Electricity 2025

Analysis and forecast to 2027

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Abstract

Strong growth in electricity demand is raising the curtain on a new Age of Electricity, with consumption set to soar through 2027. Electrification of buildings, transportation and industry combined with a growing demand for air conditioners and data centres is ushering a shift toward a global economy with electricity at its foundations.

The International Energy Agency's Electricity 2025 provides a deep and comprehensive analysis of all these trends as well as recent policy developments. For the period 2025 through 2027, it forecasts electricity demand, supply and carbon dioxide (CO2) emissions for select countries, by region and worldwide. The report explores emerging trends such as growing electrification, expanding power systems and an increasing share of weather-dependent energy sources in the generation mix. Through this lens, it assesses resource adequacy and the methods needed to ensure the security, resilience and reliability of power systems and electricity supply. This year's report, now in its sixth year, includes a special feature on China's evolving power demand as well as a section on the phenomenon of negative wholesale electricity prices in some markets.

Acknowledgements, contributors and credits

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Executive summary

Strong growth in electricity demand is heralding a new Age of Electricity, with demand set to soar through 2027

Global electricity consumption is expected to increase at the fastest pace in years over the 2025-2027 forecast period of this report, fuelled by growing industrial production, rising use of air conditioning, accelerating electrification, and the expansion of data centres worldwide. Global electricity demand rose by 4.3% in 2024 and is forecast to continue to grow at close to 4% out to 2027. Over the next three years, global electricity consumption is forecast to rise by an unprecedented 3 500 TWh. This corresponds to adding more than the equivalent of a Japan to the world's electricity consumption each year. This is also a sharp acceleration over the 2.5% increase in 2023, when strong gains in China, India and Southeast Asia were tempered by declines in advanced economies.

Emerging and developing economies, led by China, are the main drivers of electricity demand growth

Most of the additional demand for electricity through 2027 will come from emerging economies, which are expected to make up 85% of the growth. More than half of global electricity demand growth in 2024 came from China, where it grew by 7% in 2024, similar to the previous year. Electricity demand in China is forecast to increase on average by 6% annually out to 2027. India, Southeast Asian countries and other emerging markets are also expected to record strong demand growth, supported by economic expansion and rising air conditioner ownership. India's electricity demand is forecast to grow at an average 6.3% annually over the next three years, stronger than the 2015-2024 average growth rate of 5%. While many emerging economies are seeing robust electricity demand growth, Africa is lagging. Although significant progress has been made in recent years, 600 million people in sub-Saharan Africa still do not have access to reliable electricity.

Electrification is progressing rapidly in China, where the share of electricity in final energy consumption (28%) is much higher than in the United States (22%) or the European Union (21%). China's electricity consumption has been growing faster than its economy since 2020, underscoring the speed at which electrification across all sectors is taking hold. In the three-year period 2022-2024, industry accounted for almost 50% of electricity demand growth, with the commercial and residential sectors combined making up another 40%. The industrial sector became more electricity intensive, with one-third of the growth in demand coming from the manufacturing of solar PV modules, batteries and electric vehicles. In 2024, these industrial sectors consumed more than 300 TWh of electricity annually – as much as Italy uses in a year. Over our forecast period, the industrial sector will continue to make up the largest share of China's demand growth. At the same time, the rising stock of air conditioners, growing electric vehicle charging demand and the expansion of data centres and 5G networks will continue to play a significant role in China's increasing electricity consumption over the next three years.

Electricity consumption by data centres in China could double out to 2027, though projections indicate a wide range of uncertainties. We estimate that data centres in China consumed over 100 TWh of electricity in 2024. Future projections from Chinese institutions indicate a wide range of possible demand levels from data centres in 2027, highlighting the need for further data collection and analysis on the sector. Compared with other major drivers of electricity demand in China, data centres' contribution to growth over 2022-2024 was limited, accounting for around 3% of the additional demand. However, their share of growth, based on the projections by Chinese institutions, could increase to 6% over the next three years.

Electricity demand in advanced economies is rising again, bucking the trend of the past 15 years

While the electricity consumption of advanced economies as a whole remained almost unchanged in 2024 compared with 2021, they are expected to account for 15% of global demand growth over the 2025-2027 period. Many advanced economies – such as Australia, Canada, the European Union, Japan, Korea and the United States – are expected to see electricity consumption rise through 2027 following increases in 2024. In advanced economies, electricity demand – both in total and per capita – has stayed relatively flat or even declined since 2009 even as the economies themselves have continued to grow. This dynamic in advanced economies reflected a combination of increased efficiency gains across all end-use sectors, most notably in lighting and appliances, as well as the restructuring and relocation of heavy industries over the past several decades. Now, once again, electricity demand in advanced economies is expected to start rising significantly alongside economic growth, bucking the trend of the past 15 years. This is driven by higher consumption from the deployment of electric vehicles, air conditioners, data centres and heat pumps, among other end-use technologies.

In the United States, the world's second-largest electricity consumer after China, demand rebounded in 2024, growing by 2% to reach a new high. This followed a 1.8% decline in 2023 due to mild weather and weaker manufacturing activity. We expect US electricity demand to grow at an average annual rate of 2%

over the 2025-2027 period, which is equivalent to adding the total electricity demand of California over the next three years. This is an upward revision from our forecast in January 2024, and is largely due to higher consumption from the data centre sector. The other significant contributors to electricity demand growth in our forecast are households, electric vehicles and the industrial sector, notably large new consumers such as semiconductor manufacturers.

Electricity demand in the European Union is recovering from the economic slowdown that has affected the region in recent years, but it is not expected to return to 2021 levels before 2027. EU electricity consumption declined by 3% in 2022 and again in 2023, taking it down to levels last seen two decades ago. The modest growth of 1.4% in 2024 was supported by the residential and commercial sectors, led by increased use of heat pumps and electric vehicles and higher demand from data centres. By contrast, industrial electricity consumption remained relatively flat, having fallen by around 6% in both 2022 and 2023. While primary metals and various chemical sectors saw higher output and increased electricity demand compared with the previous year, the gains were offset by declines in the automotive, machinery and related industries. Electricity prices for energy-intensive industries in the European Union in 2024 were well below the record highs seen in 2022 and slightly lower than in 2023. But they were still, on average, double those in the United States and 50% higher than in China.

