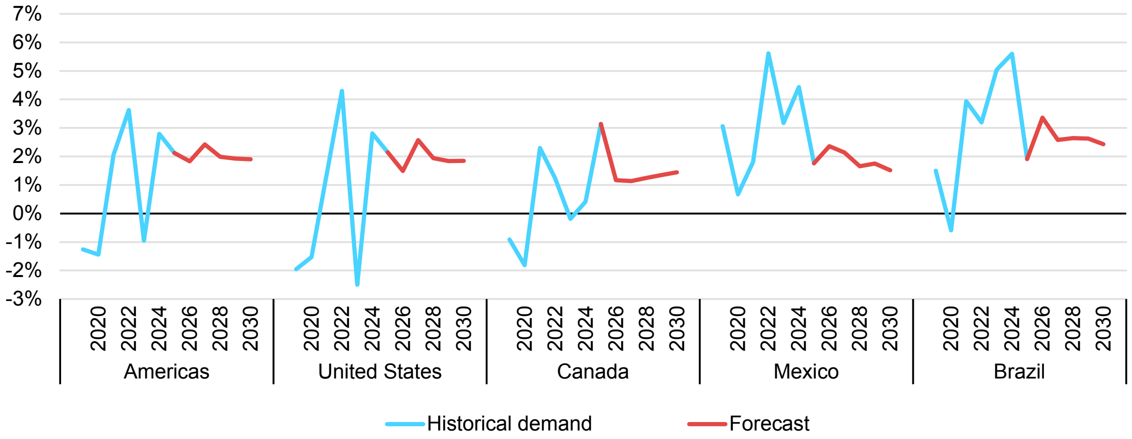
Americas

Solar PV and natural gas-fired generation see strong growth through 2030

In the Americas, electricity demand grew by 2.1% in 2025, compared with 2.8% a year ago, when intense heatwaves in a number of countries increased consumption. By contrast, milder weather contributed to moderation in demand growth in 2025, especially in Brazil and Mexico. Extreme weather events, such as heatwaves and colder or warmer winters, will continue to affect peak loads and demand significantly in the region, injecting higher levels of volatility into forecasts.

Over the 2026-2030 forecast period, we expect demand growth to average around 2% annually, roughly double the pace of the past decade. The United States, the world's second largest electricity consumer after China, will account for more than 60% of the growth in the Americas during the outlook period. The massive expansion of data centres from burgeoning growth in AI and cloud services propel demand higher in the region, especially in the United States, where they make up more than half of the total increase through 2030, while Brazil, Canada, Chile and Mexico, are also emerging as significant players.

Year-on-year percent change in electricity demand, Americas, 2019-2030

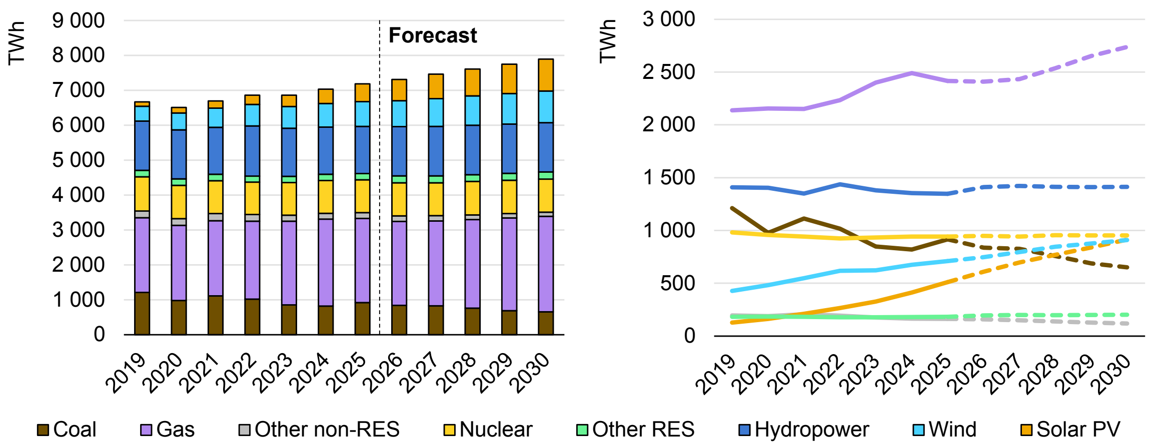


Notes: Data for 2026-2030 are forecast values. The plots start from 2019, whereas the x-axis labels are shown only for the even years due space constraints.

The Americas accounts for 30% of global hydropower generation and posted stable year-on-year output in 2025. Nevertheless, there were variations across the region, with North America seeing higher hydropower generation year-on-year, while it was lower in Central and South America. We expect coal-fired generation in the region to decline through 2030, with sustained growth in solar PV and gas-fired output, together with wind, meeting the additional demand through the end of the decade. Electricity generation from wind and solar PV are each projected to surpass coal use over the outlook period.

Technical curtailment of renewables is emerging as a challenge in numerous countries with rapid VRE growth, such as Brazil and Chile, highlighting the need for greater system flexibility and improved grid management. At the same time, investments in BESS and transmission projects across the region are accelerating to reinforce system flexibility.

Electricity generation by source in Americas, 2019-2030



Notes: RES = renewable energy sources. 'Other non-RES' includes oil, waste and other non-renewable sources. 'Other RES' includes geothermal, bioenergy, concentrated solar power (CSP) and ocean energy. Data for 2026-2030 are forecast values.

United States

Electricity demand growth underpinned by the rapid expansion of data centres and industry

Electricity demand in the United States rose by 2.1% in 2025, after 2.8% in 2024, when hot summer temperatures bolstered consumption. In both 2024 and 2025, the buildings sector (residential and commercial combined) accounted for more than 70% of US electricity demand growth. Alongside robust economic growth and expanding data centres, demand growth in 2025 was supported by higher space heating needs due to colder winter temperatures, with about 10% higher heating degree days (HDDs).

For the 2026-2030 period, US electricity demand is forecast to rise on average by around 2%, more than twice the rate observed over the past decade (2016-2025).

Data centres' electricity consumption is expected to account for almost half of the projected growth. Demand growth in the buildings sector, excluding data centres, will also remain significant. The industrial sector – including new industries with large loads such as semiconductor production and battery manufacturing – will be another major contributor to growth.

The impact of the expanding electricity load is highlighted by the North American Electric Reliability Corporation (NERC) in its 2025-2026 Winter Reliability Assessment. The report noted that, while resources are adequate for a normal peak winter demand season, wide-area cold snaps could pose challenges for the system relative to capacity growth. Winter electricity demand (December-February) is reportedly increasing at the fastest rate in recent years, especially in regions with new build data centres.

As of 2025, more than 150 GW of solar PV and wind projects in late-stage development were in grid connection queues in the United States. Similarly, substantial capacities of battery storage and other industrial large loads are waiting for connection. In October 2025, the US Secretary of Energy directed the Federal Energy Regulatory Commission (FERC) to initiate rulemaking procedures to accelerate the grid connection of large loads, including data centres. Among other measures, the proposed rule would allow the joint filing of co-located load and generation interconnection requests. This would reduce the review period, grid upgrade costs, and the time needed for the commissioning of additional generation. These issues are covered in more detail in a dedicated chapter on 'Grids' and unlocking capacity.

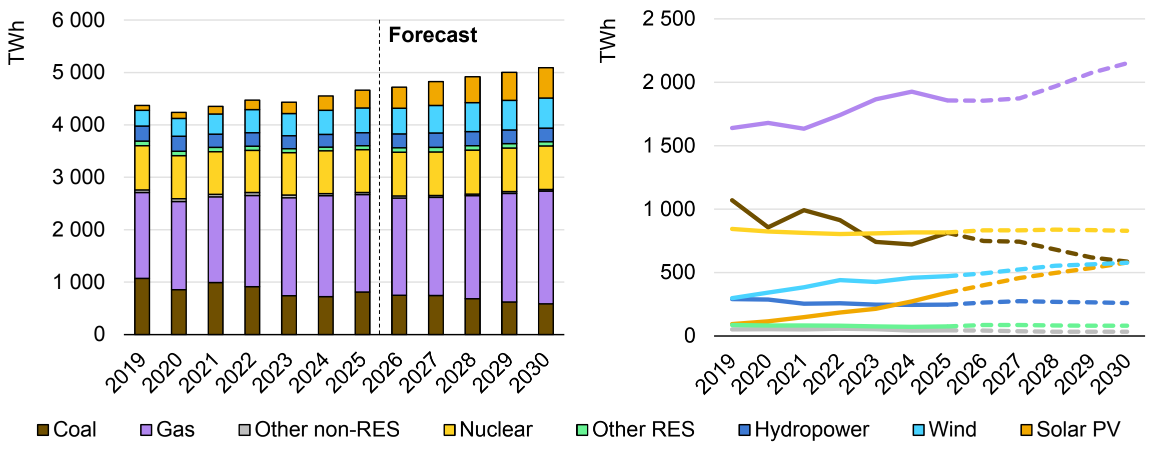
Gas-fired generation is set to grow strongly, along with sustained increases in solar PV generation

Coal-fired generation increased by a sharp 13% y-o-y in 2025 amid robust electricity demand growth, rebounding from a contraction of almost 3% in 2024. This was supported by higher natural gas prices in 2025 versus year-ago levels. Correspondingly, gas-fired generation declined by 3.6%. Renewable output rose by more than 8%, with higher solar PV generation alone (+70 TWh) accounting for 80% of the increase. Solar PV output was 26% higher year-on-year, similar to its 2024 growth rate. By contrast, wind generation slowed to 2.9%, versus 7.6% in 2024.

Over the five-year outlook period, aggregate electricity generation is forecast to rise by 430 TWh, with natural gas and solar PV set to meet most of the additional demand. Gas-fired generation is set to grow on average by 3% over the forecast period, faster than the average 2.1% in the previous five years. By contrast, coal-fired generation is expected to fall by an annual average 6% in 2026-2030, however the decline rate is highly dependent on the progression of coal retirements and could be revised given the support for coal by the current US Administration. The government took measures to delay retirement of coal power plants amid strong growth in electricity demand last year, in part due to rapid growth in data centres. The policy reversal led to planned retirements slowing significantly in 2025. While earlier projections showed 15 GW of coal power plant retirements in 2025, the latest forecast for capacity closures is just 6.2 GW. However, as of November 2025, less than 1 GW had been retired.

Renewable generation in the United States is forecast to increase at an average annual rate of 5.7% per year. This is largely supported by solar PV generation, which is projected to rise at an average 10% per year, approaching coal-fired output levels by the end of the decade, albeit with the caveats regarding coal retirements. Wind generation is set to grow at a more moderate annual average of 4% to 2030.

Electricity generation by source in the United States, 2019-2030



Notes: RES = renewable energy sources. 'Other non-RES' includes oil, waste and other non-renewable sources. 'Other RES' includes geothermal, bioenergy, concentrated solar power (CSP) and ocean energy. Data for 2026-2030 are forecast values.

According to the IEA's latest *Renewables 2025* report, almost 250 GW of renewable energy is forecast to be deployed in 2026-2030, 70% of which is utility-scale solar PV, 13% distributed solar PV, and 17% wind. This is a downward revision of almost 50% from the previous forecast to account for recent policy changes, including various executive orders announced between January and July 2025 and the phase-out of tax credits and other provisions in the "One Big, Beautiful Bill Act" (OBBBA).

Increasing nuclear generation is a major focus, with new policies in place to further expand capacity

Nuclear generation was essentially flat in 2025, after increasing near 1% in 2024. Growth is forecast to average 0.3% per year out to 2030. The passage of the OBBBA in July 2025 placed significant focus on domestic energy sources, with nuclear energy poised for renewed growth, supported by continued tax credits, increased financing, and removal or reduction of regulatory barriers.

Near term, project restarts are moving apace. Following the commissioning of Vogtle 4 (1 250 MW) in 2024, Three Mile Island 1 (880 MW) is expected to be restarted in 2027, one year earlier than planned. The reactor, which was shut down in 2019 for economic reasons, is to be renamed the “Crane Clean Energy Center.” Similarly, the Duane Arnold nuclear power plant (624 MW), which was closed in 2020 after severe storm damage made repairs uneconomical, is scheduled to be restarted by early 2029, following an agreement between US utility NextEra and technology company Google. The restarted plant will help meet Google’s low-emissions electricity needs to power its cloud and AI infrastructure.

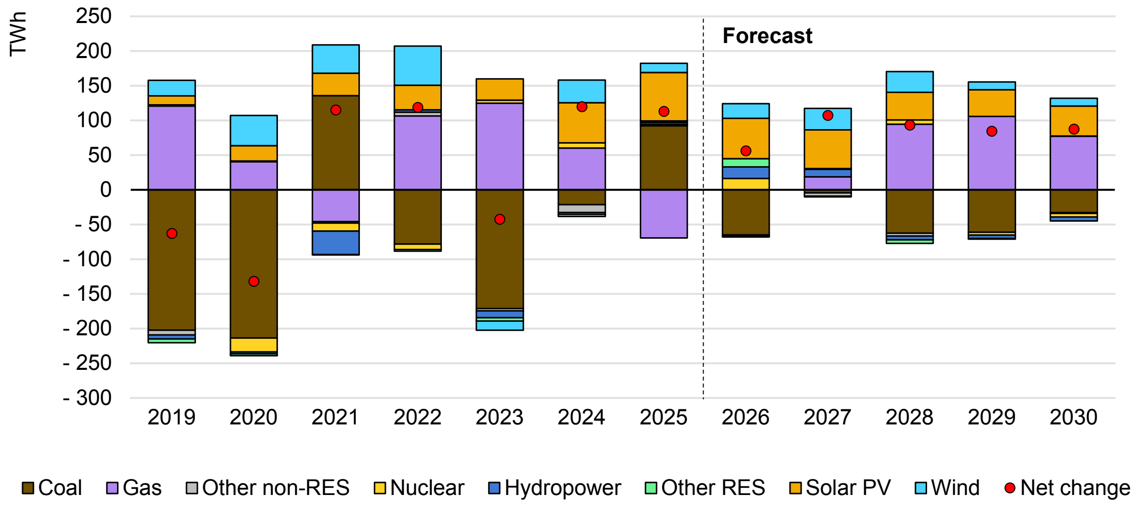
The United States is a forerunner in the field of SMR technologies, with the federal government supporting the development of multiple designs. The Advanced Reactor Demonstration Program provides funding for SMRs and other advanced reactor designs.

Tech companies are also major supporters of new SMR projects, with initial deployments slated for early to mid-2030s. TerraPower, founded by Microsoft’s Bill Gates, is constructing a 345 MW sodium-cooled reactor in Kemmerer, Wyoming, with commercial operation targeted by 2030. Kairos Power, in collaboration with Google and the Tennessee Valley Authority (TVA), is currently building the Hermes SMR fuel plant in Oak Ridge, Tennessee, which will be the first of its kind in the country. The main power-producing facility, Hermes 2, is slated to supply up to 50 MW of electricity to the TVA grid by 2030, as part of a larger deal with Google to bring 500 MW of advanced nuclear capacity online by 2035.

In yet another tech-led project, working with Amazon and Dow Inc., X-energy plans to deploy Xe-100 units of 80 MW for a combined capacity of 320 MW at Dow's Seadrift site in Texas in the 2030s. Meanwhile, Oklo is building Aurora, an advanced, small liquid metal-cooled fast reactor (LMFR), designed for 50-75 MW. Developed at the Idaho National Laboratory to power local data centres, the reactor will utilise recycled nuclear fuel (HALEU). Under the DOE's Reactor Pilot Program, Oklo Aurora is targeting late 2027 or early 2028 for operation.

There is also strong momentum behind enhanced geothermal energy, with multiple large-scale projects now under construction and expected to become operational over our forecast period. Geothermal electricity generation in the United States is forecast to grow by nearly 5% per year on average through 2030.

Year-on-year change in electricity generation in the United States, 2019-2030



Notes: RES = renewable energy sources. 'Other non-RES' includes oil, waste and other non-renewable sources. 'Other RES' includes geothermal, bioenergy, concentrated solar power (CSP) and ocean energy. Data for 2026-2030 are forecast values.

Canada

Electricity demand reverses course, rising every year out to 2030, with gas and renewables set to meet additional growth

Electricity demand in Canada is estimated to have risen by just over 3% y-o-y in 2025, based on data through October, after an increase of just 0.4% in 2024. Colder winter temperatures, with almost 10% more heating-degree-days compared to previous year, contributed to growth. Nuclear generation grew by 3% while total renewable generation was up by 2.5%, mainly driven by higher hydropower and wind output. Hydropower generation rebounded to growth of more than 1%, after two consecutive years of decline in 2023 (-9.3%) and 2024 (-4.9%). In line with this recovery, the Site C hydropower plant (1 100 MW) in British Columbia was completed, with all units fully operational by August 2025. Wind generation increased by 9% and solar PV by 13%. Despite higher output from low-emissions sources, fossil-fired generation was stronger amid robust demand. Gas-fired output was up by around 4.5% and coal-fired generation increased by 8% in 2025.

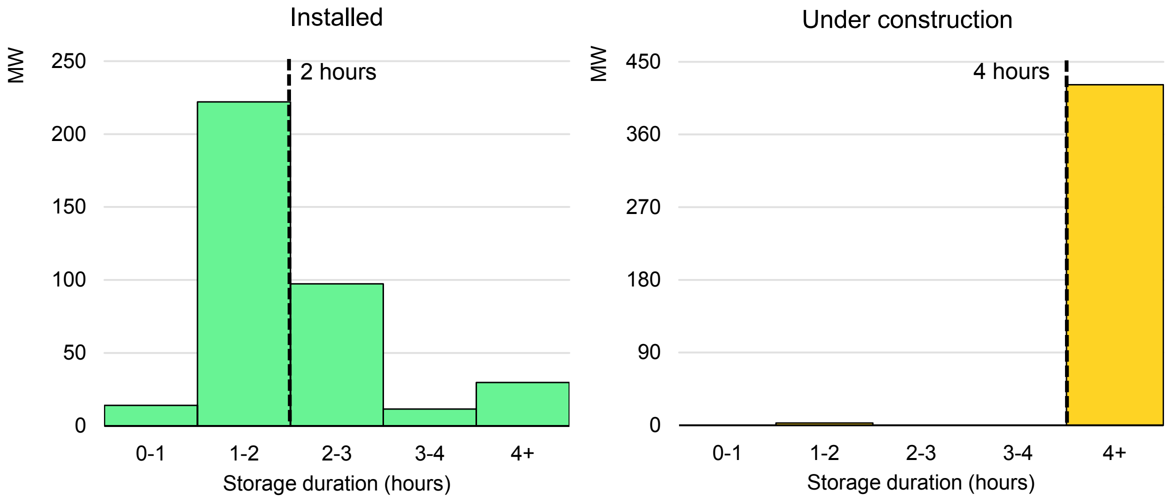
Electricity demand in Canada, which had effectively been flat over the past decade, is now reversing trend and set to increase by 1.3% on average every year out to 2030. This will be supported by data centres, alongside electrification of heating and transport sectors. Solar PV and wind generation are forecast to continue expanding, at annual average rates of 13% and 7%, respectively. Their combined share in total electricity generation is expected to reach 13% in 2030, up from 9% in 2025. Similarly, renewable energy sources (RES) in total are projected to account for 70% in 2030, up from 66%. As the share of RES in electricity supply increases, we expect coal-fired generation to drop at a faster pace, falling on average by 21% per year over the forecast period. By contrast, growth in natural gas-fired generation is forecast to average 1% per year through 2030.

Nuclear generation in Canada is expected to remain close to 2025 levels in 2030, after a decline as Pickering 5-8 (4 x 540 MW) reactors enter refurbishment at the end of 2026, before bouncing back as the Bruce 3-5 (3 x 870 MW) and Darlington 4 (930 MW) refurbishments are completed. The refurbishments are major life-extension projects for Ontario's nuclear fleet of 30 years or more. Canada’s first SMR is planned at the Darlington New Nuclear Project site, with the final investment decision given in May 2025. Ontario Power Generation is set to construct the first of the four planned BWRX-300 SMR units, which is slated to become operational by the end of 2030.

According to the Canada Energy Regulator, battery energy storage systems (BESS) are the fastest-growing and the dominant source of storage in the country. Government support for storage projects is gaining pace, with the Smart Renewables Electrification Pathways programme announcing in October 2024 additional funding of CAD 500 million (Canadian dollar) for its Utility Support Stream.

Installed capacity of battery energy storage systems larger than 1 MW reached 552 MW at the end of 2024, with an additional 597 MW under construction that could increase capacity to 1 149 MW in 2030 and a further 2 768 MW with regulatory approval. Installed BESS projects to date have an average power capacity of around 10 MW and an average storage duration of 2 hours. However, the market is shifting toward larger systems with greater energy volumes. Projects under construction average about 45 MW with a 4-hour duration. Looking ahead to 2030, proposed projects are even bigger, with average capacities of around 100 MW while maintaining a 4-hour storage duration.

Distribution of total capacity and duration of battery storage projects in Canada that are installed (left) and under construction (right), July 2025



IEA. CC BY 4.0.

Notes: Each band on the x-axis represents the range of values covered by that interval. For example, 0-1 includes all values greater than or equal to 0 and less than 1, 1-2 includes values from 1 up to but not including 2, and so on. The final band (4+) includes all values greater than or equal to 4. Battery storage projects with unreported duration are excluded. The dashed lines indicate the capacity-weighted average duration across projects.
Source: IEA analysis based on data from CER (2025).

Mexico

Rising renewables are set to displace coal and oil power generation, but logistics remain a key risk for regional reliability

Mexico's electricity demand is estimated to have grown by around 2% in 2025, following an increase of near 4.5% in 2024, driven by intense heatwaves. Similarly, in 2025, peak demand reached record levels in May as extreme heat pushed cooling loads sharply higher, placing sustained stress on the system. Over the medium term, electricity demand is expected to grow by around 1.9% annually between 2026 and 2030, slower than the 3.4% average recorded from 2018 to 2025. The outlook is subject to uncertainty related to the 2026 renegotiation of the United States-Mexico-Canada Agreement (USMCA), which may influence industrial investments and trade flows.

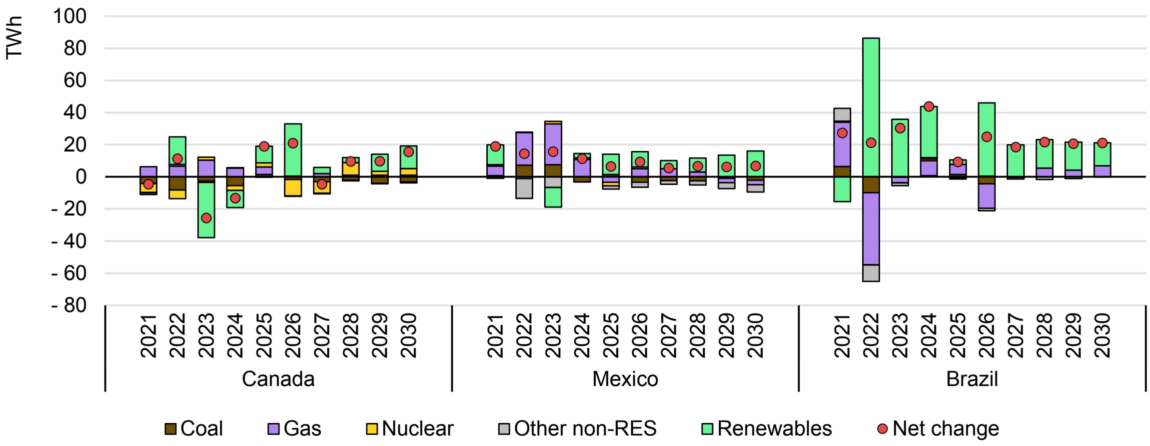
On the supply side, we forecast the share of renewables in generation will increase to 32% in 2030, up from 22% in 2025. This is driven in particular by strong growth in solar PV generation, which is set to surpass the combined output from hydropower and wind over the forecast period. Rising renewables are expected to reduce coal-fired power generation by an average of around 8.5% per year between 2026 and 2030, and oil-fired output by an average of 13% per year. By contrast, natural gas-fired generation is forecast to remain stable, close to its 2024 levels in 2030.

The country's power system continued to rely heavily on natural gas in 2025, while hydro output improved compared with previous years due to more favourable rainfall levels. However, the year also revealed persistent structural vulnerabilities. A major outage in the Yucatán Peninsula that affected more than two million users highlighted the region's longstanding gas infrastructure constraints and the frequent need to rely on diesel generation. Despite adequate installed capacity, fuel logistics and network configuration remain key risks for regional reliability.

Regulatory developments played a defining role for the electricity sector in 2025. A broad reform package introduced a new Electricity Sector Law, reorganised the governance of the state-owned utility Federal Electricity Commission (CFE), and consolidated regulatory oversight under a new National Energy Commission within the Ministry of Energy. The reforms increased the permitted size of private self-supply projects from 0.7 MW to 20 MW as well as established new secondary regulations covering planning, permitting and system development. These measures significantly expand the state's role in the sector while setting clearer boundaries for private participation.

At the same time, the government announced the "Strengthening and Expansion Plan for the National Electric System (2025-2030)", targeting around 29 000 MW of new capacity and more than MXN 600 billion (Mexican pesos) in investment. Clean energy remains a stated priority, with ambitions to reach 45% of capacity by 2030, although investor confidence may depend on the implementation of the new framework. The capacity market was also reformed to introduce subregional zones, improve locational investment signals and better align resource adequacy with regional needs. Significant private sector activities also took place in 2025 in Mexico's power market, including the acquisition of Iberdrola's 2.6 GW portfolio and its sizeable renewables pipeline by Spain's Cox.

Year-on-year change in electricity generation in Canada, Mexico, and Brazil, 2021-2030



Notes: Other non-renewables include oil, waste and other non-renewable sources. Data for 2025 are preliminary. Data for 2026-2030 are forecast values.

Brazil

The share of solar PV and wind in electricity generation is set to surpass the one-third mark over the forecast period

Electricity demand in Brazil is estimated to have grown by around 2% in 2025, based on data through November, following an exceptional 5.6% increase in 2024, which was buttressed by above-average temperatures. Demand is projected to expand at an average annual 2.7% in 2026-2030, compared to GDP growth of around 2.3% per year over the period.

Renewables will meet all of the additional electricity demand over our forecast period. Solar PV generation remains by far the fastest-growing source, increasing by 25% in 2025 and by an average 13% from 2026-2030. By the end of the decade, solar PV is expected to surpass wind to become the second largest renewable source of electricity supply in the country, after hydropower. Wind generation rose by 10% in 2025 and is forecast to grow at a more moderate pace of 5% per year on average to 2030. In total, the share of VRE in total generation is set to rise from 27% in 2025 to 36% by 2030.

Hydropower output declined by 6% y-o-y in 2025. While hydropower will continue to remain the largest source of electricity supply in Brazil, its share in total electricity generation is expected to decline gradually as solar PV and wind generation rise, falling to 46% by 2030 from 52% in 2025, and 63% in 2020.

Gas-fired generation is projected to account for approximately 6% of the electricity mix over the forecast period, while coal and oil-fired generation remain marginal at below 2% of total output through 2030. The emission intensity of power generation increased by around 8% in 2025 to over 70 g CO_2/kWh, but it is still around 30% lower than in 2020, and it is projected to drop to 50 g CO_2/kWh by the end of the decade. This trend consolidates Brazil's power generation emission intensity as one of the lowest in the world.

Between 2020 and 2025, Brazil added over 62 GW of solar PV capacity, of which almost two-thirds were in distributed, non-curtailable installations. Distributed solar PV additions have been supported by a net-metering scheme, and despite a policy change in 2023, low upfront costs and high retail prices have encouraged massive adoption. Following the creation of ReData, which incentivises the installation of data centres, grid connection requests from these projects increased by 32%, reaching 26.2 GW from 19.8 GW, between September and November 2025, according to the government's energy research office, EPE. If all proposed projects were built, this load would represent more than one-quarter of Brazil's total electricity demand.

The rapid growth of solar PV, wind and distributed generation, combined with the emergence of large new electricity loads such as data centres, is already affecting grid operations and may require more complex grid management practices. Curtailment of solar and wind generation has been increasing in Brazil in recent years, reflecting ongoing grid constraints and limited system flexibility. In 2025, curtailment of wind and solar power reportedly surpassed 20%, up from less than 10% in 2024 and under 4% in 2023. In 2025, Brazil curtailed around 37 TWh of renewable energy from wind and solar power.

A notable event occurred on Sunday, 10 August 2025, which was managed successfully without any impact to reliability. The incident occurred on the Father's Day holiday, when very low demand coincided with exceptionally high solar output. Around midday, distributed solar PV supplied almost 40% of total electricity, pushing the system toward its minimum-load limits and requiring substantial curtailment to maintain stability. In response, the national system operator (NSO) reduced hydro and thermal power, and also curtailed around 98% of the programmed utility-scale wind and solar power output. While no outage occurred, the episode illustrated how overgeneration during sunny weekends with low demand is becoming a recurring challenge in a system with rapidly expanding shares of VRE.

The government advanced several measures to reinforce system security and modernise market rules. The Provisional Measure No.1 300, 21 May 2025, launched a broad reform of the electricity sector, expanding the opening of retail markets for commercial and industrial consumers, adjusting tariff design by reallocating charges to reduce costs for low-income consumers, and creating a "Supplier of Last Resort" framework in the event a provider defaults. At the same time, the planned LRCAP 2026 Capacity Reserve Auction, now under public consultation, is expected to introduce strengthened requirements for firm capacity and operational flexibility. Forthcoming auctions are also likely to allow battery storage and other flexible technologies to compete alongside conventional generators, a shift aligned with the system's evolving needs.

While sustaining rapid renewable expansion, it is also essential to strengthen grid infrastructure, expand access to flexibility resources and improve co-ordination across institutions. Against this backdrop, the Brazil Energy Policy Review 2025 provides various recommendations, emphasising review of institutional and market frameworks, promoting flexibility, advancing retail market reform and updating the distributed PV net-metering scheme, among others.

Chile

Strong rise in renewables is constraining fossil-fired generation, rapidly reducing the CO_2 intensity of the power system

Renewables continue to expand their dominance in Chile's electricity mix amid moderate demand growth. In 2025, electricity demand remained flat compared to 2024. A roughly 21% decline in hydropower output from 2024 levels – the highest hydro output since 2006 – was partially offset by a 12% increase in combined wind and solar generation. As a result, renewables generated about 68% of Chile's electricity in 2025. Based on current projects and market trends, the renewable share is expected to surpass the 90% mark by 2030, with wind and solar PV together accounting for over 60% of total generation. Over 2026-2030, we forecast renewable output to expand by around 9% per year on average, outpacing demand growth of just over 3% annually. This shift would reduce the CO_2 intensity of electricity generation in Chile to about one-quarter of its 2025 level by 2030. CO_2 intensity has already halved since 2020 amid surging renewables share.

In addition to expanding renewable generation, Chile is advancing key projects in grid transmission and battery storage. In November 2025, Chile's environmental evaluation service approved the environmental impact assessment of the 3 GW Kimal-Lo Aguirre HVDC transmission line project. This involves approximately USD 1.5 billion investment for over 1 300 km of line, and is scheduled to enter operation around 2029, linking solar-rich areas in the north of the country with demand-heavy areas near the capital city. In parallel, several utility-scale storage or hybrid projects have been inaugurated or announced, aiming to smooth high-VRE output and reinforce system flexibility. In April 2025, Latin America's first large-scale stand-alone battery storage facility (200 MW/800 MWh), the 'BESS del Desierto' project, was inaugurated. In the same month, Chile also launched Latin America's largest solar and battery project, the Quillagua facility (220 MW of solar PV/1.2 GWh BESS capacity). In addition, the country has multiple large-scale hybrid solar-storage projects under development, such as the Oasis de Atacama complex targeting 2 GW of solar PV and 11 GWh of battery storage capacity. Overall, as of December 2025, Chile has an installed capacity of 1.6 GW of battery systems, with an additional 0.7 GW in the testing phase and 6.8 GW under construction.

In 2025, Chile also advanced its strategic policy and regulatory framework to support power system modernisation and decarbonisation. In June, the Ministry of Energy published a regulatory roadmap for H2 2025, setting out secondary regulations to be issued on system operations and distributed generation, transmission planning, which are needed to implement the Energy Transition Law enacted in December 2024. In October, the Power Sector Decarbonisation Plan was published, establishing 28 measures to achieve a coal-free, resilient and efficient power system, focusing on four key areas: project development, strategic system planning, transmission grids, and secure and flexible systems under high renewable penetration.

Colombia

Security of supply is receiving increasing attention amid delays in the construction of generation and transmission assets

In 2025, electricity demand in Colombia is estimated to have increased by close to 1% y-o-y. Following a year of severe droughts which led to water restrictions, low hydropower generation and outages in 2024, Colombia's electricity system recovered in 2025, mainly thanks to an increase of around 20% in hydro output. As reservoirs reached more than 80% of capacity in July, the Ministry of Mines and Energy enabled exports again of electricity from sources other than thermal, which had been restricted for about a year. Gas-fired generation decreased by close to 50% and coal-fired generation fell at a similar rate. Solar PV continued its expansion, with more than 30% increase in generation, as installed capacity surpassed 3 GW under the 6 GW Plus plan.

Colombia faced energy security issues in 2025, as natural gas imports were constrained during Q4 by planned maintenance at its LNG regasification terminal in Cartagena. This led to gas prioritisation in the Caribe region to ensure sufficient supply to power plants and residential consumers, while industries could only use remaining volumes.

Given high price levels and volatility episodes in recent months, the government issued a decree with the objective of reducing exposure of end users to spot market trends by prioritising long-term contracts. Specifically, the decree mandates a minimum of 95% of hydropower hourly output must be sold via long-term contracts instead of the spot market. Generation companies in Colombia oppose this measure, concerned that it threatens market rules and cannot be put in practice in periods of low hydro resources. Long-term contracts currently account for 85-90% of output in Colombia.

Ensuring sufficient electricity supply to cover growing demand amid domestic gas and hydro constraints has become one of the main challenges for Colombia's long-term energy security. Since 2020, the country has struggled with significant delays in development of new generation assets and transmission infrastructure. Overall, during the last six years, only 4.2 GW were commissioned out of 23.6 GW of planned capacity additions, while 88% of major transmission grid projects registered by Colombia's mining and energy planning unit UPME are delayed by an average of 2.5 years. One of the main causes of project hold-ups is the time required for prior consultation and environmental licensing procedures, which in turn become a bottleneck for generation assets to have access to grids.

In terms of interconnections with neighbouring countries, the government is carrying out studies for the construction of a 400 MW high-voltage direct current (HVDC) line between Panama and Colombia (ICP), with a 130 km underwater section, in addition to the development of new high-voltage lines in both countries. If successful, the interconnection is expected to start operations in 2028 and would reinforce regional integration while enabling exports of Colombia's VRE to the Siepac grid, covering Central America.

Costa Rica

Higher hydropower output in 2025 resulted in reduced oil burn in the power sector

Electricity demand increased moderately, by about 1% y-o-y in Costa Rica in 2025. Hydropower output, which typically accounts for 70% of total generation in the country, rose by 20% y-o-y as reservoir levels recovered from severe droughts in previous years. Favourable conditions drove a 25% rise in wind generation, while solar PV remained under 1% of the mix, despite a 42% y-o-y rise in supply. Geothermal output decreased by around 5% y-o-y. These trends resulted in an 87% drop in oil-fired generation, which had peaked at 1.3 TWh in 2024.

Costa Rica's generation expansion plan for 2024-2040, published in May 2025, expects yearly electricity demand growth of 14% and peak load of 11% between 2025 and 2030 in its base case. This will require significant capacity additions in the coming five years for all sources, including backup thermal capacity. In addition, the national utility ICE announced that some of the main hydro plants in the country are expected to undergo major maintenance by 2028, covering structural works, equipment upgrades and technical improvements, with the goal of extending their lifetime without impacting supply. A proposed law aimed at opening the generation market to greater competition (Ley de armonización del sistema eléctrico nacional) continued its course through the legislative process in Costa Rica. If approved, this law would cancel the 15% cap imposed on privately-owned renewable capacity, enabling further private investment in VRE assets.

Costa Rica's transmission infrastructure will benefit from plans by the Central American Bank for Economic Integration (CABEI) to finance a second circuit for SIEPAC, the 1 800 km regional electricity transmission system connecting six Central American countries. The project will increase operational capacity by 300 MW in the interconnection section between Nicaragua and Costa Rica, among other developments.

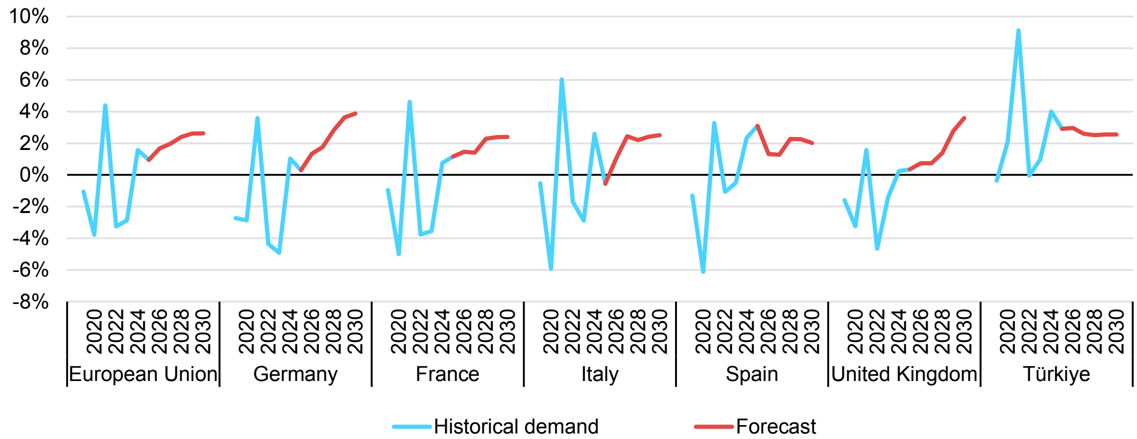
EV penetration rates continue to increase, making it one of the leaders in the region. At the end of 2024, Costa Rica had the highest EV market share in Latin America (15%), and its EV fleet reached close to 23 000 vehicles, only behind far more populous countries like Brazil and Mexico. As a result, EVs are emerging as a major catalyst of electricity demand growth in the country.

Europe

Power demand is increasingly met by renewables while coal use falls rapidly

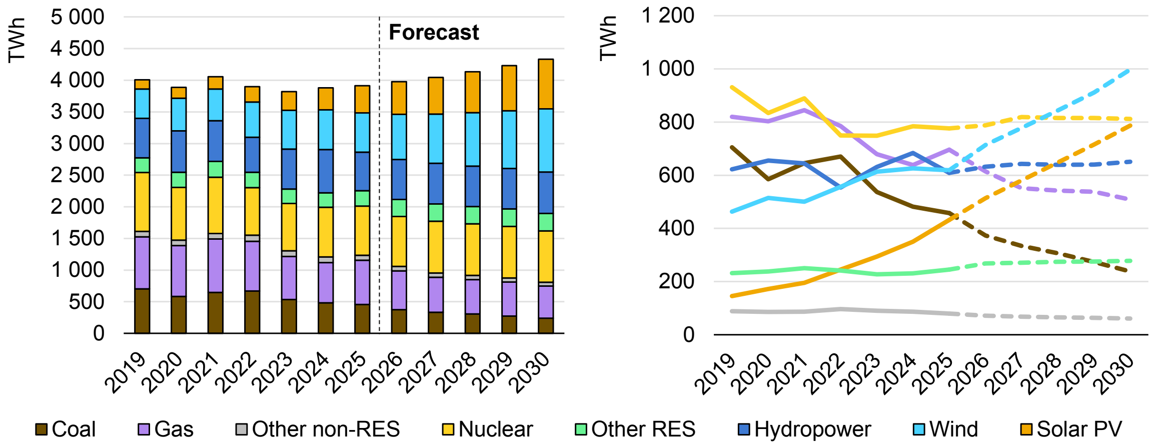
Electricity demand in Europe continued its moderate recovery in 2025, up by about 1% versus a 1.5% increase in 2024, following two years of consecutive contractions in 2022-2023. Europe's demand largely tracks EU trends, which accounts for over 70% of regional electricity use. Rising demand from heating and transport end-use sectors amid electrification has contributed to growth, together with expanding data centres. However, industrial electricity use has remained relatively stable, following declines in 2022 and 2023, and a slight increase in 2024. Assuming industrial demand recovers alongside other sectors, we expect faster European electricity growth of 2.3% on average in our five-year 2026-2030 outlook.

Year-on-year percent change in electricity demand in Europe, 2019-2030



Notes: Data for 2026-2030 are forecast values. The plots start from 2019, whereas the x-axis labels are shown only for the even years due to limited space.

Electricity generation by source in Europe, 2019-2030



Notes: RES = renewable energy sources. 'Other non-RES' includes oil, waste and other non-renewable sources. 'Other RES' includes geothermal, bioenergy, concentrated solar power (CSP), and ocean energy. Data for 2026-2030 are forecast values.

European Union

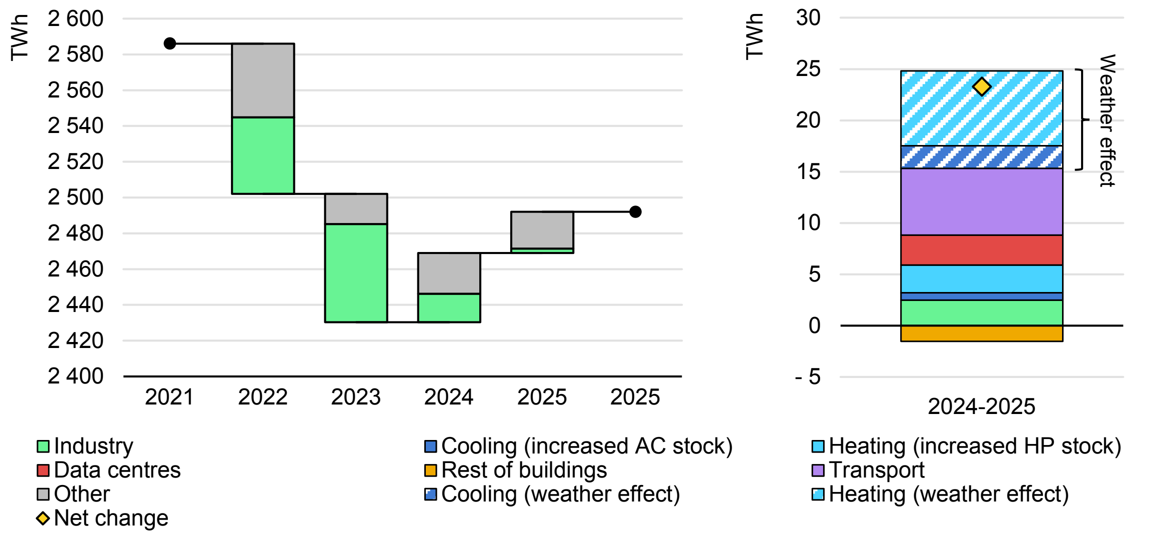
Electricity demand is expected to grow faster over the forecast period, following a timid recovery in 2024-2025

The European Union's electricity demand rose by 0.9%[1] y-o-y in 2025, following an increase of 1.6% in 2024. Industrial electricity demand stayed relatively flat, following a slight increase in 2024, after two consecutive years of declines. The increases were largely driven by the buildings sector, with demand boosted by space heating spikes from severe cold weather early in the year followed by a rise in summer cooling needs amid extreme heatwaves. Growth in the power sector was also supported by the continued deployment of heat pumps, the expansion of data centres, and by the transport sector as the number of EVs continued to rise.