Low-emissions sources are expected to meet all the growth in electricity demand between now and 2027

Record-high electricity generation from renewables and nuclear is expected to meet all the additional global demand over the next three years. Renewables – such as solar, wind and hydropower – are set to meet about 95% of the electricity demand growth in our forecast period. In 2025, they are forecast to provide more than one-third of total electricity generation globally, overtaking coal. Renewables are expected to more than meet demand growth in advanced economies, reducing fossil fuel-fired generation. In China, rapid expansion of renewables is expected to meet around 90% of new electricity demand, though weather-related events and unexpected electricity consumption changes can affect this trend in individual years.

The rapid expansion of ever cheaper solar PV is expected to account for roughly half of global electricity demand growth to 2027, up from 40% in 2024. Globally, solar PV generation hit the 2 000 TWh mark in 2024, producing 7% of global electricity generation, up from 5% in 2023. Over the next three years, roughly 600 TWh of additional electricity will be generated from solar each year, equivalent to Korea's annual consumption. Solar PV is thriving globally, setting records in both emerging markets and advanced economies. Electricity generation from solar PV surpassed that from coal in the European Union in 2024, with its share in the generation mix exceeding 10%. China, the United States and India are all set to see solar PV's share reach 10% over the forecast period as well. The strong growth trend in solar PV is accompanied by continued expansion in wind generation, which is forecast to meet around one-third of additional global electricity demand in 2025-2027.

Nuclear power generation will reach a new high in 2025 and continue to rise steadily over the following two years, setting further records. The strong growth will be fuelled by the recovery in French nuclear power output, restarts in Japan and new reactors entering operation in China, India, Korea and other countries**.** The growth trend in nuclear generation also reflects a strong comeback for the technology in policy circles, highlighting its importance as a stable backbone in low-emissions energy systems for an increasing number of countries.

Emissions from electricity generation are plateauing as renewables limit fossil-fired output

Over the 2025-2027 forecast period, global carbon dioxide (CO_2) emissions from electricity generation are expected to plateau after increasing by 1% in 2024. This is a slight slowdown compared with the rise of 1.4% in 2023, owing to the expanding use of renewables and a levelling off in fossil fuel-fired generation. However, at about 13 800 million tonnes of CO_2 in 2024, emissions from electricity generation remain the highest of any sector. Global coal-fired generation is expected to stagnate over the forecast period, after increasing by 1% in 2024. Declining emissions in the European Union and the United States are mostly offset by increases in India and Southeast Asia in our forecast period. Nevertheless, the strong expansion of low-emissions energy sources in many regions will reduce the share of global coal-fired generation below 33% for the first time this century over the forecast period. Trends in China, where more than half of world's coal-fired electricity generation takes place, will continue to be the largest source of uncertainty, since weather events or economic fluctuations can considerably affect coal-fired generation in individual years.

Natural gas-fired generation globally is expected to see moderate-but-steady average annual growth of around 1% in 2025-2027, **following a 2.6% surge in 2024 and a 1.3% increase in 2023.** Declining gas-fired output in Europe and the Americas amid growing generation from clean energy sources is set to be more than offset by strong increases in the Middle East and Asia. In the Middle East, robust electricity demand growth and oil-to-gas switching in the power sector will be major drivers. At the same time, rising electricity consumption in Asia will lead to higher gas-fired generation, which will remain important for power system flexibility needs. Even in regions where we expect gas-fired generation to decline, its role in providing flexibility to the system and acting as backup capacity will be essential for maintaining security of supply.

Wholesale electricity prices declined in some regions, but higher volatility signals the need for more flexibility

In the European Union, India, the United Kingdom and the United States, wholesale electricity prices fell by around 20% on average in 2024 compared with the previous year. This was broadly in line with the fall in global energy commodity prices. Nevertheless, prices in these regions – except for the United States and the Nordic region in Europe – are still significantly above their pre-Covid levels.

Though still relatively uncommon in many power markets, some regions have seen increasing occurrences of negative wholesale prices in recent years. These include the Australian regions of Victoria and South Australia, southern California in the United States, and a growing number of European countries. Negative prices broadly signal insufficient flexibility in the system due to technical, regulatory or contractual reasons. Negative prices can, in some cases, serve as an incentive for more flexible supply and demand, as well as the use of storage solutions. However, the price signals alone may not suffice for investing in increased system flexibility. Adequate regulatory frameworks, market designs and tariff structures are also essential for promoting more flexibility in the system.

Several short-lived *Dunkelflaute* events, when electricity generation from wind and solar PV combined reached very low levels, resulted in extremely high price spikes during several hours in the winter of 2024/2025 in Northern Europe. The price spikes only had a very limited impact on average prices but acted as important signals to incentivise flexible generators to produce more and for flexible consumers to reduce their consumption, as well as facilitating efficient imports and exports of electricity. Such events can act as potential stress tests for the system, and the recent occurrences were managed successfully without any impact on the supply of electricity, highlighting the resilience of the power systems and the underlying short-term market structures.

Increasing weather impacts on power systems highlight the importance of enhancing electricity security

Extreme weather events such as storms, droughts and heatwaves led to widespread power disruptions in 2024. The United States saw large-scale power outages in early January due to massive winter storms that affected a wide area ranging across multiple states. Hurricanes were particularly frequent in the Atlantic in 2024, which affected many US states and Caribbean countries during the summer, causing extensive damage and power supply disruptions. Victoria, Australia, was similarly hit by a major outage due to a storm that damaged transmission infrastructure. At the same time, reduced hydropower output due to droughts strained power systems across the world, with Ecuador and Colombia strongly affected by El Niño weather effects. Mexico faced supply tightness during elevated electricity demand periods amid heatwaves and low hydropower generation. Such events highlight the need to increase resiliency against the impacts of extreme weather on power systems.

Having sufficient dispatchable capacity and storage, among other flexibility options such as demand-side response and interconnections, will be essential for enhancing electricity security. As both electricity supply and demand become more weather dependent, temporary periods with reduced weather-dependent supply may put significant strain on the power system. This is especially the case if such events coincide with elevated electricity demand due to extreme weather such as winter storms or intense heatwaves and fuel supply disruptions or outages in power plants. When planning for resource adequacy to reliably meet electricity demand with available supply, taking into consideration the unpredictable nature of weather events is becoming increasingly important.

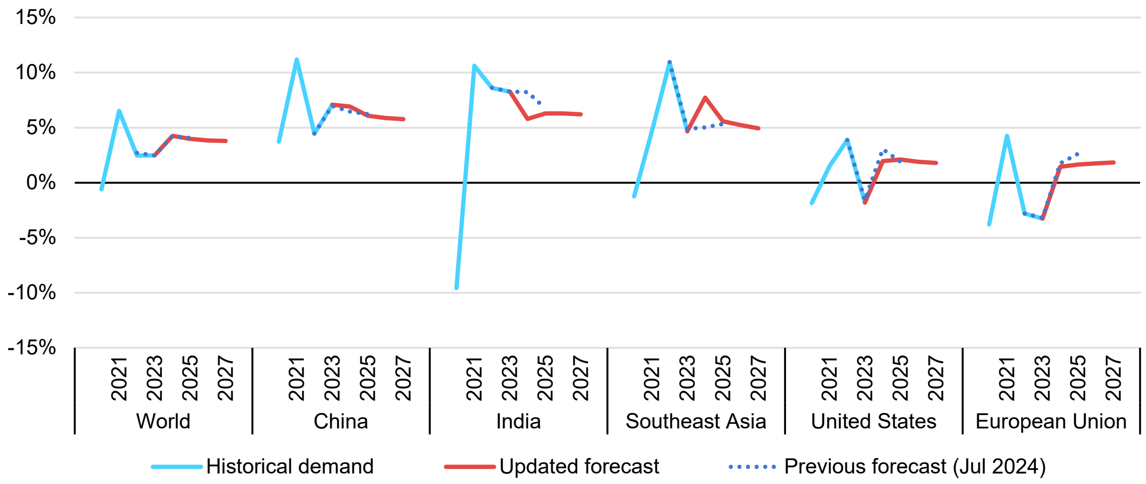
Demand: Entering the Age of Electricity

Rapid electricity demand growth across many regions foreshadows new era

Strong growth in global power demand in 2024, fuelled by the expansion of electrification, is ushering in the new Age of Electricity. All the additional demand in our 2025-2027 forecast is set to be covered by low emissions technologies. Electricity consumption rose by an estimated 4.3% y-o-y in 2024, up from 2.5% in 2023, with growth expected to continue at a robust 3.9% in our outlook period. In 2024, most of the growth in global electricity demand occurred in emerging economies, with the People's Republic of China (hereafter, "China") accounting for 54% of the total. Out to 2027, developing economies will remain the engines of growth, accounting for around 85% of additional global electricity demand, with China providing more than half of the gains.

Since 2020, China's power demand has been growing faster than its economy, boosted by an array of factors, including rapid growth in electricity-intensive manufacturing of clean energy technologies, rising ownership of air conditioners, increasing penetration of electric vehicles and expanding data centres and the 5G sectors. This year's report includes a special section on China (see *Spotlight: What is driving China's electricity demand growth?),*

Year-on-year percent change in electricity demand in selected regions, 2020-2027

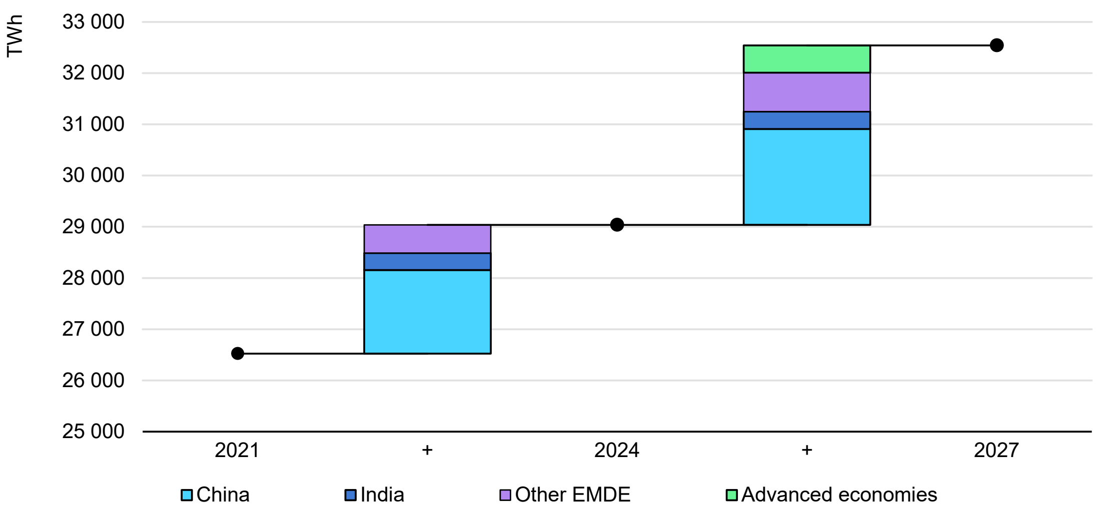


Note: Data for 2025-2027 are forecast values. The years on the x-axis start at 2020.

Over our forecast period, India is also expected to continue recording strong growth in electricity consumption, and will account for 10% of the total increase in global demand to 2027 amid robust economic activity and rapidly rising air conditioning (AC) stock. Peak electricity load in India has shown strong growth in recent years, and a dedicated section in this chapter provides a detailed analysis of peak load trends and the successful impact of India's time-of-use tariffs.

Electricity demand in advanced economies, in aggregate, was effectively unchanged in 2024 compared to 2021. During this period, the growth in global electricity demand has come from emerging economies and developing markets. However, through 2027, we expect the share of advanced economies in additional electricity demand to increase to around 15%, as electrification of the transport and heating sectors continues, and data centres expand rapidly. While in the United States the growth projections for data centres are a key driver of the electricity demand trends, in the European Union uncertainty surrounding the recovery in energy-intensive industries and the impact on electricity demand is a central topic and is covered in detail.