Total electricity demand growth in the European Union is forecast to average 2.3% annually over 2026-2030. While this may appear high, it comes after consecutive substantial declines in 2022 and 2023, which were only followed by a lacklustre recovery in 2024 and 2025. Hence, in our forecast, EU electricity demand is not expected to go back to 2021 levels before 2028. Demand will be driven by continued uptake of electric vehicles and heat pumps, the expansion of data centres, and the assumption of a gradual recovery and electrification in the industrial sector.

[1] These electricity demand growth estimates account for the increasing self-consumption from distributed generation.

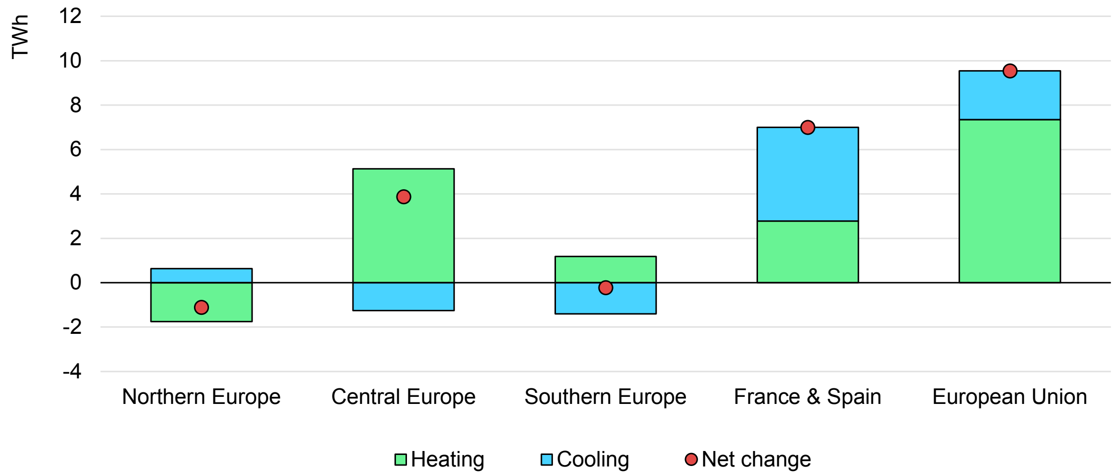
Estimated drivers of change in electricity demand in the European Union, 2021-2025



Notes: On the left chart, other includes the combined effect of changes in electricity demand in households, services and other sectors, including increases from EVs, cooling, heat pumps (HP) and data centres in 2022, 2023, 2024 and 2025. On the right chart, these are shown separately. Values for 2025 are estimated.

Weather impact on electricity demand in the European Union in 2025 was notable. We estimate that, if weather conditions had been the same as in 2024, demand growth in 2025 would have been about 0.6%. Demand in the buildings sector was due primarily by higher space-heating requirements, as winter temperatures in 2025 were colder than in the previous year. Additional support came from increased cooling demand due to hotter weather in countries such as Spain and France – more than offsetting reduced cooling needs in other parts of the European Union. Similarly, lower year-on-year heating demand in Northern Europe was more than compensated for by increases elsewhere in the region.

Estimated year-on-year weather-related change in electricity consumption for heating and cooling in the European Union, 2025

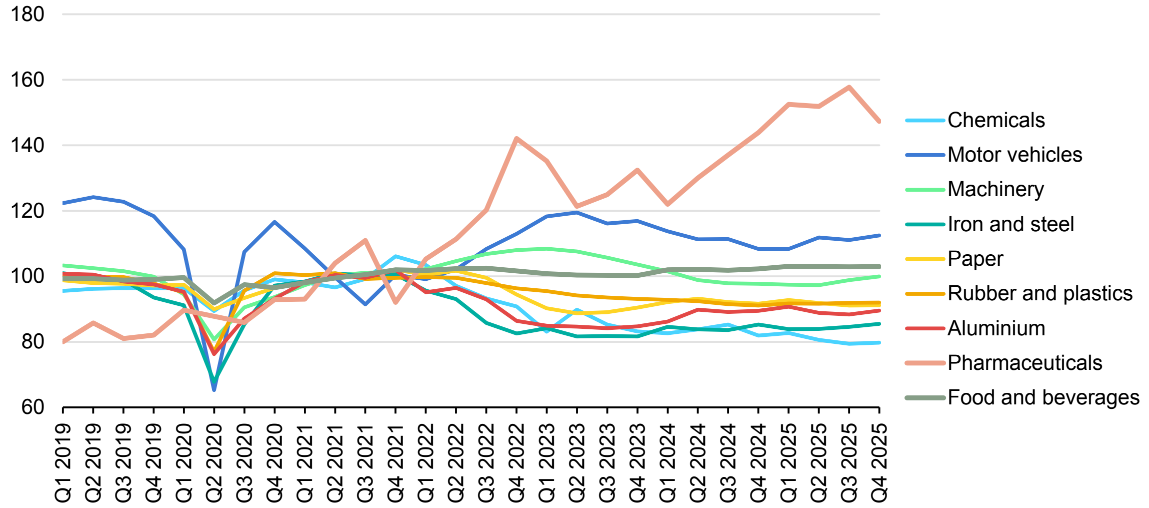


Notes: Southern Europe includes: Bulgaria, Croatia, Cyprus, Greece, Italy, Malta, Portugal and Romania. Central Europe includes: Austria, Belgium, Czechia, Germany, Hungary, Luxembourg, Netherlands, Poland, Slovak Republic and Slovenia. Northern Europe includes: Denmark, Estonia, Finland, Ireland, Latvia, Lithuania and Sweden. The joint effect for France and Spain is shown as a standalone group, as both countries exhibited comparable 2025 weather trends with respect to heating and cooling degree days.

Industrial electricity demand in the European Union is estimated to have remained relatively flat in 2025, after increasing slightly by close to 2% in 2024, after two consecutive 6% declines in 2022 and 2023 amid the energy crisis. The euro area manufacturing Purchasing Managers' Index (PMI) was, overall, around 5% y-o-y higher in the January-November period. Nevertheless, except in August, when it reached 50.7, the PMI remained below the expansion threshold for more than 40 months in a row. While production of primary metals (i.e. iron, steel, and aluminium) remained stable in 2025, output of chemicals was lower year-on-year. By contrast, the pharmaceutical sector has seen robust growth.

The chemical sector, in particular, remains under competitive pressure since the start of the energy crisis, amid weak demand and higher energy prices. According to CEFIC, the EU chemical sector has been operating at 9.5% below the 2014-2019 pre-crisis capacity. Likewise, the EU automotive sector is facing significant competitive pressure, with production of motor vehicles in 2025 down by around 10% compared to 2019. The EU commission put forward an action plan in March 2025 on the future of the automotive sector that proposes practical measures to secure a resilient and sustainable automotive industry while fostering greater innovation.

Production indices of selected industries in the European Union, 2019-2025



Notes: The data is seasonally and calendar adjusted, with data presented as an index with 2021=100. Data for 2025 includes data from January to November.
Source: IEA analysis based on data from Eurostat.

EV uptake in the European Union strengthened in 2025. In 2025, new car registrations rose by 1.8% y-o-y. Over the same period, BEV registrations increased by about 30% and plug-in hybrid electric vehicle (PHEV) registrations by around 33%. The market share of BEVs in new car registrations rose from less than 14% in 2024 to just over 17% in 2025. This trend coincided with the application of tighter European Union CO_2 emission standards for new cars and vans in 2025, marking the start of a new compliance phase for manufacturers. The European Union also introduced additional flexibility measures in how compliance with the 2025-2027 targets is assessed, allowing manufacturers to meet requirements on a multi-year average basis rather than strictly year by year.

In 2025, heat pump sales in the European Union showed signs of recovery. After declining in the first half of 2024, sales increased in the first half of 2025, rising by an average of 9% y-o-y across 13 European countries. Despite this improvement, sales remained below the record levels reached in 2022, when heat pump sales peaked in Europe. This recovery took place against a changing European Union policy backdrop, including the phase-out of public financial incentives for new stand-alone fossil fuel boilers from 1 January 2025, as required under the Revised Energy Performance of Buildings Directive.

Renewables share in total electricity generation is set to surpass the 50% mark in 2026

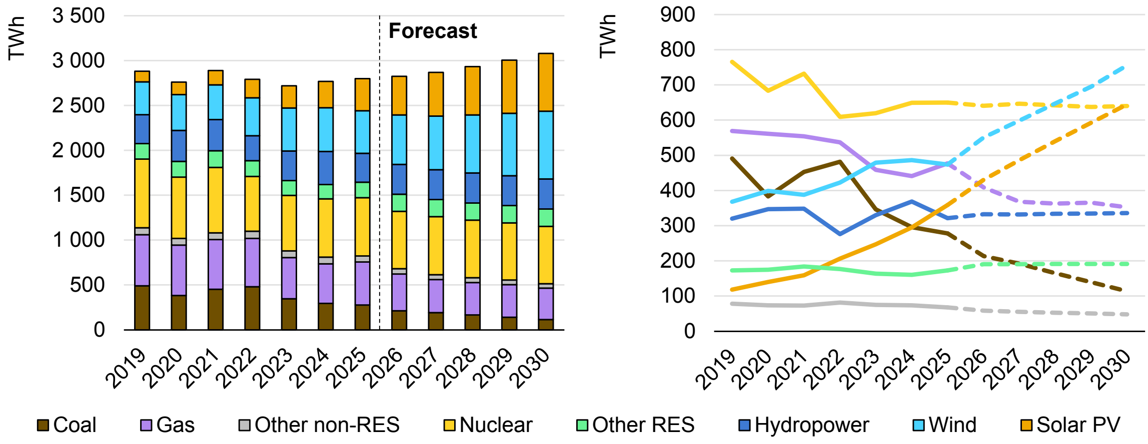
The European Union marked a milestone in 2025 as combined solar PV and wind generation surpassed fossil-fired generation. Notably, this occurred despite weather-driven declines in hydropower and wind generation resulting in robust fossil-fired output. Wind generation fell by around 2.5% y-o-y amid reduced wind speeds, while hydropower was down by about 13% due to lower rainfall. These declines contributed to higher gas burn in the power sector, which increased by just under 8.5%, and tempered the decline rate in coal-fired generation. EU coal-fired output was down by 6% compared with a strong 15% contraction in 2024.

Nuclear generation remained stable in 2025 amid stronger output in France, among many other countries, while Belgium retired the Tihange 1 and Doel 2 reactors in October and November, respectively. Slovakia's Mochovce nuclear plant's Unit 4 reactor (470 MW), which is currently under construction, is expected to become operational in 2026.

Solar PV generation grew strongly in 2025, up 22%, and overtook hydropower to become the second-largest source of renewable electricity in the European Union, behind only wind energy. As a result, total renewable electricity generation rose around 1% y-o-y.

Over our five-year forecast period, renewable electricity generation in the European Union is set to rise by an annual average growth rate of about 8%. In 2026, it will surpass all non-renewable generation combined. From end-2025 until end-2030, more than 400 GW of net renewable energy capacity is expected to be added, with 70% coming from solar PV, among which utility-scale and distributed assets will account for roughly equal shares. The share of renewables in total electricity generation is forecast to reach 63% in 2030, up from 48% in 2025. Similarly, the share of VRE (solar PV and wind) is expected to total 46% in 2030, up from 30% in 2025.

Electricity generation by source in the European Union, 2019-2030



Notes: RES = renewable energy sources. 'Other non-RES' includes oil, waste and other non-renewable sources. 'Other RES' includes geothermal, bioenergy, concentrated solar power (CSP), and ocean energy. Data for 2026-2030 are forecast values.

Given strong growth in renewables, we expect fossil fuel-fired generation in the European Union to contract through 2030, resulting in a near 45% drop in emissions from electricity generation at the end of the decade compared to 2025. Coal-fired generation is forecast to fall by an average 16% annually over the forecast period and natural gas by a more moderate 5.9%. Although electricity generation from gas is declining, gas-fired power plants will remain essential in providing supply-side flexibility to the system, particularly in response to seasonal fluctuations affecting weather-dependent renewables, such as during episodic wind droughts (e.g. *Dunkelflaute* events).

During the summer of 2025, Europe was markedly affected by heatwaves, which significantly intensified pressure on the European power grid. Overheated cables and thermal power plants, combined with increased electricity demand from mounting air conditioning use, tested power system resilience. The French distribution system operator, Enedis, attributed the cause of a power outage that hit Paris to extreme heat on 23 June 2025. France's nuclear power generation, which depends on river or seawater for cooling, was also impacted by the scorching heatwave, with 17 of its 18 plants undergoing either forced or planned reductions in output.

The 'Clean Industrial Deal' was launched in 2025 to bolster industrial competitiveness

The European Commission launched the Clean Industrial Deal in February 2025, which builds upon the previous European Green deal, to bolster the EU's industrial competitiveness while maintaining decarbonisation goals. Within this framework, funds of over EUR 100 billion will be mobilised to support EU-made clean manufacturing. At the same time, the Affordable Energy Action Plan was adopted to address cost pressures on energy-intensive sectors. Also, the Industrial Decarbonisation Accelerator Act was proposed at end-2025 aimed at speeding up technology deployment, with the name later changed to Industrial Accelerator Act, with "Decarbonisation" removed to cover a broader scope of sectors and technologies.

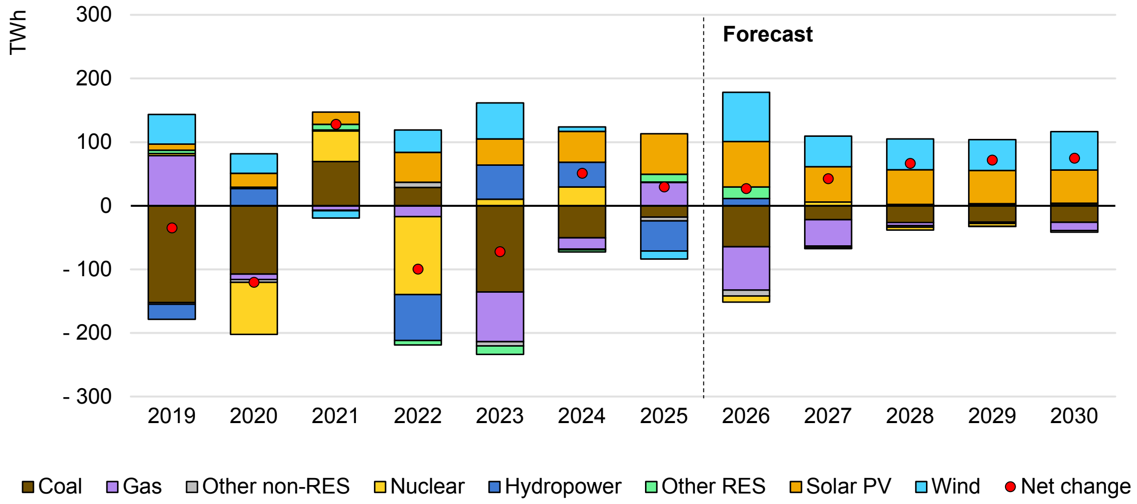
On 30 September 2025, the transition from hourly to 15-minute trading intervals on the day-ahead electricity markets was achieved. The change is expected to enhance market flexibility, better integrate variable renewable energies and more accurately reflect expected electricity generation and demand in the system.

In October 2025, the amended Regulation for the Simplifications for the Carbon Border Adjustment Mechanism (CBAM) was published. The main aspect of the package is the new exemption threshold of 50 tonnes for CBAM goods, where companies importing less than this volume annually are to be exempt from CBAM obligations.

The EU commission presented a new Nationally Determined Contribution (NDC) in November 2025 at COP30, with a commitment to reduce GHG emissions by 66.25% to 72.5% by 2035. Member States also agreed on a legally-binding 90% GHG emissions reduction by 2040.

The European Grids Package was launched in December 2025. It builds on the 2023 Grid Action Plan and forms part of the Competitiveness Compass and the Clean Industrial Deal. The purpose of this package is to help upgrade and expand electricity grids to enable rapid electrification and streamline permitting processes, which are critical for integrating renewables.

Year-on-year change in electricity generation in the European Union, 2019-2030



Notes: RES = renewable energy sources. 'Other non-RES' includes oil, waste and other non-renewable sources. 'Other RES' includes geothermal, bioenergy, concentrated solar power (CSP), and ocean energy. Data for 2026-2030 are forecast values.

Germany

Demand is forecast to grow faster through 2030 after a modest rise in 2025, while renewables maintain strong momentum

Germany's electricity demand grew at a moderate rate of around 0.5% in 2025 but is forecast to increase at a faster pace over the outlook period, with average annual growth of over 2.5% during 2026-2030. The stronger growth rates reflect higher demand from expanding electrification in the building and transport sectors, as well as an assumed gradual recovery in energy-intensive industries. On the supply side, renewables accounted for 57% of power generation, supported by a surge in solar PV output, which rose by 21% y-o-y. By contrast, wind power generation declined by 3.2% y-o-y due to weak wind conditions, while coal-fired output registered a decrease of more than 2%. Gas-fired generation grew by 4.5%.

Renewable generation is expected to maintain strong momentum in 2026-2030, averaging 10% growth per year, with solar PV and wind projected to increase by 13% and 11%, respectively. Coal- and gas-fired power generation are forecast to decline by an annual average of 21% and just under 8%, respectively. Germany is expected to remain a net importer of electricity throughout the outlook period.

Following the February 2025 federal election, Germany's new coalition government set ambitious energy policy targets in an agreement prioritising internationally competitive energy costs, aiming for a significant reduction in prices through a planned relief package. The plan also aims to align grid expansion with renewable deployment and promote system flexibility by removing regulatory barriers. To support these goals, the government commissioned a monitoring report (MR) to assess the status of the energy transition. The report highlights the government's targets and the cost of implementation, arguing that future planning must focus more strongly on system-wide cost-efficiency. The report states that, although solar PV deployment is on track to meet its 215 GW mark for 2030, wind targets are likely to be missed, and the 30 GW offshore wind goal is now projected to be met only in 2032 due to grid connection delays.

Rising grid congestion management reflects the gap between fast renewable deployment and slower grid expansion. As a result, controllable renewable plants located upstream of the congestion point are increasingly curtailed, and controllable generators downstream of this point are instructed to compensate for the reduced output upstream. Difficulties are also apparent in distributed solar PV integration, as over 40% of installed systems at 41 GW in 2024 cannot be controlled by grid or market operators, increasing system volatility and congestion management costs.

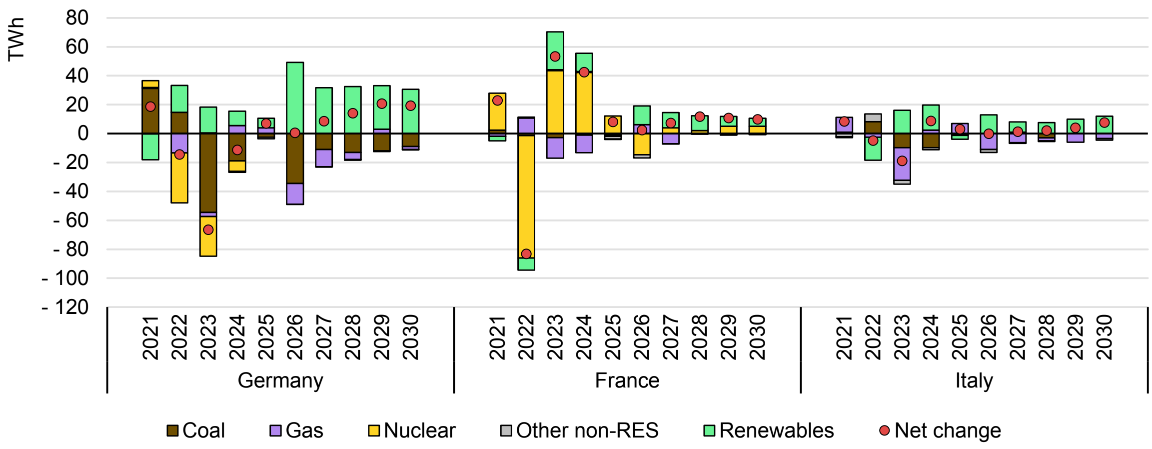
Costs have emerged as a central challenge to Germany's massive grid development plan for electricity. Transmission investment needs were increased from EUR 320 billion to EUR 440 billion by 2045, according to the latest grid development plan, as bottlenecks shift from planning to supply chains and construction. The MR also noted that investment needs for the distribution grid are likely underestimated, as the current projections (over EUR 235 billion by 2045) do not take into account the entire distribution network. Current planning practices continue to favour costly traditional reinforcement over digital, flexible solutions to manage load.

Based on partial 2025 data, Germany is on track to meet the 2025 target of connecting 20% of metering points with controllable devices like heat pumps and electric vehicles through the deployment of smart meters, a key enabler of digital and flexible solutions. Accelerating the roll-out further and adapting the regulatory frameworks to leverage these devices for grid management can reduce the need for physical grid expansion.

Security of supply is also a key focus in Germany. As part of its new power plant strategy, the government plans to hold tenders in 2026 for up to 12 GW of dispatchable capacity, of which 10 GW must be able to produce electricity over longer periods to ensure supply security, with plans for an introduction of a capacity market in later years. The targeted policy support recognises that market signals alone may not be enough to deliver the necessary investment in new power plants, while expanding secure capacity and enhancing flexibility remain essential to maintaining reliability standards.

Utility-scale batteries saw strong growth in Germany, with over 0.5 GW of large-scale storage (defined as ≥ 1 MW or ≥ 1 MWh) capacity installed in 2025. Large-scale systems now provide around 2.6 GW (4 GWh) of capacity, making them the second-biggest segment after residential storage. However, grid connection constraints are emerging as a key bottleneck to converting a long pipeline of projects into operational capacity. A recent survey by the industry association BDEW finds that grid operators are currently facing connection applications for more than 720 GW of large-scale batteries, of which at least 78 GW have already confirmed connection agreements. Transmission system operators (TSOs) caution that under the current first-come, first-served procedures, many projects could face multi-year delays unless grid planning and connection rules are reformed.

Year-on-year change in electricity generation in Germany, France, and Italy, 2021-2030



Notes: Other non-renewables include oil, waste and other non-renewable sources. Data for 2026-2030 are forecast values.

France

Electricity demand growth is met by robust output from the nuclear fleet and renewables through 2030

French power market fundamentals stabilised in 2025, as nuclear generation sustained its strong recovery since 2023. Electricity demand in France grew by about 1.2% y-o-y in 2025, up from growth of just under 1% in 2024, and marking a break with the 2018-2023 mostly bearish trend, when it declined by an average annual rate of 1.6%.

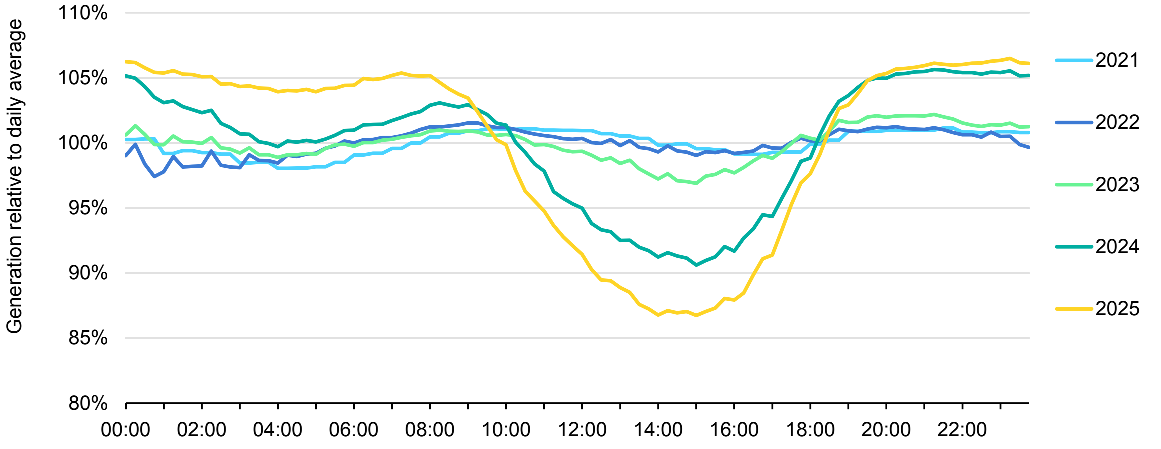
Electricity demand is now on track to post much stronger growth of an average annual rate of 2.0% from 2026 to 2030, with the pace accelerating towards the end of the outlook. The French TSO RTE updated its range of electricity demand projections in their Power System Outlook to 2035, published in December 2025, indicating an average annual growth rate of 0.9% to 2.5% through 2030.

We forecast that the additional demand over 2026-2030 will be met almost entirely by growth in wind and solar PV generation. Combined wind and solar PV output is expected to grow by almost 55% out to 2030, while nuclear generation is assumed to rise back to 2025 levels after a slight decline in 2026.

In 2025, hydroelectric output declined by 18%, compared with exceptionally robust growth of almost 27% the previous year. Record solar PV installations in 2024 helped drive growth in generation of 38% y-o-y in 2025. By contrast, wind power rose by a more moderate 6% y-o-y. Overall, total renewable production saw a slight decline of 0.3% y-o-y.

Nuclear generation grew by about 3% y-o-y, to its highest level since 2019, helped by the grid connection of France's newest reactor (Flamanville EPR) in late 2024. In addition, the impact of long-term improvements in outage management (both planned and unplanned) across the nuclear fleet supported further growth. At the same time, nuclear generation exhibited new levels of hourly variation in 2025 as it adapted to swings in the residual load in summer months. In July and August, hourly nuclear generation dipped by up to 13% from daily average levels, coinciding with periods of weaker demand and strong priority-dispatch renewables production – notably solar PV, which accounted for a record of up to 30% of afternoon-hour load in these months.

Quarter-hourly nuclear generation normalised to daily average, France, August 2025



Source: IEA analysis based on quarter-hourly electricity generation data from RTE (2025).

Despite an expected acceleration in renewables growth, reaching the country's 2030 targets remains uncertain. In the ongoing iteration of the Pluriannual Energy Programme (PPE3), initially expected in 2023 and still unpublished by the start of 2026, draft versions proposed technology-specific installed capacity targets for renewable energy. Meanwhile, alternative legislative proposals have included a technology-agnostic 200 TWh renewable electricity production target for 2030 (compared to about 150 TWh in 2025). Despite garnering Senate support, the bills had not yet passed both houses of parliament by the start of 2026.

Progress continued on the integration of renewables in the power system, notably through three regulatory evolutions in 2025. The first was the update of the hours corresponding to retail peak and off-peak pricing, intended to better orient price-informed consumption incentives to high-renewable production hours, particularly with the rise in solar PV generation. The roll-out of the updated pricing structure from November 2025 is expected to last through 2027. Second, following recommendations from the regulator, French lawmakers proposed and implemented adjustments to remuneration rules for renewable installations under contracts-for-difference or feed-in tariffs (under specific conditions), limiting their incentive to produce during negative price hours while also allowing flexibility in responding to such market conditions. Instead of forcing an immediate cut in generation as soon as prices turn negative, the new rules would allow for continued generation under specific situations of marginally negative prices, avoiding sharp drops in generation when only small balancing adjustments are needed. Third was the decision requiring all power generating assets above 10 MW, including renewables, to participate in the national balancing mechanism starting when in 2026, which aims to address a lack of sufficient downward balancing offers under a mechanism where only dispatchable resources were included.

Finally, France's Regulated Access to Incumbent Nuclear Electricity (ARENH) was phased out as expected on 1 January 2026, replaced by a new mechanism (le Versement Nucléaire Universel or VNU) to share revenues over an agreed level with the government for subsequent redistribution to consumers.

Italy

Dedicated auctions increase utility-scale battery storage as focus on flexibility intensifies

Electricity demand in Italy remained relatively flat in 2025, but there was a wide range of trends among the various power sources. Gas-fired generation posted the strongest gains at around 5.5%, while renewable generation fell by 2% due to a sharp decline in hydro output of about 21% and a reduction of wind generation of just under 3.5% amid weather effects. At the same time, solar PV generation posted strong growth by around 25%. Coal-fired output fell by almost 14%.

Electricity demand growth is expected to revert to an upward trend over 2026-2030, with annual average growth of about 2%, compared to an average decline of 0.4% in the 2018-2024 period. Renewable generation is forecast to increase much faster than the previous past five years, at an average annual rate of around 6.5% over the period, led by strong growth in solar PV capacity especially. By contrast, gas-fired generation is set to decline by 5% annually in the forecast, with its share dropping from 47% in 2025 to 34% in 2030. Despite the contraction, it will remain essential for balancing intermittent variable renewable energy sources.

Numerous developments took place in 2025 in relation to Italy's national TSO, Terna, on the wholesale markets. Terna's first Mechanism for the Procurement of Electrical Storage Capacity (MACSE) auction secured 10 GWh of lithium-ion storage capacity for Southern Italy and islands in September 2025. Capacity market auctions run by Terna awarded contracts for available capacity (CDP[2]) to ensure grid reliability and resource adequacy during stress periods. For the 2026 delivery year (auction held on 18 December 2024), 38.4 GW of national capacity was awarded, plus 4.4 GW from abroad. For 2027 (auction held on 26–27 February 2025), national capacity awarded rose slightly to 38.6 GW. For the 2027 derated capacity, 95% were BESS assets.

In addition, the Italian Regulatory Authority for Energy, Networks and Environment (ARERA) approved the Integrated Text of Electricity Dispatching Rules (TIDE), a comprehensive reform of Italy's dispatching framework which took effect on 1 January 2025. It consolidates national dispatching rules, introduces EU regulatory terminology, and aligns the country's market and grid procedures with

[2] CDP - Capacità Disponibile in Probabilità

the recent EU electricity market design reforms to facilitate cross-border market integration. TIDE supports the transformation of Italy's power system towards replacing PUN[3] with zonal pricing, 15-minute imbalance settlements, wider access for aggregations and small players, and new ancillary services and fees.

Terna's long-term infrastructure roadmap sets out grid modernisation priorities through 2034, emphasising capacity, efficiency, and decarbonisation. Terna presented a EUR 23 billion Grid Development Plan (2025-2034) in March 2025 that aims to resolve local congestion, improve grid capacity, streamline connection requests, and reinforce grid stability. Key projects include major infrastructure developments such as the Tyrrhenian Link, connecting Sicily, Sardinia, and mainland Italy; the Adriatic Link, designed to strengthen North-South energy flows; the Sardinia-Corsica-Tuscany (Sa.Co.I.3) connection, which will replace the Sa.Co.I.2 link; and a 600 MW capacity cross-border Italy-Tunisia undersea cable. With these projects, transport capacity would more than double from 16 GW to 39 GW, while cross-border flows would be increased by approximately 40%.

In 2025, there were also significant developments on renewables integration and end-use consumers. Italy transitioned new installations from net-metering to net-billing. Although this shift is expected to result in slower growth, the impact is considered positive overall as the objective is to promote self-consumption while preserving support mechanisms through net billing.

Italy made progress in transposing the EU Electricity Market Design Reform into national law, outlined in Directive (EU) 2024/1711, alongside other relevant measures bolstering flexibility. A draft legislative decree dated 10 October 2025 introduced integrated definitions for active customers, renewable energy communities (REC), and self-consumption.

Italy is formally committed to phasing out coal on the mainland by 2025, and on the island of Sardinia by 2028. Environmental permits for the last two coal generators on the mainland (at Civitavecchia and Brindisi Sud) expired at the end of 2025. The generators have not been run recently due to a lack of economic viability. However, decisions on whether to decommission the plants or maintain them in reserve remain under consideration.

[3] PUN (Prezzo Unico Nazionale) single national price

Spain

Strengthening system resilience amid rapid renewable deployment

Electricity demand grew by just over 3% in 2025, following growth of 2.3% in 2024, led by new industrial activity, electrification of industrial and residential heating, transport sectors, and rising tourism activity. Over the forecast period, green hydrogen production will also add to demand growth, albeit to a lesser extent, alongside other emerging technologies. Reflecting these trends, the Updated National Energy and Climate Plan (NECP) also foresees a structural shift towards electricity as the backbone of decarbonisation.

Gas-fired output rose by 20%, while renewable generation grew by around 1%, led by a sharp 12% rise in solar PV. By contrast, both wind and hydropower output declined by more than 5%. This follows a year in which power-sector emissions fell sharply and renewable generation reached record levels.

In the medium term, electricity demand is projected to grow at an average annual rate of just under 2% between 2026 and 2030, much higher than the 0.4% average recorded in the past decade. Demand will be supported by the continuation of the major demand trends in 2025. Renewable generation is forecast to maintain strong momentum, with average annual growth of over 8.5% during the outlook period. Solar PV and wind generation are projected to expand by around 13.5% and 8.5% per year, respectively, between 2026 and 2030. Spain remains a robust and diversified market for renewables, with record project pipelines.

After conversion of the Aboño Power Plant in northern Spain into a gas unit, coal has virtually disappeared from the electricity mix, accounting for around only 1% of generation in 2025. A small number of units remain available, including Alcúdia in Mallorca Island, mainly as a back-up to guarantee supply in the event of disruptions. Spain's coal phase-out is accompanied by support measures for affected regions under a dedicated Just Transition Strategy.

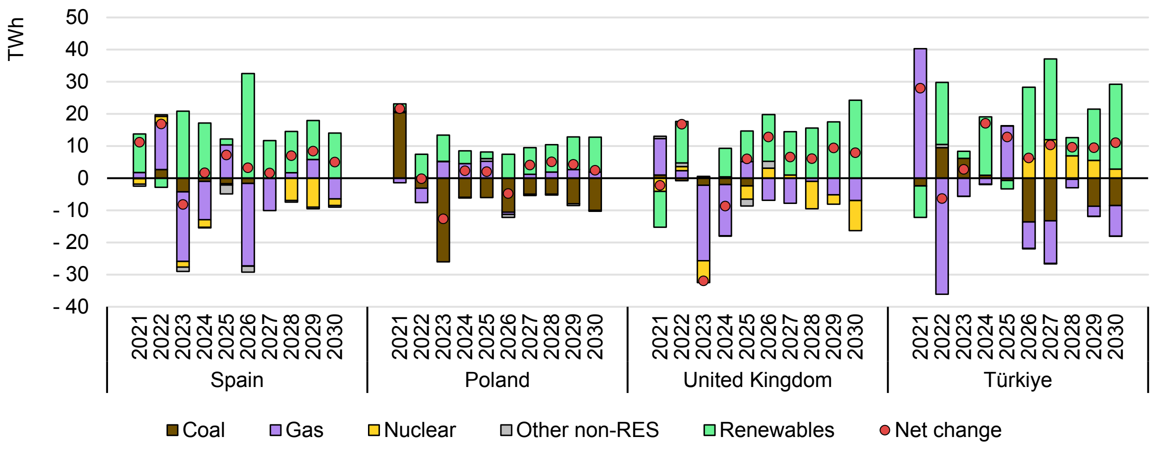
Renewable expansion continues, especially solar PV, which added 6.9 GW in 2025 to reach 39.4 GW (excluding self-consumption capacity), whereas wind capacity rose 1 GW to reach 33.2 GW in the same period. In addition, growth in self-consumption from distributed solar PV assets moved apace, and total installed capacity is estimated at 8.7 GW as of December 2025.

According to the current schedule of nuclear phase-out, Almaraz I will close by 2027, followed by Almaraz II in 2028 and Cofrentes and Ascó I in 2030. This will leave Spain's nuclear fleet at 3 GW by the end of our outlook period. However, a final decision has not been taken yet.

The Spanish electricity system received global attention after the blackout of the Spanish-Portuguese Peninsular system on 28 April 2025. The events have been described in the many reports published since then. A detailed overview can be found in a dedicated section in the Reliability chapter of our report. This blackout drew attention to issues that increasingly affect many power systems in the evolving Age of Electricity and reinforces key messages highlighted by the IEA, including the importance of investment in grids, electricity supply security and the challenges of renewable integration.

While progress on cross-border interconnections with France remains a strategic priority, the expansion of storage capacity to support the integration of variable renewables is gaining strong policy momentum. Spain has reinforced its framework for storage and system flexibility through a major call for new storage projects and a Royal Decree that streamlines hybridisation and permitting while strengthening system-operation rules, with a view to contribute to Spain's national target of reaching 22.5 GW of storage by 2030. The government has also initiated the public consultation of its 2030 transmission network development plan, which foresees around EUR 13.6 billion in investment to accommodate higher renewables and storage capacities, new interconnections and rising electricity demand.

Year-on-year change in electricity generation in Spain, Poland, United Kingdom, and Türkiye, 2021-2030



Notes: Other non-renewables include oil, waste and other non-renewable sources. Data for 2026-2030 are forecast values.

Poland

The share of renewables in generation reached 30% in 2025 and is set to surpass 50% by 2030

Electricity demand in Poland increased by more than 3% in 2025, supported by electrification and the continued recovery in economic growth. In June 2025, the country generated more electricity from renewables than from coal for the first time, with solar PV contributing the largest share. Coal-fired generation declined by around 6.5%, accounting for 52% of the power mix, while gas-fired generation grew by a significant 25% y-o-y. Renewables output rose by a more moderate 4.1%, tempered by reduced wind generation amid lower wind speeds.

Forecast electricity consumption is expected to grow at an average annual rate of 2.1% during the 2026-2030 period, triple the growth observed during 2018-2025. Renewable generation is projected to expand rapidly, averaging 13% on average per year through 2030, displacing coal as the primary source of energy on an annual basis in 2028, and accounting for the 53% of the electricity generation mix by the end of the decade. Gas-fired generation is anticipated to rise by an average annual rate of around 5% during 2026-2030, while coal-fired power is expected to fall by 11% annually over the same period. Poland is also on course to develop its first-ever nuclear power plant, with preparatory construction work in Choczewo started in October 2025. Using Westinghouse's AP1000 reactors, the three units will have a total capacity of around 3.7-3.75 GW, with a 2033 target for commercial operations. The European Commission granted Poland a derogation allowing power plants that exceed emissions standards, which are primarily coal-fired, to remain in the capacity market until the end of 2028.

Poland's Energy Regulatory Office (URE) held its first offshore wind auction in December 2025, awarding contracts to three projects with a combined capacity of 3.4 GW. The 25-year two-way CfDs are for Baltic East, Baltica 9 and Bałtyk 1. The successful completion of the awards advances the projects toward a final investment decision (FID) and eventual commissioning, joining the existing pool of 5.9 GW in the project pipeline. At the same time, the rapid growth of renewables has contributed to increasing curtailment levels, exceeding 1 TWh. At end-October 2025, the cumulative amount of curtailment increased by 82%, compared to the same period in 2024. Solar PV accounted for almost 70% of the curtailed output. Wind made up the remainder, reaching the highest monthly power curtailment on record.

Against this background, Poland is strengthening its grid flexibility. PGE, the state-owned and country's largest utility, announced plans to invest about USD 4.7 billion in 85 battery energy storage projects with a capacity of more than 17 GWh. Construction began in September 2025, which is one of the largest utility-scale battery projects in Europe, with a capacity of 263 MW (981 MWh). It is located adjacent to PGE's Żarnowiec Pumped Storage Power Plant. It is expected to be operational by Q2 2027 and enter the capacity market from 2029 under a 17-year contract. Poland also played a significant role in grid connectivity by providing a direct land bridge that facilitated the physical synchronisation between the Continental European electricity system and the Baltic states' grid systems, which has been in operation since February 2025. The new link via Poland enables Lithuania, Latvia, Estonia to strengthen their energy system resilience and integration with Continental Europe, allowing them to disconnect from Russia's electricity system.

Denmark

Renewables share in annual generation surpassed the 90% mark in 2025

In 2025, electricity demand in Denmark increased by about 4%, versus strong gains of around 6% seen in 2024. Coal-fired generation fell by 25%, including a three-month period without any coal-fired power for the first time. The share of renewables in the electricity mix reached 90%, despite almost 6% y-o-y lower wind generation due to poor wind conditions. By contrast, generation from solar PV rose by 17%. The share of VRE in annual generation stood at 66%, and in recent years Denmark has increasingly recorded hourly VRE shares exceeding 90%. The country's highly interconnected power system, with significant imports and exports, plays a key role in integrating large shares of VRE sources.

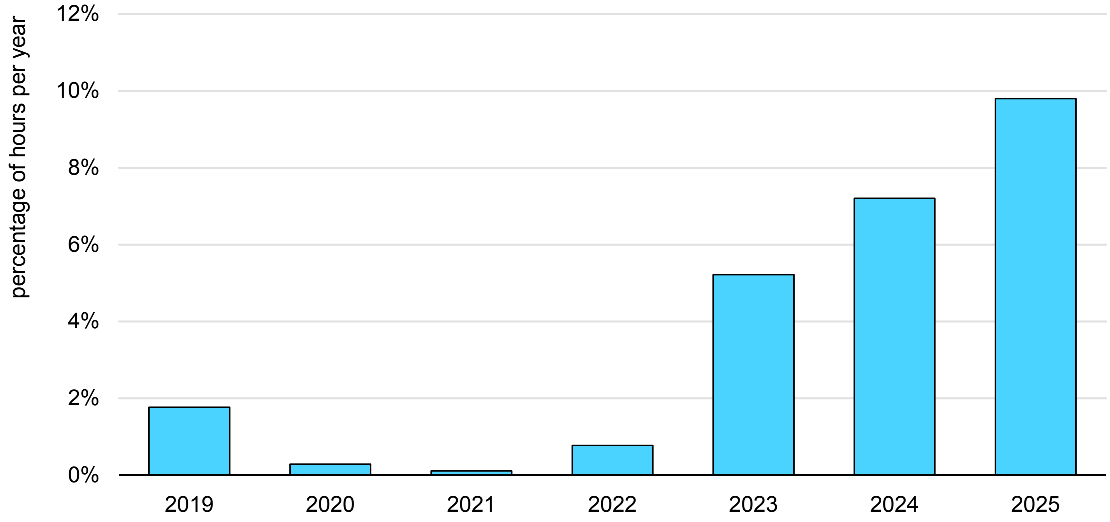
For the 2026-2030 period, electricity consumption is forecast to grow by an average of 3.6% per year, supported by the expansion of data centres as well as ongoing electrification of the heating and transport sectors. Coal-fired generation is expected to be phased out over the forecast period, in line with Denmark's 2028 target. Both wind and solar PV are expected to continue to post robust growth, averaging 5.6% and 16%, respectively, over the outlook period. The share of VRE in the electricity mix is forecast to reach around 78% by 2030.

Denmark plans to expand offshore wind capacity, with tenders opened for three new projects totalling at least 2.8 GW on 20 November 2025. The revamped tenders follow a political agreement from May 2025, market dialogue, and adjustments to the tender terms after the first 3 GW tranche of a 6 GW offshore wind tendering procedure launched in 2024 failed to attract any bidders. The government has offered subsidies to developers of up to DDK 55.2 billion (kroner) [USD 8.57 billion] over 20 years, with the bids determining the level of subsidy. The government updated the framework shortly before the tender opened to attract more bidders. While the total subsidy amount remains, adjustments were made to project timelines, capacity limits and subsidy distribution caps.

Denmark is considering lifting its 40-year old ban on nuclear power in order to improve its energy security, with the government investigating the potential benefits of new nuclear technologies, such as small modular reactors. Meanwhile, progress continues on the Bornholm Energy Island interconnector with Germany, supported by a grant of EUR 645.2 million from the European Climate, Infrastructure and Environment Executive Agency to help fund Denmark's side of the Hybrid Offshore Interconnector.

In March 2025, the Nordic transmission system operators (including Energinet) replaced the previous 60-minute manually activated mFRR balancing process with a 15-minute automatically activated mFRR market.