Change in electricity demand by region, 2023-2027

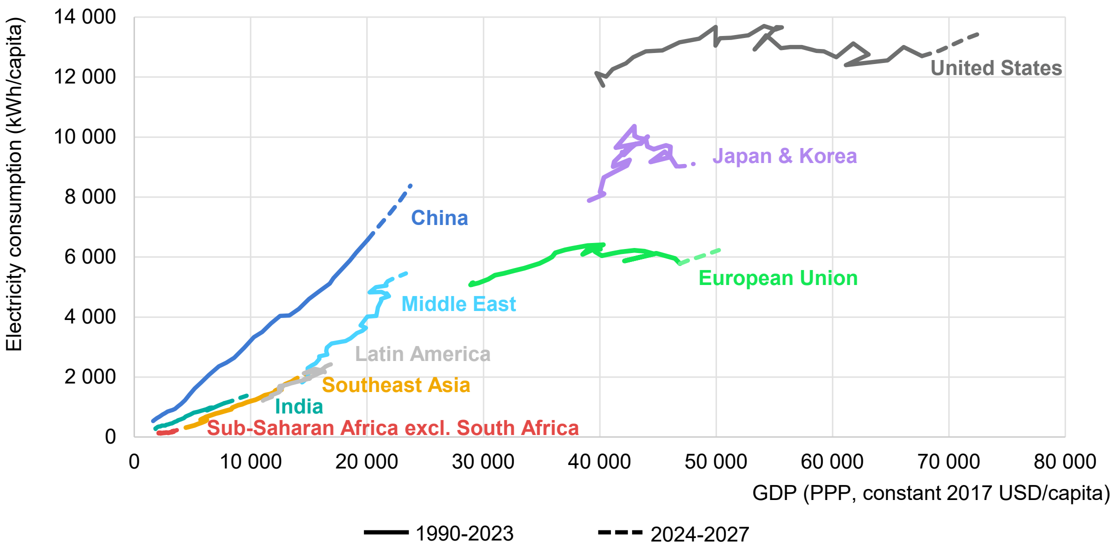


Note: EMDE = Emerging market and developing economies.

Electricity demand in advanced economies is rising, reversing a 15-year declining trend

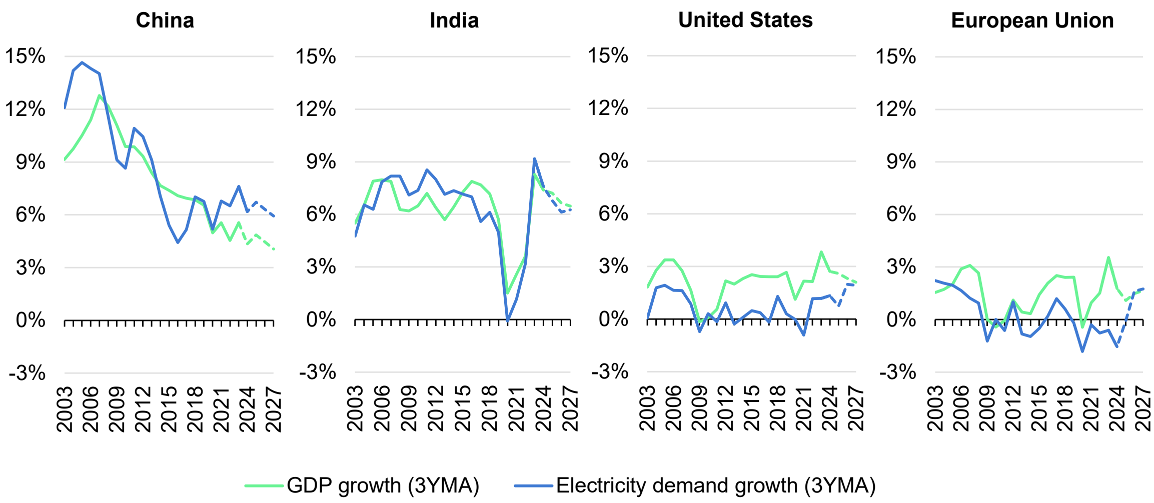
In advanced economies, electricity demand – both in total and per capita – has stayed relatively flat or even declined since 2009, as in the case of Japan, although GDP PPP per capita has continued to rise. This change in the GDP and electricity demand dynamic in advanced economies reflects a combination of increased efficiency gains across all end-use sectors, most notably in LED lighting and appliances as well as heavy industries moving abroad to developing economies over the past several decades. Now, once again, we expect electricity demand in advanced economies to start rising alongside economic growth, in a reversal of the trend over the past 15 years. This is driven by a combination of rising consumption from electric vehicles, air conditioners, data centres and heat pumps.

Evolution of per capita electricity consumption and GDP in selected regions throughout the years, 1990-2027



Note: GDP is based on the October 2024 edition of IMF World Economic Outlook.

Growth rates of electricity demand and GDP in selected regions, 2003-2027



Note: 3YMA = 3-year moving average. GDP growth is based on the October 2024 edition of the IMF World Economic Outlook.

Historically, electricity consumption and GDP growth have generally gone hand in hand as a stronger economic environment boosts industrial activity, manufacturing and services, among other sectors, which result in increased power demand. At the same time, access to affordable and reliable electricity boosts the growth in these sectors, translating into economic development. This is especially true for emerging and developing economies.

However, Africa is lagging behind due to the insufficient pace of growth in its energy supply. Over the last 30 years, electricity use per capita in sub-Saharan Africa has been effectively flat. Although significant progress has been made in recent years, 600 million people in sub-Saharan Africa still do not have access to reliable electricity. The lack of sufficient access to reliable electricity is dramatically impacting the region by inhibiting economic growth. In sub-Saharan Africa, excluding South Africa, GDP purchasing power parity (PPP) per capita is now 50% higher than in 1990. By contrast, during the same period, the GDP per capita of other developing economies such as Southeast Asia has increased threefold and that of India fourfold. While the availability of sufficient and reliable electricity is not the only determinant of economic prosperity, its scarcity is a bottleneck to growth.

Spotlight: What is driving China's electricity demand growth?