Percentage of hours per year in Denmark with a share of variable renewable energy in electricity generation greater than 90%, 2019-2025



Source: IEA analysis based on data from IEA Real-Time Electricity Tracker (2025).

Ireland

Wind and solar PV continue rising steadily to meet increasing demand, while gas-fired output remains robust

Electricity demand in Ireland continued its strong upward trajectory, increasing by more than 3% y-o-y in 2025. Growth was supported by ongoing electrification and the expansion of data centres, which accounted for around 22% of metered electricity consumption in 2024. Coal-fired generation officially ended in June 2025, following the conversion of the last remaining coal plant to oil. This converted unit will continue to operate as a reserve source during periods of tight system margins from 2025 to 2029. Natural gas-fired generation, the main source of dispatchable capacity, accounting for almost half of Ireland's electricity output over the past decade, decreased in 2025 by around 1.3% y-o-y. Its share in total generation fell from 49% in 2024 to 47% in 2025.

Total electricity generation remained broadly flat in 2025, while imports increased, maintaining their position as the third-largest source of electricity in Ireland's total electricity supply. Renewable electricity generation expanded by around 5% y-o-y, with wind posting growth of close to 4% while solar PV rose by about 50%. This increase in solar PV generation was supported by the expansion of installed capacity, which surpassed 2 GW for the first time in November 2025. Wind remains the leading source of renewable electricity, accounting for nearly 80% of VRE output in 2025.

From 2026-2030, electricity consumption is forecast to grow by an average of 3.6% per year. Gas-fired generation is projected to decline by around 7.5% annually, while renewable electricity output is expected to see strong yearly growth of 14% over the outlook period. Solar PV and wind are expected to drive growth, with average annual rates of about 44% and 11%, respectively. The combined share of wind and solar PV in generation is forecast to rise to 68% in 2030, up from 41% in 2025. Total renewables share is similarly expected to reach 73%, rising from 47%, over the same period.

In 2025, an increased focus was put on resilience and grid infrastructure following storm Éowyn in January, which caused widespread outages. The Greenlink interconnector between the United Kingdom and Ireland became operational in April, enhancing cross-border flexibility. Meanwhile, in July 2025, the government approved EUR 3.5 billion of investment in grid infrastructure and also reformed rules on electricity infrastructure by adopting a Private Wires Policy to allow private investors to build and own electricity lines in specific circumstances. The Commission for Regulation of Utilities also introduced the Electricity Connection Policy for Generation and System Services (ECP-GSS) in September 2024, shifting the grid-connection process from an annual basis to a twice yearly cycle. The first ECP-GSS batch, ECP GSS 1 for September 2025, required applicants to submit a pre-application notification and application fee to the relevant System Operator by 30 June 2025. Applicants completing this step were then able to submit a formal grid application up to the batch deadline of 30 September 2025.

United Kingdom

Share of wind and solar PV in generation is set to surpass 50% by 2030, rising from 37% in 2025

Following the definitive closure of the final remaining coal units in 2024, renewables supplied 53% of generation in 2025. Electricity consumption is estimated to have increased by around 0.5% in 2025. However, demand is forecast to rise steadily in our outlook, with growth at an average annual 1.8%, and reaching 3.6% by the end of the decade.

Over the forecast period, natural gas-fired generation is displaced by renewables, declining by 7% per year on average ,while renewables grow by just over 9% per year. Solar PV reaches 10% of the electricity generation mix in 2030, up from 7% in 2025, and wind's share increases to 45% from 30%. Nuclear generation drops off in 2028, reflecting current expected lifetimes.

The United Kingdom will preserve a single national bidding zone, pursuing "reformed national pricing" over a zonal or nodal market design. Enhancements such as stronger locational signals are pending publication in winter 2025/26. The Strategic Spatial Energy Plan, commissioned in 2024, increases locational signals for new capacity, defining generation capacity requirements for 17 zones across Great Britain. To meet deployment targets, such as 70 GW combined wind capacity by 2030, the CfD auction design was updated to allow the Department for Energy Security and Net Zero to view anonymised auction bids and decide how much capacity to award, with the option to increase the budget after reviewing the bids if a higher budget would provide value for money. To further de-risk while seeking to elicit broad participation, the CfD contract length was extended from 15 years to 20 years, and requirements were eased on planning consents for projects to be eligible. The first CfD auction under the CP2030 regime took place in late 2025. This capacity will be complemented by nuclear lifetime extensions as EDF announced that Heysham and Hartlepool power stations will remain operational for at least an additional year, until March 2028, following extensions in 2024.

Capacity market prices eased slightly but remained well above pre-2022 levels at GBP 60/kW in the 2025 long-term auction. Battery storage was the third-largest capacity category winning contracts in the 2025 long-term capacity auction, with over 6.2 GW and 17 GWh of nameplate capacity awarded, behind only gas (29.9 GW) and interconnectors (10.7 GW). The United Kingdom also remains hopeful of reaching an agreement with the EU to secure exemption from the CBAM that entered into force in 2026, before the UK equivalent in 2027.

The UK government set an ambition in 2024 to have up to 24 GW of installed nuclear capacity by 2050, including SMRs. In line with this target, in 2025 Rolls-Royce SMR Ltd was selected as the preferred bidder following a two-year competitive process. This is subject to final approvals by the government and contract signature. Following the selection, public consultation on the Rolls-Royce SMR design began in 2025, with a final investment decision expected in 2029 and first grid connection anticipated in the mid-2030s.

Türkiye

More than 33% of electricity generation is set to come from solar PV and wind by 2030 while demand grows robustly

Türkiye’s electricity demand grew by almost 3% y-o-y in 2025, supported by cooling needs during an unprecedented heatwave. July 2025 marked the hottest for the month on record, with temperatures reaching 50.5 Celsius in the southeast of the country, breaking the previous year's record. Demand is expected to increase at a solid pace, rising by an average of 2.6% per year between 2026 and 2030.

Coal-fired generation recorded a slight decline of around 0.5% in 2025, accounting for a 33% share of the electricity mix. By contrast, natural gas-fired generation increased by a sharp 24% y-o-y, with its share rising from 19% in 2024 to 23% in 2025. Both coal and gas are expected to decline from 2026 onwards, with average annual contractions of around 9% and 11%, respectively, through 2030.

Hydropower recorded the biggest decline among generation sources, falling by 23% y-o-y in 2025 due to severe droughts from the lowest rainfall in the last 52 years. Conversely, solar PV posted the strongest growth, increasing by around 44% y-o-y. The combined share of wind and solar PV in the electricity generation mix surpassed 20% in 2025 and is forecast to reach about 35% in 2030, five years ahead of the target set by the National Energy Plan (NEP) in 2022. Following the previous year’s completion of the initial phase development, Türkiye’s first nuclear power plant in Akkuyu, with 4.8 GW capacity, is nearing commissioning of its reactor scheduled in 2026. The NEP aims to increase the share of nuclear energy in power generation with new plants and SMRs.

To support the rapid growth in low-emissions generation, Türkiye passed the “Super Permit Law” (Law No. 7554) in July 2025. The regulation aims to shorten permitting, the approval process, and licensing procedures for wind and solar projects from the current average of around 48 months to 18-24 months. Türkiye is also focusing efforts on grid modernisation. In August 2025, the Transforming Power Transmission System Project (TPTS) was approved, aiming to modernise the national grid system for VRE integration. Supported by the World Bank, International Bank for Reconstruction and Development (IBRD) and Clean Technology Fund (CTF), the project will provide a total of USD 747.9 million in financing for Türkiye’s national grid expansion and upgrades, particularly for integrating increased capacities of wind and solar.

Ukraine

Ukraine's electricity system continues to evolve amid the most challenging winter since the Russian full-scale invasion

Ukraine's available generation capacity has fallen critically short of winter demand amid intensified Russian attacks in January 2026 and record-low temperatures, though uncertainty remains high**.** This winter, peak demand has reached 18 GW (against 16.5 GW during the 2024/25 heating season), while domestic generation capacity has been reduced to only 11.1 GW following systematic attacks on critical infrastructure. This projection reflects restoration efforts until the start of the heating season, including approximately 3 GW refurbished ahead of last winter, despite continued Russian strikes. Although winter demand levels remain uncertain due to population displacement and difficulties in predicting industrial activity levels, record-low temperatures ranging from -10 to -20 degrees Celsius at night have driven demand to critical levels. The country depends heavily on its three remaining operational nuclear power plants, which provide approximately half of the generation capacity. This creates vulnerability, as damage to transmission links or nearby substations can prevent these facilities from feeding the grid – a risk that has materialised with recent attacks on substations connecting nuclear power plants. The severity of the situation has prompted authorities to declare a state of emergency in the energy sector. Major cities, including capital Kyiv, have experienced both emergency and rolling blackouts, with millions of residents lacking access to heating and water for several days following massive attacks. In January alone, between 8-10 million people across Ukraine were without electricity and heating for several days after attacks, as combined heat and power plants around the country sustained damage.

Ukraine’s electricity security continues to benefit from interconnection with Europe following synchronisation with the continent’s grid in March 2022. This integration has proven vital, enabling imports during peak demand periods whilst allowing exports that help stabilise Ukraine’s grid and produce revenues when domestic generation is sufficient. In 2024, Ukraine imported a record 4 436 GWh of electricity – the highest level over the last decade – reflecting the extensive damage to its domestic generation capacity. In 2025, import levels declined as generation capacity gradually recovered and nuclear units returned from scheduled maintenance. Ukraine became a net electricity exporter between June and September, sending 635 GWh abroad in September alone – the highest monthly level since the war began. However, following intensified Russian attacks, this trend reversed sharply in autumn 2025, with Ukraine relying more heavily on imports since October to meet basic electricity needs amid the severe generation shortfall.

Ukraine's power sector has shifted toward decentralisation since the full-scale invasion began, with continued deployment of distributed energy and a significant expansion in grid-scale storage. Another major development came in September 2025 when DTEK and Fluence commissioned Ukraine's largest battery energy storage project: a 200 MW system with 400 MWh storage capacity distributed across six locations, capable of powering 600 000 homes for two hours and providing system services to Ukrenergo's grid. This project demonstrates how wartime necessity is accelerating the adoption of technologies that enhance grid resilience while also making the system harder to disable through targeted strikes. Wind energy is also advancing, with more than 700 MW of new capacity under development, including DTEK's approximately 400 MW Tyligulska Wind Farm expansion scheduled for late 2026.

Over the past 18 months, progress has advanced to expand cross-border capacity. Since December 2024, firm import capacity for Moldova and Ukraine combined has been set at 2.1 GW during the winter months and 1.7 GW in summer, whilst export capacity remains limited to 650 MW. Since June 2025, the available trade capacities are recalculated weekly, providing greater flexibility to respond to changing system conditions.

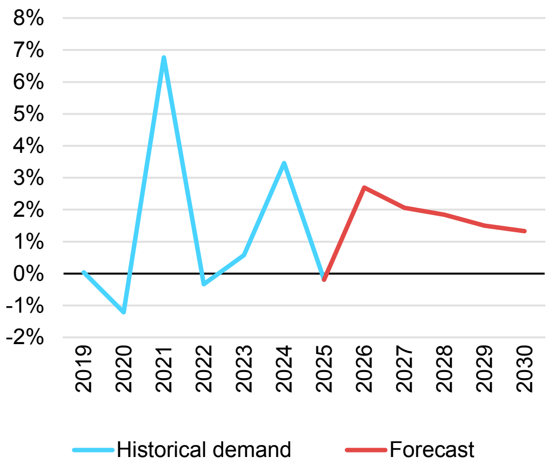
Ukraine advanced several key regulatory measures in 2025 to prepare for full integration with European electricity markets, despite wartime constraints. In July 2025, the Parliament passed Draft Law No.12087-d to implement EU legislation on energy market integration, which lays the groundwork for coupling Ukraine's day-ahead, intraday, and balancing markets with those of the European Union. The European Commission has indicated that full market coupling could be achieved by early 2027, provided Ukraine continues accelerating necessary reforms. Energy regulator NEURC approved rules for long-term capacity allocation at Ukraine's borders with Slovakia, Hungary and Romania, while also amending market rules to allow ancillary service providers greater operational flexibility.

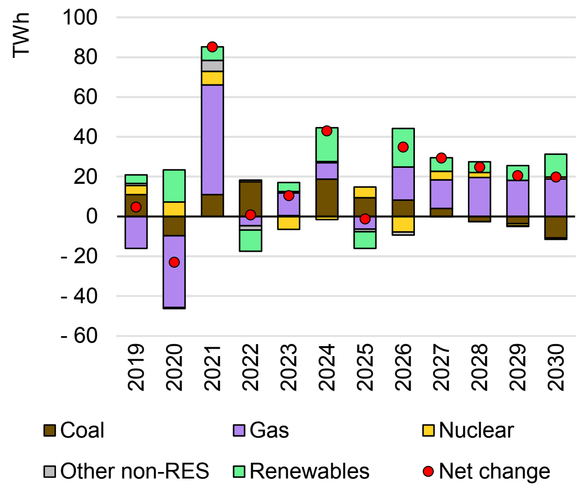
Eurasia

Russian electricity demand contracted, while overall regional growth was stable in 2025

Eurasia's electricity demand growth remained relatively flat in 2025, versus 3.5% growth in 2024, primarily due to Russia's weaker macroeconomic fundamentals and milder winter temperatures in the first quarter of the year. The region's demand growth is expected to rise to an average annual rate of just under 2% in the 2026-2030 outlook. Fossil-fired power generation will continue to dominate Eurasia's electricity mix, with a share of around 65% over the forecast period.

Year-on-year percent change in electricity demand (left) and year-on-year change in electricity generation (right), Eurasia, 2019-2030





Notes: Data for 2026-2030 are forecast values. Other non-renewable energy sources (RES) include oil, waste and other non-renewable sources.

Russia

Electricity demand is estimated to have declined by around 1% in 2025, but forecast to rise through 2030 at average 1.5% rate

The availability of energy-related data has deteriorated since Russia's full-scale invasion of Ukraine, making it challenging to assess the country's electricity consumption. Based on year-to-date data through November, Russia's electricity demand is estimated to have declined by around 1% in 2025, compared with the strong 3% growth the previous year. This reflects Russia's much weaker GDP growth of 0.6% in 2025 compared with 4.3% in 2024. In addition, unseasonably mild winter temperatures in Q1 2025 weighed on electricity consumption for space heating.

Russia's fossil fuel-fired thermal generation declined by 1% y-o-y in the first 11 months of 2025, while nuclear power output increased by 2.5% during the same period. By contrast, hydropower fell by 6% y-o-y, with the decline largely concentrated in Russia's Federal Siberian District (-9% y-o-y). Solar PV and wind power generation fell by 2.5% and by over 15% y-o-y, respectively. Russia's electricity imports increased by 7.2% y-o-y in Q1-Q3 2025, primarily supported by Kazakhstan. In October 2025, the Energy Minister said that Russia was facing 25 GW of supply capacity shortages across its regions because of outdated equipment, depleted resources and lack of imported components due to sanctions. The first unit of the Kursk-2 power plant (1 188 MW) was connected to the grid on 31 December 2025 at an initial output of 240 MW, with its capacity set to be gradually raised to full power as safety tests and commissioning procedures are completed.

Electricity demand growth is forecast to rise at an average annual rate of about 1.5% in 2026-2030. Nevertheless, there is significant uncertainty surrounding Russia's economic development, which can impact domestic electricity demand trends. The share of fossil-based thermal generation in the country's power mix is set to remain at around 64% on average over the forecast period. The build-up in wind and solar capacity remains slow.

Kazakhstan

Healthy macroeconomics drive stronger electricity demand growth in Kazakhstan

Kazakhstan's electricity consumption grew by a steep 4% in 2024 and is estimated to have increased by around 4% y-o-y in 2025, based on year-to-date data through October. A strong post-pandemic economic recovery, supported by sharply higher oil production, was the major catalyst behind robust growth in both years, with the country's GDP expanding by around 5% and 6.2%, respectively.

Kazakhstan's electricity demand is forecast to rise at an average of around 3% per year in 2026-2030, albeit at a slightly reduced rate as economic growth moderates, partly due to lower investment in the oil sector as well as expectations of a weaker oil price environment. The country's electricity mix remains largely unchanged over the outlook period, with coal accounting for nearly 60%, followed by gas-fired output at around 25% and renewables 15%.

Coal-based generation increased by an estimated 2.5% y-o-y in the first ten months of 2025, while gas-fired power expanded by around 15% y-o-y over the same period. Hydropower generation declined by 3.5% y-o-y in the first ten months of 2025. Domestic power generation was also supported by stronger wind output, which increased by nearly 19%in the first 10 months of 2025.

Other Eurasia

Combined electricity demand growth in other Eurasian markets was up by 3% in 2024 and first estimates indicate that it continued to expand at a similar pace in 2025. Electricity demand in Eurasia, excluding Kazakhstan and Russia, is forecast to increase at an average annual rate of 3.8% per year in the 2026-2030 period. This will be largely supported by the region's rising population and economic expansion.

In **Uzbekistan**, electricity generation rose by almost 5% in 2024, and is estimated to have grown by nearly 4% y-o-y in 2025. The country's electricity mix is largely dominated by gas-based generation, although the government is taking steps to diversify by developing renewable power generation capacities. Uzbekistan is planning to raise combined wind and solar power generation capacity to 20 GW by 2030.

In **Azerbaijan**, electricity demand rose by 3.8% in 2024 and is estimated to have increased by around 2% y-o-y in 2025. Fossil-fired thermal generation (largely gas-based) accounted for just over 85% of total electricity output during this period. Renewables power generation increased by 2% y-o-y.

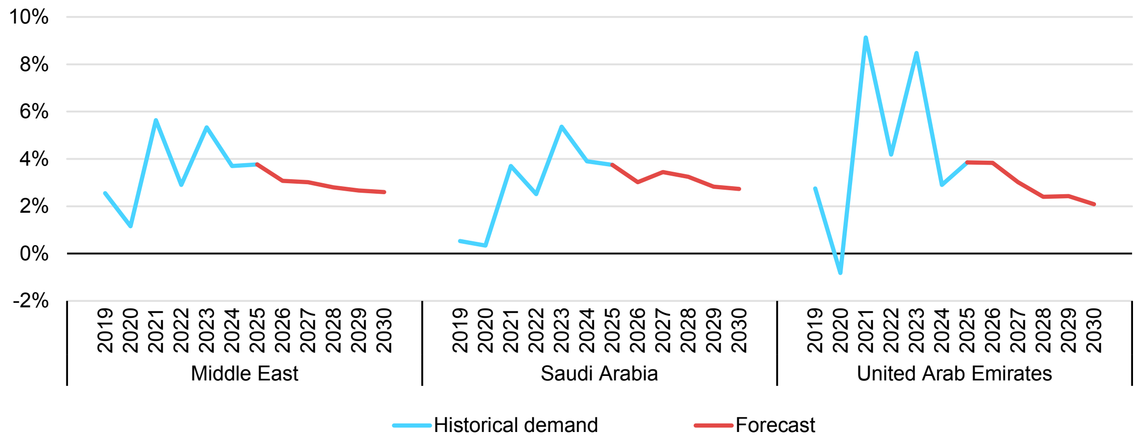
In **Turkmenistan**, electricity generation continued to expand, primarily supported by the country's large gas-fired power plant fleet. Turkmenistan is a significant exporter of electricity to neighbouring markets, including Afghanistan, Iran, Kyrgyzstan and Uzbekistan. The country started exporting electricity to Kyrgyzstan in August 2021 and deliveries for 2025 were expected to reach 1.7 TWh. In April 2025, the two countries agreed to extend the agreement for 2026. In January 2024, Turkmenistan agreed to supply 1.8 TWh to Afghanistan. The two countries are also considering the feasibility of the TAP-500 transmission project, with a planned capacity of 1 GW, but the proposal faces considerable political, security, and logistical challenges. An October 2022 agreement between Turkmenistan and Uzbekistan for electricity exports of a targeted 4 TWh/yr reportedly remains in effect, although actual yearly trade volumes have not been disclosed.

Middle East

Gas-fired generation rises rapidly while renewables post sharp gains

Following an increase of 3.7% in 2024, electricity demand in the Middle East rose slightly higher at 3.8% in 2025, underpinned by continued robust economic growth and rising cooling needs. We forecast growth to ease slightly from these higher level at an annual average rate of 2.8% through 2030. Saudi Arabia makes up around 31% of electricity consumption in the Middle East and is correspondingly set to account for almost one-third of the additional demand in the region. The United Arab Emirates (UAE) accounts for 12% of growth, Kuwait 9%, Qatar 5%, Israel 4%[1], and Oman with 3%.

Year-on-year percent change in electricity demand, Middle East, 2019-2030



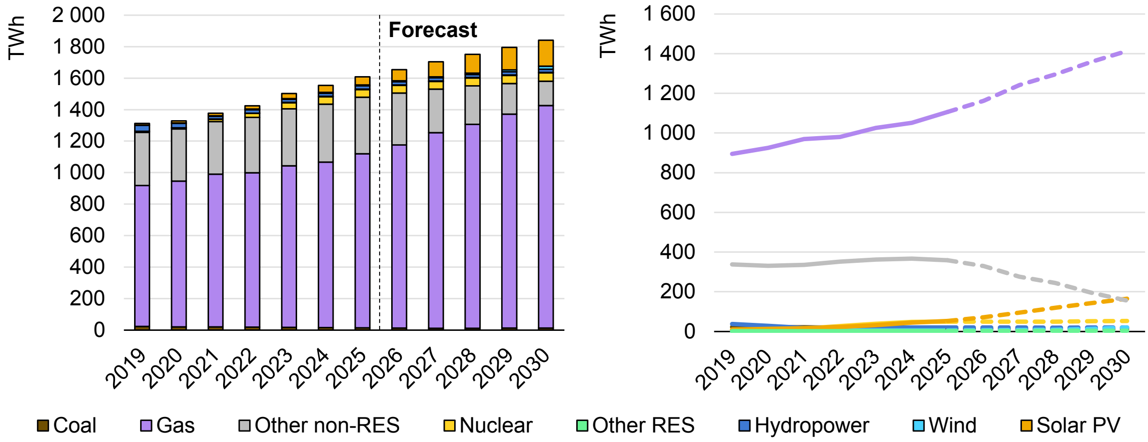
Notes: Data for 2026-2030 are forecast values.