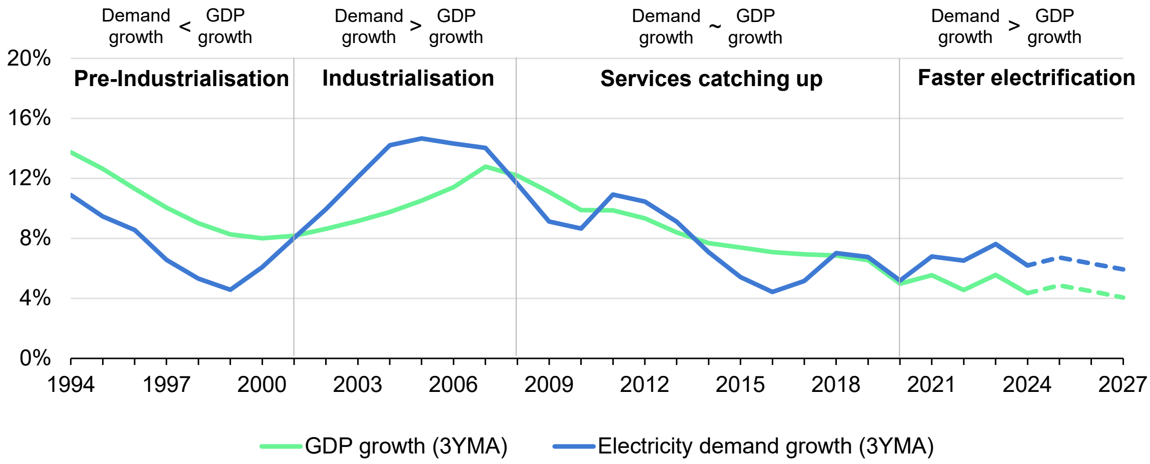
China's gross electricity demand approached the 10 000 TWh mark at the end of 2024. More than one-third of global electricity consumption has taken place in China since 2023. Even though Chinese economic growth shows signs of slowing down, electricity demand in recent years has remained robust. Electricity consumption increased by about 7% y-o-y in both 2023 and 2024, despite slower economic growth of around 5%. Similarly, over the next three years (2025-2027), while projected GDP growth is forecast at around 4% on average according to the IMF, we expect electricity demand to increase by a more robust 6%. This means that China will be adding more than three times the annual electricity demand of Canada in the next three years.

China's strong electricity demand growth in recent years has been driven by a multitude of factors. On the industry side, alongside traditional industries, rapid growth in the electricity-intensive manufacturing of solar PV modules, batteries and electric vehicles (EV) amid continued electrification and steady output in other conventional sectors have increased demand. Outside of industry, the rising AC stock, growing EV charging and the ascent of data centres and 5G networks are also important factors. Alongside these major catalysts, increased electrification across all sectors is further contributing to electricity demand growing faster than the GDP.

Electricity demand in China has been growing faster than GDP since 2020

In China, both electricity demand and GDP rose on average by about 6.5% annually during 2016-2019. However, in 2020 demand growth exceeded GDP growth, a trend which continues. Chinese electricity consumption in 2023 and 2024 was particularly strong, with annual growth rates of about 7%. During the same period, GDP is estimated to have grown more slowly, by an average of 5%. Heatwaves and the resulting need for cooling have driven up electricity consumption in recent years, however, we estimate that the weather effect, while significant, was limited to around 0.6 percentage, indicating that the main drivers of growth have been other factors.

Growth rates of electricity demand and GDP in China, 1994-2027

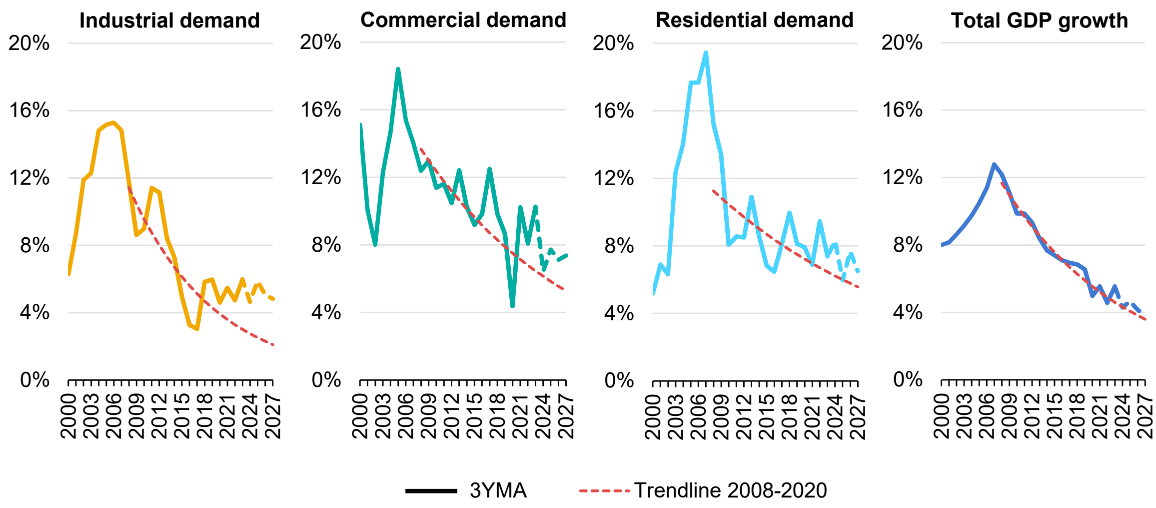


Note: 3YMA stands for 3-year moving average. GDP growth is based on the October 2024 edition of the IMF World Economic Outlook.

What is clear is that from 2020 onward Chinese electricity demand growth has outpaced GDP due to a convergence of factors that paved the way for increased electrification in the country. Our analysis shows that the rapid electrification across all sectors has had a major transformative impact of increasing electricity demand beyond economic growth. The share of electricity in total final consumption in China is estimated at 28% in 2024, up from 27% in 2023. The share of electricity in total final consumption is currently estimated at 22% in the United States and 21% in the European Union.

In sectors outside of industry, important catalysts of higher electricity consumption include the growing stock of air conditioners, expansion of data centres and 5G, and stronger EV charging demand. In the industry sector, alongside rising electrification, the sharp increase in electricity-intensive production of new energy products such as PV modules, batteries and EVs has been a major source of growth in recent years. While overall GDP is following its 2008-2020 trend, industrial electricity demand growth has been higher than the economy's pace of expansion. As a result, even though the economy is slowing down in aggregate, total electricity demand growth remains robust as the country overall becomes more electricity-intensive.

Growth rates of sectoral electricity demand and GDP in China, 2000-2027



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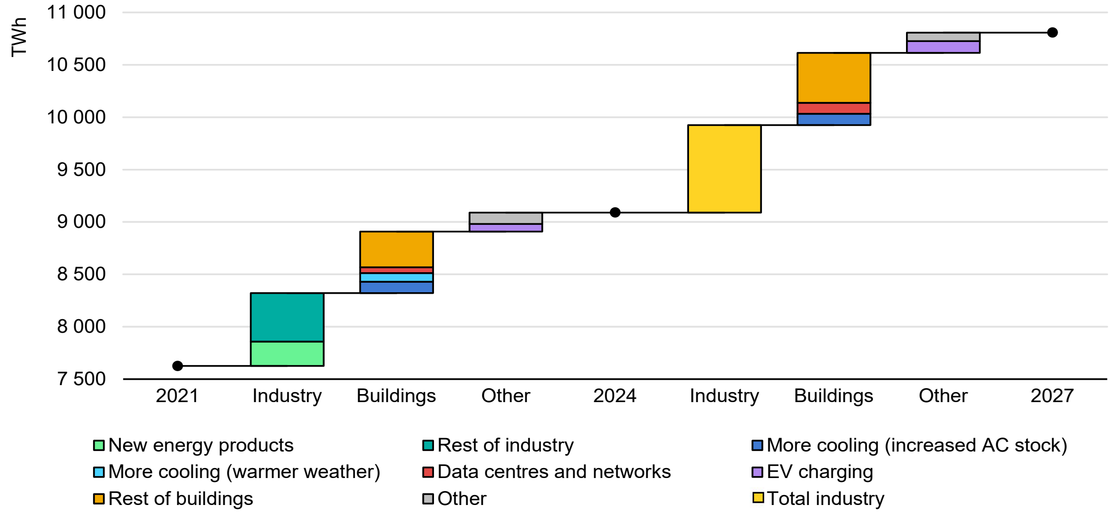
Note: 3YMA = 3-year moving average. GDP growth is based on the October 2024 edition of the IMF World Economic Outlook.

50% of additional electricity demand set to come from industry, with a steady boost from new energy products

In China, industry consumes approximately 60% of all electricity, much higher than in any other country in the world (32% on average in the OECD). Over the three-year period from 2022 to 2024, 48% of the increase in Chinese electricity demand came from the industry sector. The manufacturing of PV modules, batteries, and EVs excluding the processing of associated materials are estimated to have consumed around 320 TWh of electricity in 2024 – as much electricity as Italy uses in a year. The increase in consumption of these sectors has been remarkable in recent years, which rose by more than 230 TWh over 2022-2024. During this period, new energy products made up nearly 35% of the increase in industrial electricity demand and 16% of the growth in total electricity use across China. Including the numerous electricity-intensive upstream processes associated with these products that take place in China, such as the refining and processing of the related materials, can further boost these numbers.

Over 2025-2027, we expect the industry sector to make up roughly 50% of the additional demand growth. Industrial demand, excluding that associated with new energy products, is forecast to record higher growth than it recorded in the prior three-year period of 2022-2024. Growth stems from the accelerated pace of electrification in industries and uptake of heat pumps. Another major factor is the baseline effect from the Covid-19 lockdowns that impacted many industries in 2022, depressing electricity demand during that period. New energy products will continue to provide a significant share of industrial demand growth, as the manufacturing of PV modules, batteries and EVs is expected to remain robust.

Estimated drivers of change in electricity demand in China, 2021-2027

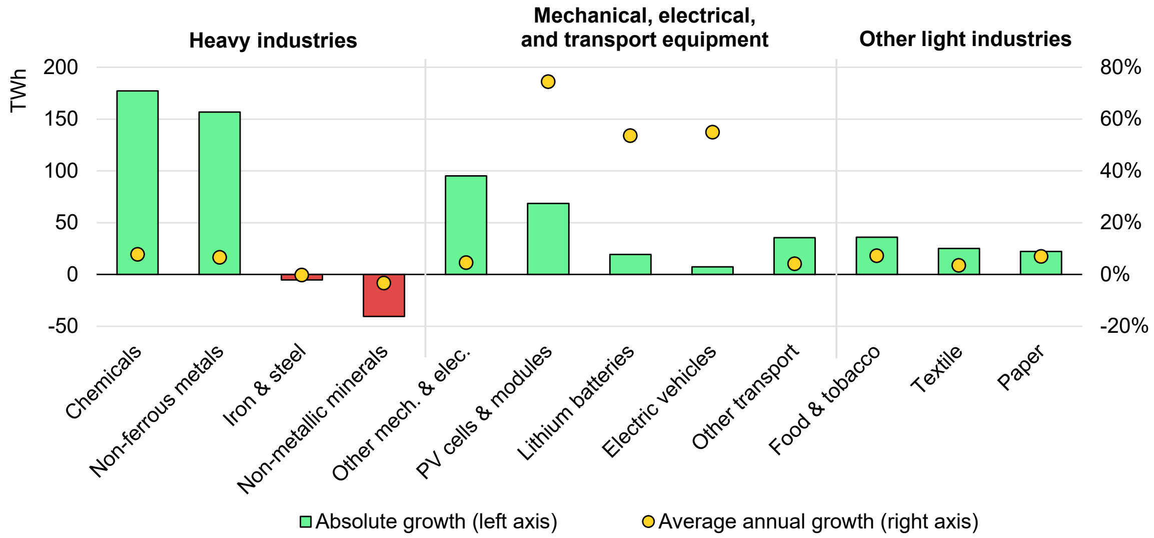


Notes: Buildings corresponds to residential and commercial sectors. New energy products (solar PV, EVs and batteries) include electricity consumption of the manufacturing processes of these products and exclude that from upstream processes such as mining and processing of associated materials.
Source: IEA analysis based on IEA World Energy Balances (2024), National Bureau of Statistics of China (2024), China Power (2025).

Production of PV modules has expanded at a dramatic pace in recent years, with output in China rising 3.5 times, from 180 GW in 2021 to more than 630 GW in 2024. With growing overcapacity concerns given the actual demand and the high number of inventories in China, a slowdown in PV manufacturing over the next several years cannot be ruled out. Nevertheless, production of solar PV modules currently makes up most of the electricity demand from the manufacturing of new energy products and will continue to have a high share over our forecast period.

EV factory output in China has increased from 3.5 million vehicles in 2021 to around 13 million vehicles in 2024. Similarly, production of lithium batteries rose from nearly 250 GWh to about 900 GWh during the same period. With the production of both batteries and EVs expected to continue growing, electricity consumption associated with the manufacturing of these products will remain robust.