Natural gas remains the dominant generation source in the region, with almost 70% share of the electricity mix. At the same time, strong momentum towards renewables, particularly solar PV, is supported by ambitious government targets and large-scale project pipelines. At the same time the switch from burning oil to natural gas in the power sector is set to accelerate, led by Saudi Arabia. As a result, gas-fired generation increases at an average annual rate of 5% through 2030, while oil-fired output is forecast to fall by about 15% per year over the same

[1] The statistical data for Israel are supplied by and under the responsibility of the relevant Israeli authorities. The use of such data by the OECD is without prejudice to the status of the Golan Heights, East Jerusalem and Israeli settlements in the West Bank under the terms of international law.

period. Solar PV generation in the Middle East is expected to surpass oil-fired power by 2030. In parallel with strong growth in solar PV, utility-scale battery deployment in the region is also gaining traction. With its abundant solar resources, multiple large-scale projects are underway in Saudi Arabia and the UAE. At the same time, in both countries, major investments in interconnections and grid expansion are ongoing.

Electricity generation by source in the Middle East, 2019-2030



Notes: RES = renewable energy sources. 'Other non-RES' includes oil, waste and other non-renewable sources. 'Other RES' includes geothermal, bioenergy, concentrated solar power (CSP), and ocean energy. Data for 2026-2030 are forecast values.

Saudi Arabia

Surging electricity demand met by rising natural gas and renewables, while oil burn plummets by 2030

Electricity demand in Saudi Arabia increased by an estimated 3.8% y-o-y in 2025. Growth is forecast to average 3.1% annually in 2026-2030, higher than the 2.8% average recorded over the 2018-2025 period. Managing demand growth is a priority for the government, with the Saudi Energy Efficiency Center (SEEC) leading efforts to implement Minimum Energy Performance Standards (MEPS) as part of broader efforts on the demand-side.

Gas-fired output will continue as the country's mainstay source of generation, but renewables will post the fastest growth by far, at a stellar annual average rate of 45% in 2026-2030. Power generation from solar PV doubled in 2025 and is expected to increase sixfold by 2030. The share of renewables in power generation is forecast to reach around 15% of total generation in 2030, up from only 3% in 2025. Solar PV is set to make up more than 85% of total renewable generation in 2030, with the rest almost exclusively wind power.

The Kingdom aims to reach a 130 GW of installed renewables capacity by the end of the decade. In February 2025, the Al Shuaibah 2 solar PV plant, with a total capacity of over 2 GW, started commercial operation. In August 2025, a consortium led by Saudi giant ACWA Power announced it plans to invest USD 8.3 billion to build 15 GW of solar and wind farms in the country. In September 2025, Saudi Arabia's Public Procurement Company (SPPC) opened Round 7 of solar and wind projects under the National Renewable Energy Program, with a request for quotation (RFQ) for 5.3 GW of new capacity. This tender includes four solar PV plants: Mawqaq (600 MW), Tathleeth (600 MW), South Al-Ula (500 MW) and Tabrjal 2 (1 400 MW). It also includes two wind projects, Bilghah (1 300 MW) and Shagran (900 MW). The RFQ invites developers to prequalify, adding 3.1 GW solar and 2.2 GW wind to project pipelines. At the same time, the country has also been exploring the development of nuclear energy.

Natural gas dominates the rapid expansion of Saudi Arabia's power system over the outlook period, with growth forecast to rise by an annual average of 9% between 2026 and 2030, more than double the rate of just over 4% recorded in 2018-2025. By 2030, natural gas will account for 80% of power generation in the country. Saudi Aramco's multi-decade Master Gas System (MGS) plan provides the foundation for phasing out oil of power generation and is pivotal to the company's plans to expand gas production by 60% by 2030. A major milestone was reached in early December 2025 with the start-up of the massive USD 100 billion Jafurah unconventional gas project, with current production of 450 million cubic feet per day (MMcf/d) ramping up to 2 billion cubic feet per day (Bcf/d) by 2030. Jafurah will primarily feed the country's domestic power grid, displacing crude oil currently burned in power plants. In March 2025, Siemens Energy was awarded a USD 1.6 billion project to provide technology for two gas-fired power plants in Saudi Arabia, which will add 3.6 GW to the grid. Together, with efficiency efforts and the deployment of non-oil power capacity, the share of oil in power generation is set to decline from 37% in 2025 to just 6% by 2030.

Separately, the Kingdom continues to advance work on regional interconnections. The Egypt-Saudi 3 GW high-voltage direct current (HVDC) power interconnection is currently undergoing inspection and trial runs, with the first phase of 1.5 GW expected to be fully operational in April 2026, followed by the second phase several months later. The long-planned project creates a power bridge that will enable a flexible electricity exchange during the differing peak load times – Egypt's summer and Saudi Arabia's winter – to optimise generation, reduce fuel consumption and strengthen grid reliability.

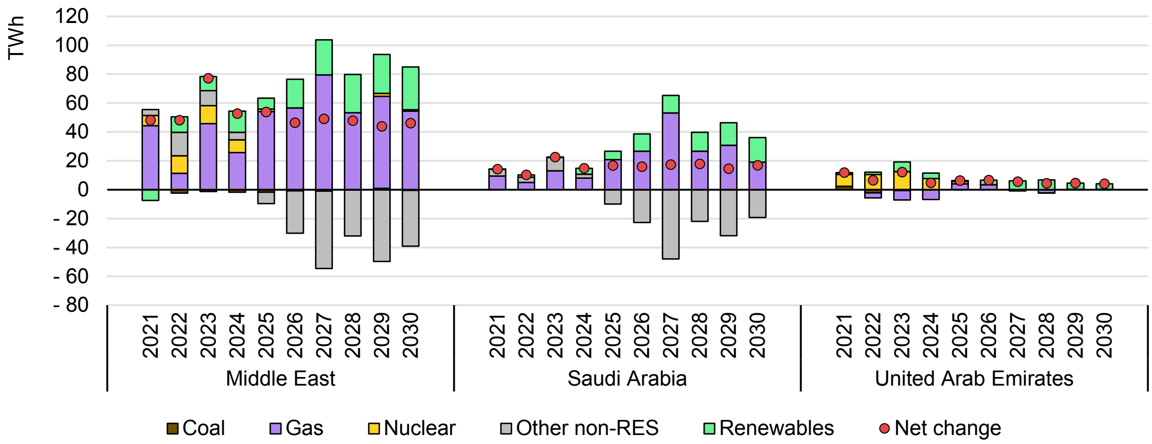
The GCC power grid expansion is also moving apace. The Abu Dhabi Fund for Development (ADFD) signed a financing agreement with the Gulf Cooperation Council Interconnection Authority (GCCIA) in June 2025 for the expansion of the power grid interconnection between the UAE and Saudi Arabia. The UAE-Saudi 400 kilovolt (kV) Al Silaa-Salwa project is expected to be completed by Q4 2027.

The expansion of the Gulf Electricity Interconnection System Project, which increases electricity export capacity from Saudi Arabia to Kuwait and Iraq, was nearing completion at end-2025, and expected to be operational in H1 2026. The project will lift transfer capacity to 3 GW between Saudi Arabia's Al-Fadhili converter station and Kuwait's Al Wafrah hub, and add a further connection to the Al-Faw station in southern Iraq with transmission capacity of 500 MW. At end-2025, Iraq's Ministry of Electricity and the GCCIA were still working to complete operational details and power purchase agreements (PPAs).

The Jordan-Saudi electricity interconnection project is moving forward with plans for an initial 500 MW, scalable to 1 GW. In April 2025, officials met to focus on accelerating key agreements on implementation, operations and commercial arrangements needed to begin project implementation. A Memorandum of Understanding (MoU) was inked in 2020 and plans call for commercial operations to start by end-2029.

Saudi Arabia's storage capacity deployment plans are also accelerating. In August 2025, the Saudi Electricity Company (SEC) awarded Hithium (with Alfanar) a 1 GW/4 GWh utility-scale BESS across Tabuk and Hail. This follows SEC's massive 2.5 GW/12.5 GWh storage system projects with China's BYD signed in February 2025, integrating solar and wind power across five sites into the national power system, helping to stabilise grids and meet peak energy demand periods. Installation of the five separate 500 MW/2 500 MWh energy storage systems is expected to be completed by Q1 2026. It is the world's largest grid-scale battery storage project, underscoring the country's commitment to scaling up its energy mix to reach 50% of renewables by 2030.

Year-on-year change in electricity generation, Middle East, 2021-2030



Notes: Other non-renewable energy sources (RES) include oil, waste and other non-renewable sources. Data for 2026-2030 are forecast values.

United Arab Emirates

Demand growth increasingly met by renewables through 2030, led by surging solar PV

Electricity demand in the UAE is estimated to have increased by about 4% y-o-y in 2025, in line with the average annual growth observed over the 2018-2024 period. In 2025, nuclear output was up by just over 4%, while both oil-fired and gas-fired power rose by about 3.5% each. Over 2026-2030, overall demand growth is projected to moderate to an average of about 3% annually. Oil and gas are set to remain largely unchanged, but renewables are expected to grow at a much faster pace of an average 18% per year over the forecast period, meeting all the additional demand.

Natural gas remains the backbone of the country's power generation, accounting for 65% of total power generation in 2025, though this share is expected to edge down to 58% by 2030. Nuclear is the second-largest source of power generation at around 24%, with its share projected to remain broadly stable through 2030. In September 2025, the Barakah nuclear power plant, with 5.6 GW of capacity, marked its first full-year of operation, with all four reactors online, and now supplies around one-quarter of the UAE's total electricity needs. Besides Iran, the UAE is the only Middle East country currently with an operational nuclear fleet.

Renewables are expected to be the fastest growing source of power generation, averaging annual increases of 18% over the 2026-2030 period. The shift towards sustainable energy is anchored in the country's national agendas, including the We the UAE 2031 vision, the UAE Energy Strategy 2050, and the UAE Net Zero 2050 Strategy, which all aim to accelerate renewables deployment. Renewables currently make up 11% of the UAE's power output and are estimated to reach 21% by the end of the decade, with solar PV providing the majority of generation.

Much of the UAE's renewables expansion is concentrated in the emirates of Abu Dhabi and Dubai. In Abu Dhabi, the Emirates Water and Electricity Company (EWEC) targets 60% of electricity demand to be met by low-carbon sources by 2035. The pipeline includes the 1.5 GW Al Ajban Solar PV park, slated to start commercial operations in Q3 2026. In October, Abu Dhabi broke ground on its USD 6 billion 24/7 solar and battery storage project, which will integrate 5.2 GW of solar PV capacity with a 19 GWh BESS to generate 1 GW of 24/7 uninterrupted clean power, with operations scheduled for 2027.

In Dubai, the Mohammed bin Rashid Solar Park is the emirate's flagship solar project with Phase 6 nearing completion. As of September 2025, more than 68% of the project was completed. The complex currently has 3.9 GW online, with about 0.8 GW under construction, and the Dubai Electricity and Water Authority

(DEWA) roadmap now targets 7.3 GW by 2030, up from the original 5 GW. In August, DEWA began trial operations at the 250 MW Hatta pumped storage plant, adding flexible, evening-peak capacity. With Hatta's local peak at about 39 MW, most electricity is exported to Dubai's grid.

The UAE is also strengthening regional interconnections. In September 2025, a new 400 kV Oman-UAE interconnection was announced, with an expected completion target of 2027. Separately, the GCCIA-UAE upgrade adds a 400 kV double-circuit line from Al Sila in the UAE to Salwa in Saudi Arabia, with substation works at Al Sila, Salwa and Gonan. This raises the UAE-Saudi transfer capacity from 2.4 GW to 3.5 GW, with completion due in Q4 2027.

Other Middle East

Kuwait

Kuwait's electricity demand has steadily increased in recent years, largely due to a combination of rapid population growth and rising cooling needs. In 2025, power demand is estimated to have risen by more than 1.5%. However, this demand growth has coincided with an ageing power generation fleet that has struggled to keep pace, resulting in periodic blackouts in 2024-2025, especially during the peak summer months.

Between 2025 and 2030, Kuwait's electricity demand is projected to increase by around 22%, led by a 46% rise in natural gas use for power generation. Over the same period, the use of oil and oil products in the generation mix is expected to decline by 24%.

This rapid expansion of gas-fired capacity is underpinned by recent and anticipated contract awards, including the Al-Zour North (Phases 2 and 3) independent water and power project (IWPP) for a total 2.7 GW signed with Saudi Arabia's ACWA Power and the Gulf Investment Corporation (GIC) in August 2025. Kuwait's Ministry of Electricity, Water and Renewable Energy is awaiting budget approval for Phase 4 of the Sabiya CCGT units, which will allow the tender to advance to Central Agency for Public Tenders (CAPT) for procurement. The contract award for the 900 MW power and water distillation plant was initially tipped for Q4 2025, but is now expected in early 2026. In addition, bidding for the 1.8 GW Khairan gas-fired power plant is underway, with an anticipated contract award in March 2026, with the project's planned completion in 2029. Meanwhile, tendering is underway for the first phase of the 3.6 GW Nuwaiseeb CCGT project, with construction expected to begin in 2027 and commercial operations for Phase 1 planned for 2028. These projects form part of the government's plans announced in October 2025 to add 14.05 GW of new power generation and 228 million gallons per day of freshwater desalination capacity by 2031.

While the government set an earlier target of achieving a 15% renewable share in the generation mix by 2030, progress has so far been limited and, as of 2025, Kuwait's renewable capacity stands at less than 0.1 GW. The Al Dibdibah and Al Shagaya solar projects – with a combined capacity of 1.6 GW – have made tentative progress toward approval in recent months. However, given the slow pace to date, substantial renewable capacity additions are expected to materialise only after 2030. As a result, renewables are projected to contribute just around 1% to Kuwait's electricity supply by the end of the forecast period.

Kuwait is in the early stages of developing power system flexibility, with 400-500 MW large-scale battery storage proposals under evaluation by the government. Current efforts continue to rely mainly on thermal capacity additions and emergency imports.

Oman

Oman's electricity demand increased by an estimated 2.7% in 2025 and is forecast to grow at a slightly lower average annual rate of just under 2.5% through the end of the decade. Natural gas will remain the dominant source of power generation, but its share is projected to decline from 94% in 2025 to around 75% by 2030. Over the same period, gas-fired electricity output is expected to fall by about 10%. Despite this anticipated decline, Oman plans to add 2.4 GW of CCGT capacity by 2029, potentially replacing older units.

Renewable generation is expected to expand more than fivefold, reaching 23% of total power supply by 2030. This represents remarkable growth, though still short of the government's 30% target for 2030. Solar PV is forecast to account for more than 60% of the increase in renewable generation, supported by the recent completion of the Manah I and II projects (adding a combined 1 GW) in early 2025 and an additional 1 GW of solar capacity planned across three sites (Ibri III, Sinaw, and Al Kamil). Wind power is expected to provide the remainder of renewable growth, with planned capacity additions of up to 1 GW by 2028. However, Oman's wind sector remains far less developed than solar, with only 50 MW (the Dhofar wind farm) operational as of 2025.

Oman is also developing its first utility-scale battery storage project, which will pair the 500 MW Ibri III solar PV plant with a 100 MWh storage system. In parallel, the Oman Electricity Transmission Company (OETC) plans to implement up to 51 network expansion and modernisation projects between 2025 and 2029, including continued work on the North-South Interconnect Project (Rabt) and two 400 kV transmission lines linking Oman with the UAE.

Qatar

Qatar's electricity consumption is estimated to have risen by 3.5% in 2025, fuelled by population growth, rising cooling demand, and increased industrial activity. Electricity demand growth is projected to expand by a similar average annual rate of 3.5% during the 2026-2030 period. Natural gas will remain the dominant source of power generation, with its share declining only slightly from around 97% in 2025 to 94% by 2030. In absolute terms, however, gas-fired generation is expected to increase by nearly 13% over the same period.

Gas-rich Qatar is also actively working to diversify its energy mix. In 2025, the country added 875 MW of solar capacity with the commissioning of the Ras Laffan and Mesaieed solar PV plants, bringing total renewable capacity to nearly 1.7 GW. Under the Qatar National Renewable Energy Strategy (QNRES), the government aims to expand renewable capacity to 4 GW by 2030, focusing primarily on solar PV. Nonetheless, the country's gas-fired generation fleet is also set for substantial expansion, with a 500 MW peaker plant at Ras Abu Fontas expected to begin operation in 2027 and a larger 2.4 GW CCGT plant in the same area scheduled to come online in 2028.

In 2025, Qatar's electricity and water utility (KAHRAMAA) accelerated the nationwide installation of smart meters, reaching full deployment. This initiative is creating the metering and communications backbone needed to enable commercial demand-response programmes and time-of-use pricing, both of which can enhance the economics of battery storage systems.

Israel

Israel's electricity demand is estimated to have risen by just over 3% y-o-y in 2025, marginally above the 2.9% observed over the past five years. Growth was bolstered by continued economic expansion and increased activity in the high-tech and service sectors.

Demand is projected to rise by around 2% per year on average through to 2030, supported by various factors, including the shift to electric vehicles, increased electrification of industrial processes, as well as the rise of power-intensive technologies such as AI and expansion of data centres.

In February 2025, the Israel Electricity Authority awarded contracts for 1.5 GW of high-voltage battery storage capacity across projects in three regions, marking a major step in grid flexibility and renewables integration. The tender results showed capacity tariffs ranging from USD 49.41 to USD 74.20 per kWh, underscoring the growing cost competitiveness and commercial maturity of utility-scale battery storage in the country. The same month, Enlight Renewable Energy Ltd. secured grid-connection rights for 300 MW of battery storage, supporting systems with an energy capacity ranging from 1 300 to 1 900 MWh. The project will operate under a regulated tariff for five years before transitioning to the merchant market, marking a key step toward market-based flexibility mechanisms.

In 2025, natural gas continued to dominate Israel's electricity generation mix, accounting for around 72% of total production, while coal contributed roughly 12% and renewable energy about 16%. The government's coal phase-out strategy advanced further in 2025, with measures targeting the closure or conversion of remaining coal-fired units, including the Orot Rabin Power Station, Israel's largest power plant, where several units are currently being converted to run on natural gas.

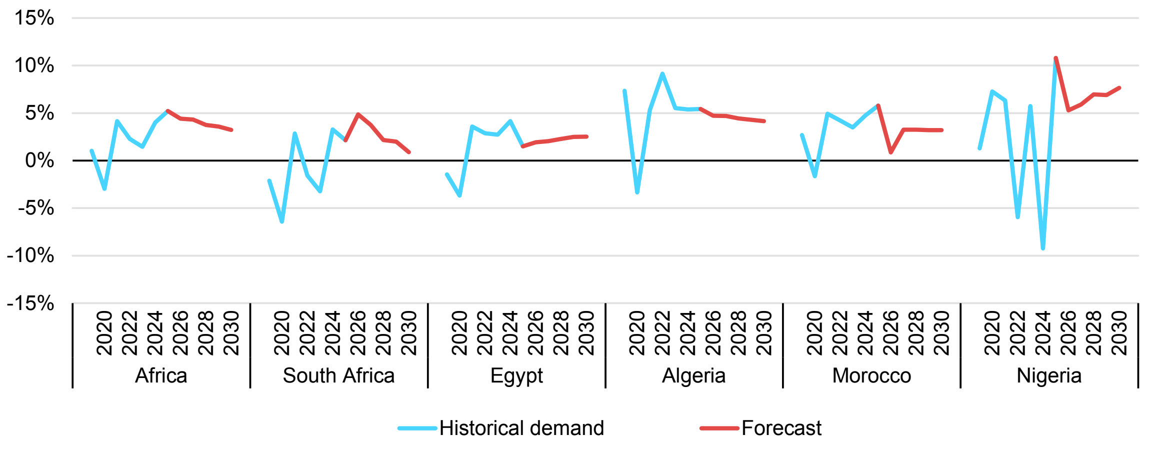
In early 2025, the Israeli Ministry of Energy launched a national campaign encouraging households to install rooftop solar panels and sell surplus electricity to the grid. The programme aims to expand distributed generation, increase consumer participation, and support Israel's clean energy and energy security goals, reinforcing the shift towards a more flexible and decentralised power system.

Africa

Growth supported by targeted efforts to expand electricity access

Electricity demand in Africa in 2025 rose 5.2%, versus 4% the previous year. The stronger pace was supported by markedly improved supply availabilities in South Africa, which makes up 25% of the region's consumption. Demand is forecast to rise on average around 3.9% annually in 2026-2030, with overall growth on the continent boosted by an expanding population, urbanisation, industrial activity, and targeted efforts to improve electricity access. Notably, countries like Kenya and Senegal are making significant progress towards universal electricity access, with the former aiming for full coverage by 2030 and the latter by 2029. Nigeria continues to expand access, particularly through off-grid and distributed solar solutions. However, challenges remain in matching demand growth with timely capacity additions and infrastructure upgrades, as evidenced by continued periodic supply constraints and grid bottlenecks in countries such as Nigeria and Kenya.