Breakdown of industrial electricity demand growth in China, 2024 vs 2021



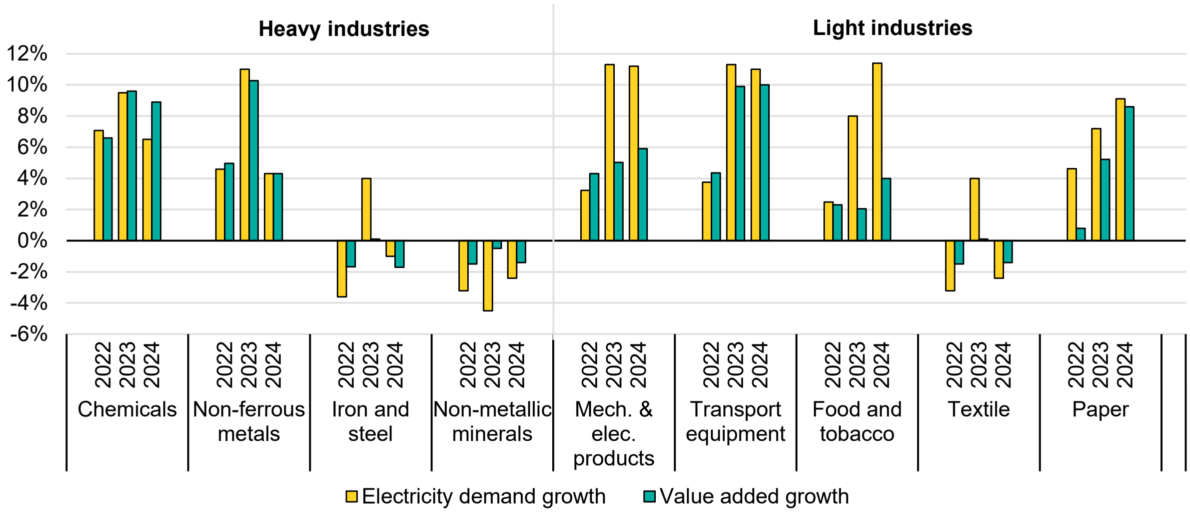
Note: The electricity consumption associated with the manufacturing of mechanical, electrical and transport equipment does not include the electricity consumption of the associated upstream processes.
Source: IEA analysis based on IEA World Energy Balances (2024), National Bureau of Statistics of China (2024), China Power (2025).

Industrial electricity demand has been growing faster in recent years than industrial value added, indicating that the Chinese industry is becoming more electricity-intensive. This is particularly the case in light industries, such as textile, food and tobacco, and mechanical and electrical products.

Apart from the growth in electricity-intensive manufacturing of new energy products, one other trend of industrial electrification is the replacement of fossil fuel-based heating for certain processes with electric heating in some industries such as chemicals and refineries. At the same time, industrial heat pumps are also increasingly being installed, after China announced plans to increase the number of heat pumps in light industries.

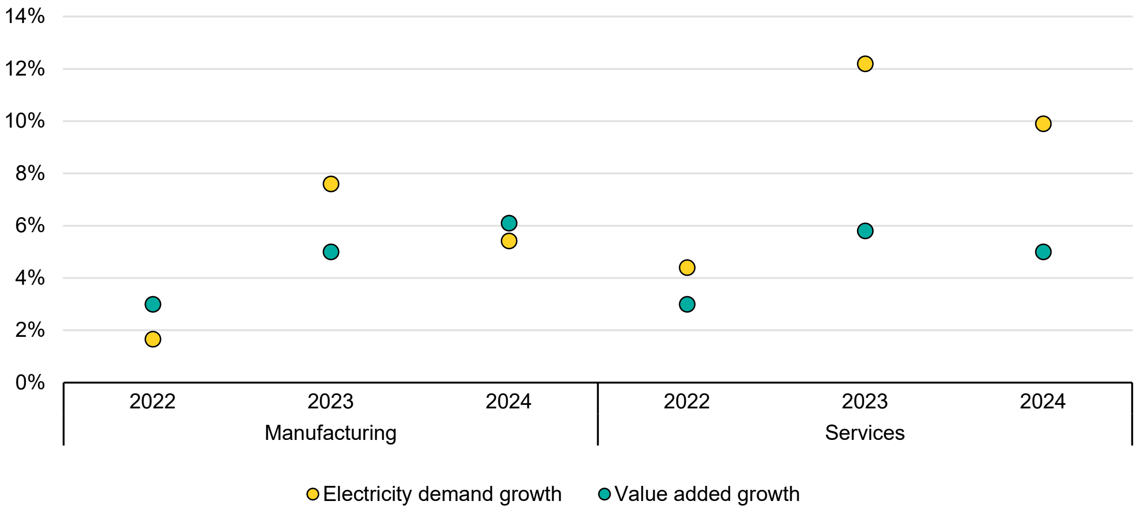
China's dual carbon goals to peak CO_2 emissions before 2030 and achieve carbon neutrality before 2060 include a strong policy commitment to industrial electrification. Improved automation in manufacturing is also likely to result in higher electricity demand. The stock of industrial robots in China has roughly doubled since 2020, reaching 2 million units in 2024. We estimate this alone could correspond to the increase in electricity demand of more than 15 TWh over the period 2021-2024.

Electricity demand growth vs. value added growth in manufacturing sector in China, 2022-2024



Source: IEA analysis based on data from IEA World Energy Balances (2024), National Bureau of Statistics of China (2024), China Power (2025).

Electricity demand growth vs. value added growth in manufacturing and services sectors in China, 2022-2024



Note: Services covers tertiary industry as categorised in China's national publications on economic and energy statistics.
Source: IEA analysis based on data from IEA World Energy Balances (2024), National Bureau of Statistics of China (2024), China Power (2025).

Rising AC ownership, EV charging, and data centres and 5G are significant drivers of electricity demand

The increasing **air conditioning (AC) stock** in recent years is estimated to have made up about 18% of the total electricity demand growth in the buildings sector and 8% of the total electricity demand, and we expect this trend to continue out to 2027 at a similar share. Residential AC stock in China has been growing annually by around 6% on average since 2019. Currently, it is estimated that 80% of households in China are equipped with an AC unit. For reference, this share is above 90% in Japan and the United States. In the most recent years, the cooling load in summer has reportedly accounted for 30% of the peak load in China, and this proportion exceeds 40% in some provinces. On 24 July 2024, peak load saw a new record of 1 451 GW, more than 7% (+100 GW) higher than last year's record. China's average load for cooling in summer 2024 is estimated to have reached 420-450 GW, an increase of almost 100 GW from 355 GW in 2023.