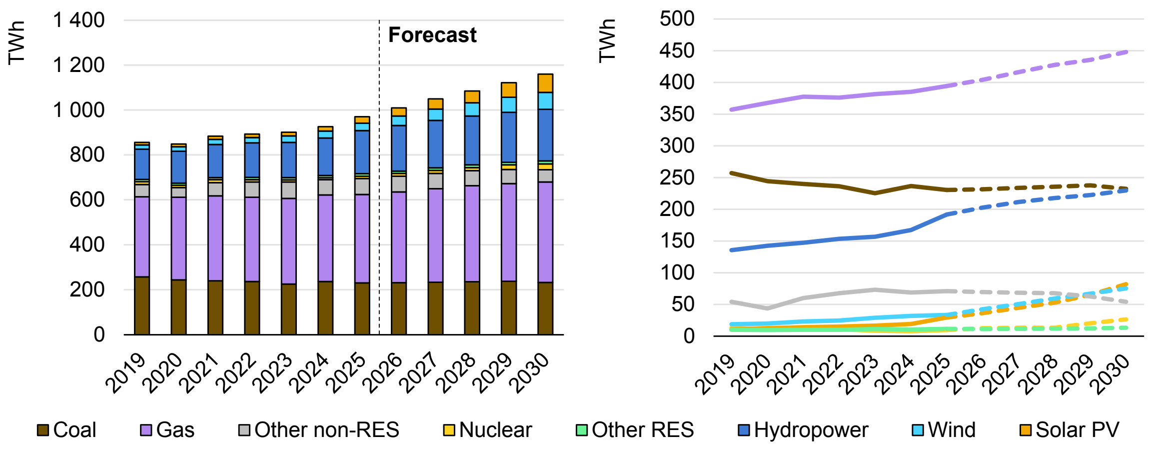
Year-on-year percent change in electricity demand, Africa, 2019-2030



Notes: Data for 2025 are preliminary. Data for 2026-2030 are forecast values. The plot starts from 2019, whereas the x-axis labels are shown only for the even years due to limited space.

Natural gas remains the dominant fuel in Africa, up by 2.3% y-o-y, with a share of over 40% in the generation mix in 2025. Gas-fired power is projected to grow at a similar pace of 2.6% on average in our 2026-2030 forecast period. By contrast, coal-fired output is expected to remain stable through 2030, assuming availability levels in South Africa remain close to those observed in 2025. Hydropower, wind and solar PV generation are all expected to see strong growth. By contrast, oil-fired output is forecast to fall by almost 5.5% on average per year to 2030 and eventually will be surpassed by both solar PV and wind generation over the forecast period. Multiple solar PV projects with co-located utility-scale battery storage projects are taking shape across the continent. At the same time, nuclear energy is also forecast to rise through 2030. Towards the end of the decade, Egypt is expected become the second country in Africa with nuclear power generation, after South Africa, with the first unit of the El Dabaa nuclear power plant scheduled to enter operation.

Electricity generation by source in Africa, 2019-2030



IEA. CC BY 4.0.

Notes: RES = renewable energy sources. ‘Other non-RES’ includes oil, waste and other non-renewable sources. ‘Other RES’ includes geothermal, bioenergy, concentrated solar power (CSP), and ocean energy. Data for 2026-2030 are forecast values.

South Africa

Load shedding sharply declined in 2025, with a significant improvement in system reliability

Electricity consumption in South Africa is estimated to have increased by just over 2% y-o-y in 2025, based on data through November. Despite high demand growth, South Africa’s power system remained stable and reliable through the year. From April to October, electricity supply was maintained over 98% of the time. The country experienced only 749 GWh of load shedding from January to June 2025, compared to 4 126 GWh in 2024 – an 82% reduction. Between 1 April and 24 October 2025, South Africa went 161 consecutive days without load shedding.

Eskom’s Summer Outlook Briefing 2025/26 (September 2025-March 2026) forecasts continued stability, citing sustained gains in generation performance and operational discipline under the ongoing implementation of the Generation Recovery Plan (GRP). Launched in April 2023, the GRP has a broad remit to produce power more reliably via the Energy Availability Factor (EAF), which measures the percentage of Eskom's fleet that was available to produce electricity. The GRP focuses on a range of technical improvements, including implementing extensive maintenance work to enhance grid stability, reducing load shedding, increasing operational efficiencies, and repairing and refurbishing coal-fired power stations. These improvements also reflect broader system dynamics, notably the rapid expansion of behind-the-meter solar PV and utility-scale renewables, alongside lower peak demand, which reduced system stress.

Performance improvements across Eskom's coal fleet have also supported the recovery in stable electricity supply. As of late 2025, 57% of Eskom's fourteen coal-fired power stations are operating at an EAF above 70%, including three exceeding 90%, while another four are above 60%, reflecting the growing stability of the fleet under the Generation Recovery Plan. Eskom's coal fleet recorded an average EAF of around 62% in 2025, based on calendar year-to-date performance through early December, up from 59.8%, indicating an improvement in overall fleet reliability. This progress was further reinforced by the commercial commissioning of the Kusile Unit 6 in September 2025, which marked the completion of Eskom's long-running New-Build Programme. Together with Medupi, the two supercritical plants now provide up to 9.6 GW of baseload capacity. The addition of Kusile's new unit also contributes to Eskom's EAF metrics, helping sustain the upward trend in overall fleet performance.

South Africa's generation recovery gained further momentum in late 2025 after the full return of the Koeberg nuclear power plant, providing a stable source of low-emissions generation alongside improving coal fleet performance. With both units now operational, Koeberg is set to deliver over 1.86 GW, equivalent to around 5% of Eskom's total generation capacity, helping to sustain system reliability.

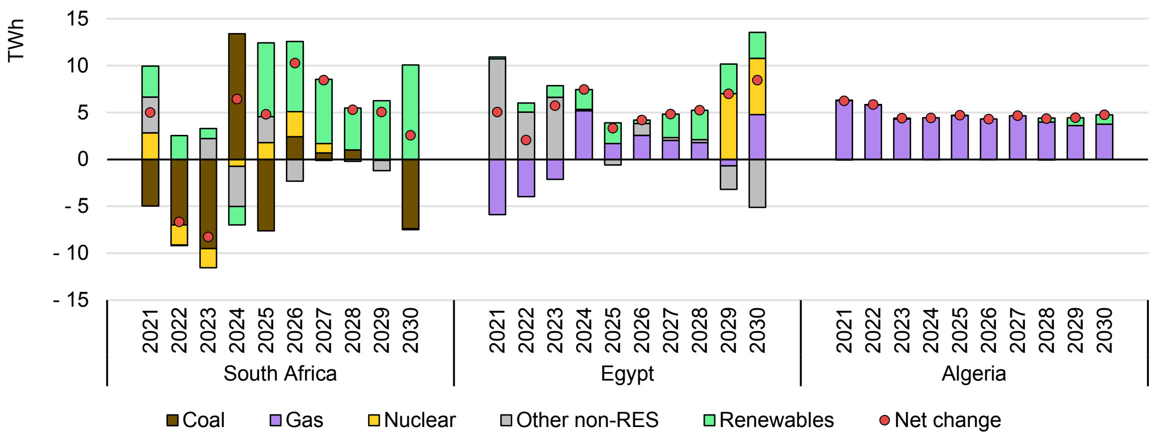
The restoration of Koeberg's full capacity, alongside improved availability across the thermal fleet, strengthens the implementation of Eskom's Generation Recovery Plan and aligns with the Integrated Resource Plan 2025, which identifies nuclear power as a clean, reliable and cost-effective component of South Africa's long-term energy mix. Eskom is also advancing demand-side and distribution reforms to eliminate "load reduction" measures by 2027, including installing 577 000 smart meters by 2026, expanding access to free basic electricity, and deploying distributed energy resources in high-risk or underserved areas.

On 11 March 2025, the National Energy Regulator of South Africa (NERSA) approved Eskom's tariff increases of 12.7% for direct customers (effective 1 April 2025) and 11.3% for municipalities (effective 1 July 2025). The reforms eliminated 'Inclining Block Tariffs' for residential customers, and introduced a single flat rate per kWh, as well as consolidated ten municipal tariffs into three simplified categories.

Eskom achieved a major financial turnaround in 2025, returning to profitability for the first time in eight years. The company reported an after-tax profit of ZAR 16 billion (South Africa rand), [USD 927.24 million], reversing the previous year's significant loss. This improvement was supported by a stronger operational performance, a higher average electricity tariff, lower primary energy costs, and government debt relief that reduced debt servicing costs. Reliability gains across the coal fleet limited the need for costly diesel-fired generation, leading to substantial fuel savings and a healthier earnings margin. The resulting surplus is planned towards investment in critical infrastructure upgrades.

In March 2025, the government approved the South African Renewable Energy Masterplan (SAREM), which targets up to 5 GW per year of new renewable generation and expanded battery storage to meet demand growth expected to nearly double by 2050. The plan's strategic priorities include system readiness, domestic clean-tech value chains, inclusive industry transformation, and skills development, as well as green hydrogen integration (aiming for a 5% blended-fuel share in aviation and maritime by 2030).

Year-on-year change in electricity generation in South Africa, Egypt, and Algeria, 2021-2030



Notes: Other non-renewable energy sources (RES) include oil, waste and other non-renewable sources. Data for 2026-2030 are forecast values.

Egypt

The dominant role of natural gas in power generation is set to continue through 2030

Egypt's electricity demand grew by an estimated 1.5% y-o-y in 2025, similar to the average growth rate observed over the past five years. Over the medium term, demand is expected to increase at a higher pace, averaging around 2.3% annually through to 2030, reflecting rising industrial activity, population growth, and higher cooling needs.

Natural gas accounted for about 75% of Egypt's electricity generation in 2025, while solar PV and wind together supplied around 7%. By 2030, the share of gas is projected to decline modestly to about 71%, while renewables are anticipated to rise to roughly 17%, assuming timely completion of planned solar PV and wind capacity additions.

Construction of the Egypt's first nuclear power plant at El Dabaa is progressing on schedule. The facility will comprise four Generation III+ VVER-1200 reactors with a total capacity of 4.8 GW. Work on Unit 1 began in July 2022, and in late 2025 a major milestone was reached when its reactor pressure vessel was installed. Grid connection is planned to begin in 2029, with all four units expected to be online by 2032. Once fully operational, El Dabaa could supply up to 10% of Egypt's electricity, reducing reliance on gas and supporting the government's target of 42% low-carbon energy by 2030.

New cross-border interconnections with Saudi Arabia, Sudan, Libya, and Jordan are advancing and expected to increase regional trade potential and enhance grid stability. At the same time, demand-side measures remain at an early stage, with the government continuing operational conservation measures such as curbing public lighting and limiting air conditioning to manage summer peaks.

Egypt aims to expand storage deployment and advance its smart meter roll-out, supported by regulatory updates. These measures are expected to enhance system flexibility and facilitate higher renewable penetration by 2030. In 2025, the country achieved a significant goal with the commissioning of its first utility-scale battery energy storage system, a 150 MW/300 MWh installation at a 500 MW solar PV plant in Aswan. In addition, a 1 GW solar PV plant and 100 MW/200 MWh of battery storage was launched in Nagaa Hammadi. These projects represent the first large-scale integration of battery storage into renewable power purchase agreements in Egypt and provide new intra-day flexibility that will enable solar generation to be shifted towards evening demand peaks.

Algeria

Electricity demand is set to sharply increase to 2030, met by growing natural gas-fired generation

Algeria's electricity demand is estimated to have risen by a sharp 5.4% in 2025, as extreme heatwaves sparked surging air conditioner use for cooling. Sonelgaz reported a new peak in electricity demand of 20 628 MW on 23 July amid a scorching hot summer. Demand is expected to increase at an average 4.5% annually through to 2030, supported by economic growth, rising cooling demand and continued population expansion.

Algeria’s power generation is almost entirely gas-fired, accounting for 99% of the electricity mix, with solar contributing very modestly. We forecast gas-fired generation to increase at an average annual rate of over 3.6% in 2026-2030. Algeria is accelerating the deployment of natural gas-fired capacity to meet rising demand while also weighing the impact on its gas export commitments. Algeria invested USD 1.2 billion to strengthen the grid ahead of the summer peak demand period. The country also continued exporting electricity to neighbouring Tunisia, which amounted to 3.1 TWh in 2025, almost 14% of the country’s annual power supply.

During our forecast period, solar PV output increases only modestly, with its share in generation rising from less than 1% in 2025 to just over 2% in 2030. While the country aims to increase the use of renewables, and set a goal of 15 GW installed capacity by 2035, tender delays have slowed progress on deployment and the coming years will be crucial to assess the country's capacity to meet its targets.

Morocco

Expanding renewables are set to meet all additional electricity demand out to 2030

Electricity demand in Morocco is estimated to have grown by nearly 6% in 2025, well above the annual average of 3.1% recorded between 2018 and 2024. Demand growth through 2030 is forecast at 2.8% per year.

The share of renewables in electricity generation was 26% in 2025. However, coal-fired power generation remains the dominant source, with a share of 58%, though this is projected to decline to 52% by 2030, while renewables rise to 34%. Renewables posted growth of almost 6.5% in 2025, and coal-fired generation rose by 5%. Oil-fired generation fell by more than 2% while gas-fired generation increased by a sharp 12%. Growth in renewables is projected to average just over 8.5% per year and coal is expected to maintain a flat trajectory through the end of the decade. Solar PV had a noticeable uptick in 2025, with output doubling, although this expansion was from a relatively low base. Solar PV generation is expected to average annual growth of about 31% in the 2026-2030 outlook period.

Morocco's 2021 NDC set a target of 52% for installed renewables electricity capacity by 2030. The 2025 update raises these ambitions, with plans to triple its renewable capacity to more than 15 GW by 2030, with a stronger focus on storage, grid reinforcement and regional interconnections. It also sets a coal phase-out date of 2040 that is conditional on international support.

The government advanced its renewables pipeline, with the Moroccan Agency for Sustainable Energy awarding the Noor Midelt II and III contract to Saudi Arabia's ACWA Power in August 2025. The project will have a combined 800 MW of solar capacity and about 1 200 MWh of battery storage. Morocco is also planning to develop a 1 600 MWh battery storage project in the northwest of the country to support power supply to the port city of Kenitra. Pumped storage remains a priority for Morocco, with the planned 300-400 MW El Menzel pumped-storage hydropower (PSH) project progressing through procurement to add long-duration flexibility. The project is slated to start commercial operation by 2028. On the thermal side, the National Office of Electricity and Drinking Water (ONEE) is preparing tenders for three new gas-fired power stations with a total capacity of between 300 MW and 450 MW in Ain Beni Mathar, Kenitra, and Mohammedia. All the plants are expected to be commissioned by mid-2026. There are also plans to scale up seawater desalination to bolster water security, a move that will contribute to rising electricity demand. The country currently operates 17 plants, has four more under construction and plans nine additional facilities, with almost all new plants powered by renewable energy. The country is aiming for total production of about 1.7 billion cubic metres per year (bcm/yr) by 2030.

In line with the three new electricity decrees announced in 2024, Morocco moved from rulemaking to implementation in 2025. The ministry issued the first Energy Service Company (ESCO) authorisation and published the official register in order to improve energy audits. ONEE advanced the smart bidirectional-metering roll-out under the World Bank programme, Clean and Efficient Energy Project, while a new smart meter production line opened in Fez in February to support local supply.

Morocco is also heavily involved in developing its interconnections. During the Iberian blackout on 28 April 2025, the Moroccan utility ONEE provided support during the restoration process by ensuring the supply of electricity to Spain's grid through the Morocco-Spain interconnection via Fardioua to Tarifa.

Nigeria

Solar PV on a sharp upward trajectory as demand returns to growth

Electricity access in Nigeria has expanded steadily over the past decade, up from 56% in 2014 to 71% in 2024. Yet, access remains uneven, with grid connection reaching nearly 96% of residents in urban areas, compared to only 41% in rural regions. These figures however exclude Nigeria's substantial and rapidly growing off-grid sector. According to the Energy Compact released in January 2025, the country aims to accelerate its annual pace of electricity access growth from 4% to 9% between 2024 and 2030. Electricity demand rebounded by a sharp 10.8% in 2025, following a contraction of about 9% the previous year, and we forecast continued strong growth of around 6.5% annually between 2026 and 2030.

Despite installed generation capacity of 13.6 GW, Nigeria's average dispatch availability remains significantly lower, reaching just 5.4 GW in the first half of 2025, up marginally from 4.8 GW in 2024. A major constraint is the low availability factor of Nigeria's 28 grid-connected power plants, which averaged below 40% in the first half of 2025. This underperformance is due to several factors, including ageing generation units and poor maintenance, liquidity challenges in the upstream segment of the Nigerian Electricity Supply Industry (NESI), and gas supply challenges. Natural gas-fired generation remained flat in 2025 but we expect an average annual growth rate of 3% during the 2026-2030 period. In June, the 180 MW Afam II gas-to-power plant was commissioned in Rivers State.

Solar PV continues to gain momentum across Nigeria, particularly through off-grid and distributed solutions. By 2030, solar generation is expected to play a major role in raising the renewable energy share of electricity to 40%. We forecast that solar PV growth will increase by an unprecedented 75% on average per year in the 2026-2030 period and grow its share of power generation from only 2% in 2025 to almost 20% in 2030.

The country's Energy Transition Plan (ETP) and the improved cost-efficiency of solar PV solutions underpin this acceleration in growth. The Distributed Access through Renewable Energy Scale-up (DARES) programme, officially launched in 2024 and funded by the World Bank, will also help drive the country's off-grid solar use in the coming years through market access support. In April, the Rural Electrification Agency (REA) signed grant agreements with eight companies, marking an important step in rolling-out the subsidy programme. The REA also signed a MoU with the pan-African company WeLight to electrify up to 2 million people with 400 minigrids and 50 town-scale microgrids. Nigerian utility Kaduna Electric unveiled plans to develop a 100 MW solar project with battery storage to strengthen electricity supply across the North West states under its franchise area

– Kaduna, Sojoto, Zamfara and Kebbi. In the education sector, the federal government approved a USD 47.5 million mini-grid solar power project across 18 public tertiary institutions under the 2025 Tertiary Education Trust Fund's intervention cycle, aimed to address irregular power supply on campuses.

Grid reliability showed signs of improvement in 2025, with only one nationwide outage by September, down from nine in total in 2024. However, in July, Lagos faced 25 days of intermittent supply and load shedding due to scheduled maintenance for the installation of Optical Ground Wire (OPGW) fibre cable along the Omotosho-Ikeja West transmission line. Transmission capacity now exceeds 8.5 GW, according to the Transmission Company of Nigeria (TCN), but the distribution segment remains a bottleneck. Distribution companies (DisCos) deliver only around 4 GWh of electricity, constrained by operational inefficiencies and heavy debt burdens. In a bid to strengthen their financial health and liquidity, the government has announced plans to introduce a minimum capital adequacy requirement as part of the license renewal process for DisCos.

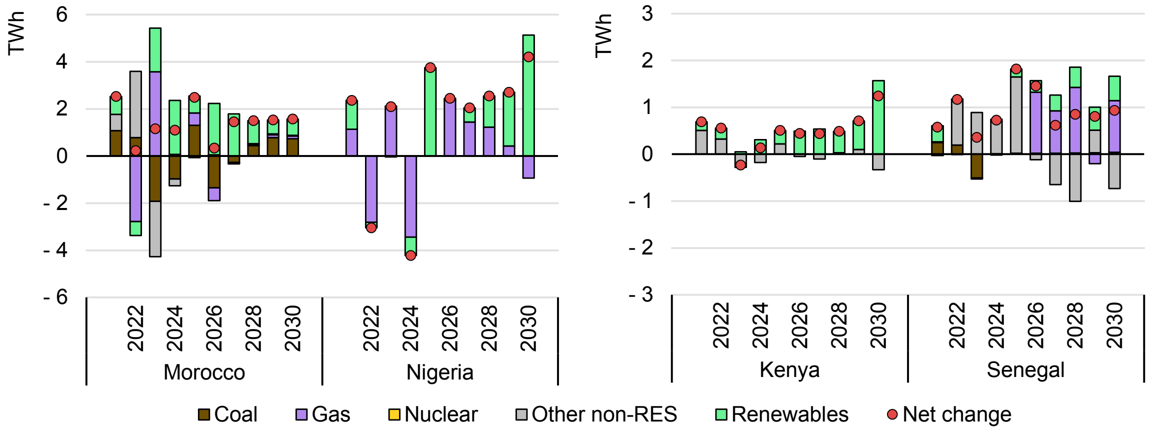
Efforts to strengthen the grid are accelerating, supported by government-led partnerships. Discussions are notably underway with EximBank of China for a USD 2 billion loan to connect Nigeria's eastern and western regions. Moreover, under Phase I of the Presidential Power Initiative (PPI), the Federal Government of Nigeria Power Company (FGNPC) signed in April 2025 a USD 328.8 million contract with China Machinery Engineering Corporation (CMEC) to boost grid capacity by 7.1 GW. The government announced that the pilot phase of the PPI already successfully added 700 MW to the grid. Additional infrastructure projects include the 132/33 kV mobile substation with a capacity of 63 megavolt-amperes (MVA) in Oyo State, commissioned in July, and the new Abeokuta Transmission Substation whose planning started in April.

International and domestic support continues to be mobilised. The European Union committed EUR 10.4 million to the Nigeria Solar for Health Project (NISHP), which will supply solar electricity to up to 100 primary healthcare centres by 2027. In parallel, Nigeria launched the USD 500 million Distributed Renewable Energy (DRE) Nigeria Fund, marking the first national fund under the DRE Africa Platform. Co-managed by the Nigeria Sovereign Investment Authority (NSIA) and Africa50, and aligned with the Mission 300 initiative, the fund aims to catalyse investments in mini-grids, solar home systems, commercial and industrial power solutions, and energy storage technologies.

Nigeria continues to advance the decentralisation of power generation and distribution under the Electricity Act 2023, which empowers authorities in the country's 36 states to regulate electricity within their jurisdictions. By mid-2025, ten states had successfully established their own regulatory frameworks. The Nigerian Independent System Operator (NISO) was officially inaugurated in April

2025 to take over the transmission system operations, following the unbundling of the transmission company. The federal government also approved in May the National Integrated Electricity Policy (NIEP), which establishes a roadmap for the NESI to align the sector with the Electricity Act 2023.

Year-on-year change in electricity generation in Morocco, Nigeria, Kenya, and Senegal, 2021-2030



Notes: Other non-renewable energy sources (RES) include oil, waste and other non-renewable sources. Data for 2026-2030 are forecast values. The plots start from 2021, whereas the x-axis labels are shown only for the even years due to limited space.

Kenya

Peak demand reached 2.4 GW in 2025, with electricity consumption forecast to grow at a brisk pace through 2030

Kenya's electricity grid hit a new all-time high in July 2025, with a system peak demand of 2 362 MW. This surge was fuelled by a combination of industrial expansion, increased urbanisation and rising residential use owing to new connections through the Last Mile Connectivity Project. The milestone demand came with no reported load shedding. However, some transmission lines exceeded 120% capacity, which highlights the critical need for infrastructure reinforcement to keep pace with surging demand. Electricity consumption is estimated to have risen by 5% in 2025, based on data through November, slightly higher than the average annual growth of 3.7% in the 2018-2024 period. We forecast a stronger growth pace of about 4.2% in 2026-2030, due to accelerating electrification and demand stimulation efforts.

In early 2025, Kenya launched its updated National Energy Policy 2025-2034 as well as the National Energy Compact, outlining new targets for 2030. We expect renewables to reach a 94% share of electricity generation by the end of the decade. To strengthen its electricity sector, Kenya aims to expand its transmission network by 8 000 km, completing pending transmission infrastructure (such as the Kenya-Uganda 400 kV interconnection) and leveraging existing and planned regional interconnectors by scaling up imported and exported power to 1 000 MW by 2030.

Kenya's goal of achieving universal access to electricity by 2030 includes expanding its distribution system by more than 200 000 km and connecting an additional 5.1 million households. To meet rising demand, Kenya aims to raise renewable power generation to around 6.3 GW, up from 3.3 GW in 2023. While the biggest installed capacity increases are planned for hydropower and geothermal, we anticipate the largest relative growth in power generation from solar PV and wind, with average annual increases of around 25% and 7.5%, respectively, between 2026 and 2030.

Kenya is targeting 10 000 new EV charging stations by 2030. In the last couple of years, the country's number of registered EVs has jumped from 475 vehicles in 2022 to almost 10 000 by October 2025, with electric two-wheelers representing around 90%. The EV adoption has been boosted by government policies such as the e-mobility tariff, reduced excise duties from 20% to 10%, and VAT exemptions for fully electric cars. The government estimates that electric two-wheelers will reach 60 000 by 2030, which will lead to an additional 415 GW electricity demand in the next five years.

With variable renewable energy sources, such as solar PV and wind power, estimated to represent 25% of electricity supply in 2030, Kenya would benefit from energy storage systems for grid reliability. Currently there is no installed utility-scale energy storage systems in the country, but a 2023 technical assessment identified BESS and pumped hydro storage as the most feasible options for the Kenyan power system. KenGen has been designated to implement a 200 MWh BESS pilot project, with targets to roll-out 400 MWh of energy storage capacity by 2030. In July 2025, KenGen commissioned a 1.16 MWh BESS to serve the company's 52 kW Modular Data Centre and guarantee stable electricity in low-grid demand periods, underscoring the role of energy storage in strengthening energy resilience. The National Energy Policy is set to support energy storage projects by establishing regulatory and institutional frameworks and guidelines, as well as developing funding models for financing energy storage capital costs.

Senegal

Progress continues towards achieving universal electricity access, now set for 2029

Senegal is on track to achieve universal electricity access by its new target year of 2029. Under its energy compact, the country plans to increase access by 2.9%

annually, aiming to reach full coverage one year ahead of the global SDG7 goal of universal access by 2030. As of 2024, an estimated 84% of the population had access to electricity. While urban areas have reached full coverage, rural areas still have further to go from a current access rate of 66%.

Electricity demand rose by an estimated 22% y-o-y in 2025 and is projected to increase by around 8% annually over the 2026-2030 period. The share of gas in electricity generation is forecast to rise from less than 1% in 2025 to around 30% by 2030, a sharp increase reflecting the introduction of natural gas into an energy mix historically dominated by oil-fired generation. The share of electricity from renewables is expected to reach 22% by 2030, up around 10 percentage points from 2025.

A 16 MW solar PV plant with 10 MW/20 MWh BESS was commissioned in 2025. Construction began on a 60 MW solar PV plant paired with a 20 MW/72 MWh battery energy storage system under the NEO Kolda project. In parallel, Energy Resources Senegal (ERS), through its subsidiary Teranga Niakhar Storage, secured financing for a 30 MW solar plant paired with a 15/45 MWh BESS in the Fatick region. The Senegalese Rural Electrification Agency (ASER), in partnership with IRENA and financed by the Abu Dhabi Fund for Development and Senegal, launched an off-grid project to provide access to 30 000 people across five underserved regions (Matam, Saint-Louis, Louga, Kaffrine, and Tambacounda). The project entails building and refurbishing solar PV minigrids of up to 2 MW. Under the *Programme d'Appui au Développement des Energies Renouvelables pour l'Accès Universel* (PADERAU), Senelec brought online four 30 kW solar plants in the Kolda and Matam regions.

On the transmission front, the construction of a 16 km-long 225 kV submarine cable was completed between the Cap des Biches thermal power plant and the Bel Air substation, under the MCASenegal II Power Compact. The 225/30 kV Diass substation was commissioned in July and is poised to play an important role in enhancing grid reliability as it services over 60% of the country's demand.

The government updated its energy strategy for 2025-2029, titled *Lettre de Politique de Développement du Secteur de l'Énergie* (LPDSE), replacing the 2019-2023 plan. The new strategy aims to ensure the sustainable and optimal use of Senegal's energy and mineral resources for economic development. Key objectives include enhancing the supply of competitive and reliable energy, with the gas-to-power strategy key to displacing heavy fuel oil in the power sector. In 2025, Senelec began converting the 335 MW Bel Air power plant from heavy fuel oil to natural gas, with plans to eventually source the gas from domestic fields, including Greater Tortue Ahmeyim (GTA) and Sangomar.

Annexes

Summary tables

Regional breakdown of electricity demand, 2023-2030

TWh	2023	2024	2025	2030	Growth rate 2023-2024	Growth rate 2024-2025	CAAGR 2026-2030
Africa	732	761	801	968	4.0%	5.2%	3.9%
Americas	6 090	6 260	6 393	7 063	2.8%	2.1%	2.0%
of which United States	4 029	4 142	4 231	4 657	2.8%	2.1%	1.9%
Asia Pacific	13 552	14 366	14 927	18 742	6.0%	3.9%	4.7%
of which China	8 573	9 170	9 639	12 250	7.0%	5.1%	4.9%
Eurasia	1 228	1 270	1 268	1 392	3.5%	-0.2%	1.9%
Europe	3 395	3 446	3 475	3 894	1.5%	0.9%	2.3%
of which European Union	2 430	2 469	2 492	2 787	1.6%	0.9%	2.3%
Middle East	1 241	1 287	1 335	1 536	3.7%	3.8%	2.8%
World	26 239	27 391	28 199	33 594	4.4%	3.0%	3.6%

Notes: Data for 2025 are preliminary; 2026-2030 are forecast values. Differences in totals are due to rounding. Summary tables include values for net electricity demand, excluding own use in the power sector. Any differences with previous editions in historical data and forecasts are due to this change in definition, in addition to normal updated revisions. CAAGR = Compounded average annual growth rate. For the CAAGR 2026-2030 reported, end of 2025 data is taken as base year for the calculation. For the entire period European Union data is for the 27 member states.

Breakdown of global electricity supply and emissions, 2023-2030

TWh	2023	2024	2025	2030	Growth rate 2023-2024	Growth rate 2024-2025	CAAGR 2026-2030
Nuclear	2 734	2 817	2 850	3 279	3.0%	1.2%	2.8%
Coal	10 637	10 788	10 760	10 284	1.4%	-0.3%	-0.9%
Gas	6 631	6 777	6 805	7 731	2.2%	0.4%	2.6%
Other non-renewables	899	866	852	521	-3.7%	-1.6%	-9.4%
Total renewables	8 993	9 858	10 734	16 059	9.6%	8.9%	8.4%
Total Generation	29 895	31 106	32 001	37 875	4.1%	2.9%	3.4%

Mt CO_2	2023	2024	2025	2030	Growth rate 2023-2024	Growth rate 2024-2025	CAAGR 2026-2030
Total emissions	13 725	13 914	13 886	13 644	1.4%	-0.2%	-0.4%

Breakdown of Asia Pacific electricity supply and emissions, 2023-2030

TWh	2023	2024	2025	2030	Growth rate 2023-2024	Growth rate 2024-2025	CAAGR 2026-2030
Nuclear	785	818	849	1 214	4.2%	3.8%	7.4%
Coal	8 722	8 929	8 828	8 842	2.4%	-1.1%	0.0%
Gas	1 477	1 536	1 523	1 867	4.0%	-0.8%	4.1%
Other non-renewables	183	162	165	120	-11.5%	1.9%	-6.2%
Total renewables	4 177	4 754	5 447	8 964	13.8%	14.6%	10.5%
Total Generation	15 344	16 199	16 812	21 006	5.6%	3.8%	4.6%

Mt CO_2	2023	2024	2025	2030	Growth rate 2023-2024	Growth rate 2024-2025	CAAGR 2026-2030
Total emissions	9 095	9 311	9 213	9 362	2.4%	-1.1%	0.3%

Breakdown of Americas electricity supply and emissions, 2023-2030

TWh	2023	2024	2025	2030	Growth rate 2023-2024	Growth rate 2024-2025	CAAGR 2026-2030
Nuclear	934	941	941	952	0.8%	0.1%	0.2%
Coal	849	820	915	650	-3.3%	11.5%	-6.6%
Gas	2 400	2 490	2 416	2 738	3.7%	-3.0%	2.5%
Other non-renewables	175	165	162	118	-5.7%	-1.8%	-6.1%
Total renewables	2 502	2 618	2 750	3 437	4.6%	5.1%	4.6%
Total Generation	6 860	7 034	7 184	7 895	2.5%	2.1%	1.9%

Mt CO_2	2023	2024	2025	2030	Growth rate 2023-2024	Growth rate 2024-2025	CAAGR 2026-2030
Total emissions	1 921	1 920	1 979	1 825	-0.1%	3.1%	-1.6%

Breakdown of Europe electricity supply and emissions, 2023-2030

TWh	2023	2024	2025	2030	Growth rate 2023-2024	Growth rate 2024-2025	CAAGR 2026-2030
Nuclear	748	785	777	812	4.9%	-0.9%	0.9%
Coal	537	481	458	238	-10.3%	-4.9%	-12.3%
Gas	679	638	696	509	-6.0%	9.1%	-6.1%
Other non-renewables	90	87	79	61	-3.3%	-9.2%	-5.0%
Total renewables	1 766	1 890	1 905	2 713	7.1%	0.8%	7.3%
Total Generation	3 820	3 882	3 915	4 333	1.6%	0.9%	2.0%

Mt CO_2	2023	2024	2025	2030	Growth rate 2023-2024	Growth rate 2024-2025	CAAGR 2026-2030
Total emissions	842	770	758	470	-8.5%	-1.6%	-9.1%

Breakdown of Eurasia electricity supply and emissions, 2023-2030

TWh	2023	2024	2025	2030	Growth rate 2023-2024	Growth rate 2024-2025	CAAGR 2026-2030
Nuclear	220	218	223	222	-0.7%	2.5%	-0.1%
Coal	288	306	316	311	6.5%	3.1%	-0.3%
Gas	667	675	669	756	1.2%	-0.9%	2.5%
Other non-renewables	16	16	15	12	3.6%	-8.2%	-4.1%
Total renewables	278	295	286	337	6.1%	-2.8%	3.3%
Total Generation	1 468	1 511	1 510	1 639	2.9%	-0.1%	1.7%

Mt CO_2	2023	2024	2025	2030	Growth rate 2023-2024	Growth rate 2024-2025	CAAGR 2026-2030
Total emissions	575	596	599	632	3.7%	0.5%	1.1%

Breakdown of Middle East electricity supply and emissions, 2023-2030

TWh	2023	2024	2025	2030	Growth rate 2023-2024	Growth rate 2024-2025	CAAGR 2026-2030
Nuclear	39	48	50	52	22.5%	3.5%	1.1%
Coal	17	15	13	12	-10.3%	-11.4%	-2.1%
Gas	1 026	1 052	1 106	1 413	2.5%	5.1%	5.0%
Other non-renewables	362	367	359	156	1.4%	-2.2%	-15.4%
Total renewables	58	73	80	208	25.2%	10.4%	20.9%
Total Generation	1 502	1 555	1 608	1 841	3.5%	3.4%	2.7%

Mt CO_2	2023	2024	2025	2030	Growth rate 2023-2024	Growth rate 2024-2025	CAAGR 2026-2030
Total emissions	819	834	854	856	1.8%	2.4%	0.1%

Breakdown of Africa electricity supply and emissions, 2023-2030

TWh	2023	2024	2025	2030	Growth rate 2023-2024	Growth rate 2024-2025	CAAGR 2026-2030
Nuclear	9	8	10	26	-8.7%	23.0%	22.3%
Coal	225	237	230	232	5.0%	-2.6%	0.1%
Gas	382	385	394	448	1.0%	2.3%	2.6%
Other non-renewables	73	69	71	54	-6.3%	3.6%	-5.3%
Total renewables	213	228	265	400	7.2%	16.4%	8.6%
Total Generation	901	926	971	1 160	2.8%	4.8%	3.6%

Mt CO_2	2023	2024	2025	2030	Growth rate 2023-2024	Growth rate 2024-2025	CAAGR 2026-2030
Total emissions	474	483	482	499	1.8%	-0.1%	0.7%

Regional and country groupings

Africa – Algeria, Angola, Benin, Botswana, Cameroon, Congo, Democratic Republic of the Congo, Côte d'Ivoire, Egypt, Equatorial Guinea, Eritrea, Ethiopia, Gabon, Ghana, Kenya, Libya, Mauritius, Morocco, Mozambique, Namibia, Niger, Nigeria, Senegal, South Africa, South Sudan, Sudan, United Republic of Tanzania, Togo, Tunisia, Zambia, Zimbabwe and other African countries and territories.[1]

Asia – Bangladesh, Brunei Darussalam, Cambodia, Chinese Taipei, India, Indonesia, Japan, Korea, Democratic People's Republic of Korea, Lao People's Democratic Republic, Malaysia, Mongolia, Myanmar, Nepal, Pakistan, People's Republic of China,[2] Philippines, Singapore, Sri Lanka, Thailand, Viet Nam and other Asian countries, territories and economies.[3]

Asia Pacific – Australia, Bangladesh, Brunei Darussalam, Cambodia, Chinese Taipei, India, Indonesia, Japan, Korea, Democratic People's Republic of Korea, Lao People's Democratic Republic, Malaysia, Mongolia, Myanmar, Nepal, New Zealand, Pakistan, People's Republic of China,[2] Philippines, Singapore, Sri Lanka, Thailand, Viet Nam and other Asian countries, territories and economies.[4]

Central and South America – Argentina, Bolivia, Brazil, Chile, Colombia, Costa Rica, Cuba, Curaçao, Dominican Republic, Ecuador, El Salvador, Guatemala, Haiti, Honduras, Jamaica, Nicaragua, Panama, Paraguay, Peru, Suriname, Trinidad and Tobago, Uruguay, Venezuela and other Latin American countries and territories.[5]

Eurasia – Armenia, Azerbaijan, Georgia, Kazakhstan, Kyrgyzstan, Russian Federation, Tajikistan, Turkmenistan and Uzbekistan.

Europe – Albania, Austria, Belgium, Belarus, Bosnia and Herzegovina, Bulgaria, Croatia, Cyprus,[6,7] Czech Republic, Denmark, Estonia, Finland, France, Germany, Gibraltar, Greece, Hungary, Iceland, Ireland, Italy, Kosovo[8] Latvia, Lithuania, Luxembourg, Malta, Montenegro, Netherlands, North Macedonia, Norway, Poland, Portugal, Republic of Moldova, Romania, Serbia, Slovak Republic, Slovenia, Spain, Sweden, Switzerland, Republic of Türkiye, Ukraine and United Kingdom.

European Union – Austria, Belgium, Bulgaria, Croatia, Cyprus,[6,7] Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Latvia, Lithuania, Luxembourg, Malta, Netherlands, Poland, Portugal, Romania, Slovak Republic, Slovenia, Spain and Sweden.

Latin America and the Caribbean (LAC): Central and South America regional grouping and Mexico.

Middle East – Bahrain, Islamic Republic of Iran, Iraq, Israel[9], Jordan, Kuwait, Lebanon, Oman, Qatar, Saudi Arabia, Syrian Arab Republic, the United Arab Emirates and Yemen.

Nordics – Denmark, Finland, Norway and Sweden.

North Africa – Algeria, Egypt, Libya, Morocco and Tunisia.

North America – Canada, Mexico and the United States.

Southeast Asia – Brunei Darussalam, Cambodia, Indonesia, Lao, People's Democratic Republic, Malaysia, Myanmar, Philippines, Singapore, Thailand and Viet Nam. These countries are all members of the Association of Southeast Asian Nations (ASEAN).

Sub-Saharan Africa: Angola, Benin, Botswana, Cameroon, Côte d'Ivoire, Democratic Republic of the Congo (DRC), Equatorial Guinea, Eritrea, Ethiopia, Gabon, Ghana, Kenya, Kingdom of Eswatini, Madagascar, Mauritius, Mozambique, Namibia, Niger, Nigeria, Republic of the Congo (Congo), Rwanda, Senegal, South Africa, South Sudan, Sudan, United Republic of Tanzania (Tanzania), Togo, Uganda, Zambia, Zimbabwe and other African countries and territories.[10]

Advanced economies – OECD member nations, plus Bulgaria, Croatia, Cyprus, Malta and Romania.

Emerging markets and developing economies – All other countries not included in the advanced economies regional grouping.

[1] Individual data are not available and are estimated in aggregate for: Burkina Faso, Burundi, Cape Verde, Central African Republic, Chad, Comoros, Djibouti, Gambia, Guinea, Guinea-Bissau, Lesotho, Liberia, Madagascar, Malawi, Mali, Mauritania, Reunion, Rwanda, Sao Tome and Principe, Seychelles, Sierra Leone, Somalia, Eswatini and Uganda.
[2] Including Hong Kong.
[3] Individual data are not available and are estimated in aggregate for: Afghanistan, Bhutan, Macau (China), Maldives and Timor-Leste.
[4] Individual data are not available and are estimated in aggregate for: Afghanistan, Bhutan, Cook Islands, Fiji, French Polynesia, Kiribati, Macau (China), Maldives, New Caledonia, Palau, Papua New Guinea, Samoa, Solomon Islands, Timor-Leste, Tonga and Vanuatu.
[5] Individual data are not available and are estimated in aggregate for: Anguilla, Antigua and Barbuda, Aruba, Bahamas, Barbados, Belize, Bermuda, British Virgin Islands, Cayman Islands, Dominica, Falkland Islands (Malvinas), Grenada, Guyana, Montserrat, Saba, Saint Eustatius, Saint Kitts and Nevis, Saint Lucia, Saint Pierre and Miquelon, Saint Vincent and the Grenadines, Sint Maarten, and the Turks and Caicos Islands.
[6] Note by Türkiye: The information in this document with reference to "Cyprus" relates to the southern part of the Island. There is no single authority representing both Turkish and Greek Cypriot people on the Island. Türkiye recognises the Turkish Republic of Northern Cyprus (TRNC). Until a lasting and equitable solution is found within the context of United Nations, Türkiye shall preserve its position concerning the "Cyprus issue".
[7] Note by all the European Union Member States of the OECD and the European Union: The Republic of Cyprus is recognised by all members of the United Nations with the exception of Türkiye. The information in this document relates to the area under the effective control of the Government of the Republic of Cyprus.
[8] The designation is without prejudice to positions on status and is in line with the United Nations Security Council Resolution 1244/99 and the Advisory Opinion of the International Court of Justice on Kosovo's declaration of Independence.
[9] The statistical data for Israel are supplied by and under the responsibility of the relevant Israeli authorities. The use of such data by the OECD and/or the IEA is without prejudice to the status of the Golan Heights, East Jerusalem and Israeli settlements in the West Bank under the terms of international law.
[10] Individual data are not available and are estimated in aggregate for: Burkina Faso, Burundi, Cabo Verde, Central African Republic, Chad, Comoros, Djibouti, Gambia, Guinea, Guinea-Bissau, Lesotho, Liberia, Malawi, Mali, Mauritania, Sao Tome and Principe, Seychelles, Sierra Leone and Somalia.

Abbreviations and acronyms

AEMO	Australian Energy Market Operator
AI	artificial intelligence
BNetzA	Bundesnetzagentur – German Federal Network Agency
BESS	battery energy storage systems
BEVs	battery electric vehicles
CAGR	compound annual growth rates
EAF	electric arc furnace
ERCOT	Electric Reliability Council of Texas
EV	electric vehicle
FiT	feed-in-tariff
GDP	gross domestic product
GPUs	graphics processing units
IMF	International Monetary Fund
MoU	Memorandum of Understanding
NEVs	new energy vehicles
OCGT	open cycle gas turbine
PHWRs	pressurised heavy water reactors
PPA	power purchase agreements
PPP	Purchasing power parity
PUE	Power Usage Effectiveness
PV	photovoltaic
RES	renewable energy sources
STCs	Small-scale Technology Certificates
SMR	small modular reactors
VRE	variable renewable energy

Units of measure

g CO_2	gramme of carbon dioxide
g CO_2/kWh	gramme of carbon dioxide per kilowatt hour
GW	gigawatt
GWh	gigawatt hour
kW	kilowatt
MW	megawatt
MWh	megawatt-hour
Mt/yr	million tonnes per year
Mt CO_2	million tonnes of carbon dioxide
Mt CO_2/yr	million tonnes of carbon dioxide per year
TWh	terawatt-hour

See the IEA glossary for a further explanation of many of the terms used in this report.

IEA Publications
International Energy Agency
Website: www.iea.org
Contact information: www.iea.org/contact

Typeset in France by IEA - February 2025
Cover design: IEA
Photo credits: © Shutterstock