Data centres and growth in 5G networks have also been significant contributors to recent electricity demand growth in China. We estimate data centres and telecommunication networks together accounted for around 13% of the demand growth in the buildings sector in 2021-2024 and around 4% of the total electricity demand. The share of data centres alone, excluding networks, was 3%. Out to 2027, this share could double, increasing to 6% based on projections from China. Nevertheless, there is considerable uncertainty associated with both historical estimates as well as future projections of the sector. A detailed coverage of projections and the reasons for the uncertainty can be found below (see *Understanding China's data centre and 5G electricity consumption projections).*

Over the 2025-2027 period, we expect electricity consumption in the buildings sector to rise faster, as the share of data centres and networks in growth increases and as electricity consumption in businesses and households rises due to economic growth, supported by services and appliances. Electricity consumption per capita in China is still roughly half of that in the United States. And while Chinese per capita electricity consumption has already exceeded that of the European Union at the end of 2022, per capita electricity use of Chinese households is still 75% lower than the average for EU households.

Electric vehicle charging in China is emerging as a significant driver of electricity demand. EV charging consumed about 80 TWh of electricity in 2023 and just over 100 TWh in 2024. The growth in EV charging is estimated to have made up about 5% of the total electricity demand increase in 2021-2024, and is forecast to rise to 7% over the period 2025-2027. The trend is reflective of the strong growth seen in EV ownership in recent years. By the end of 2024, China's new energy vehicle (NEV[1]) fleet reached over 30 million, around 70% of which were battery electric

[1] NEVs include fuel cell vehicles in addition to EVs, although these account for less than 0.1% of total NEV production, sales and ownership values.

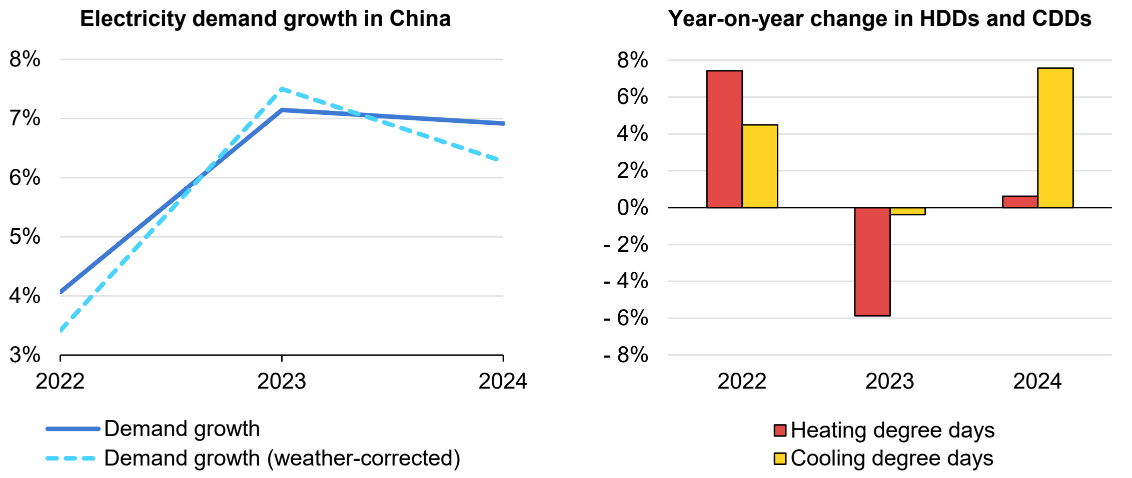
vehicles (BEVs). NEVs accounted for about 9% of total vehicle ownership, up from 3% in 2021. In 2024 alone, over 11 million new NEVs were registered, a 51% increase compared with 2023.

Weather impacts notable in recent years, but played a limited role compared to other factors

In recent years, China has experienced severe heatwaves in the summer months, which have led to increased cooling needs and a corresponding rise in power demand. In 2024, China recorded its hottest July and August in more than six decades. For full-year 2024, the number of cooling degree days (CDDs) was 8% higher than in 2023 and 14% higher than the 2017-2021 average. The years 2022 and 2023 were also characterised by intense heatwaves, and both had a 6% rise in CDDs over the average in 2017-2021.

A significant portion of the increase in Chinese electricity demand in recent years have been attributed to higher cooling demand. It is important here to try to isolate the individual effects of weather from increasing AC ownership. Although it is possible that the recent heatwaves have prompted more people to buy air conditioners, we consider the weather effect here only as an impact of a higher number of CDDs, assuming that the stock of air conditioners remains unchanged from the previous year of comparison.

Year-on-year growth rates of electricity demand (left), and heating and cooling degree days in China (right), 2022-2024



Note: Weather correction is done with respect to previous year. For example, for 2024, this means what electricity demand growth would have been if the weather was the same as in 2023.

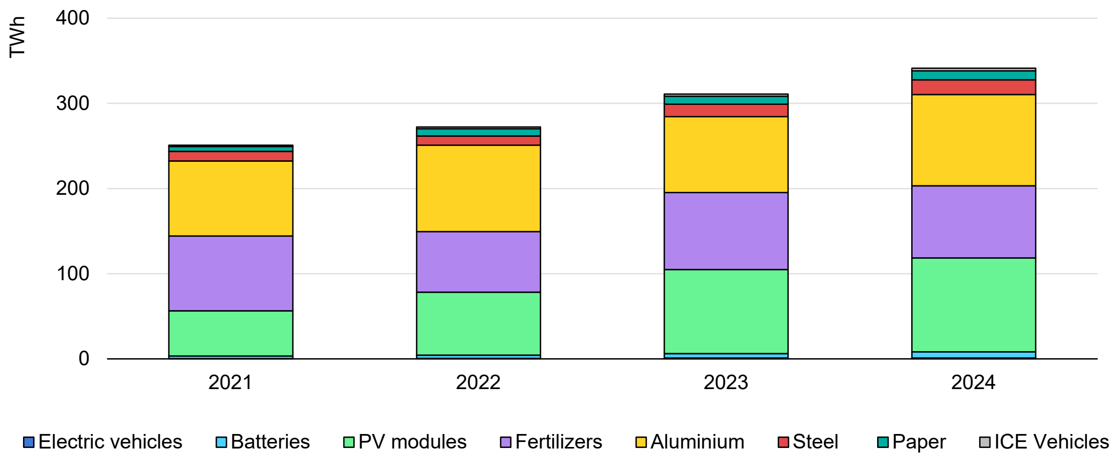
Source: IEA analysis based on data from IEA World Energy Balances (2024), IEA Weather for Energy Tracker (2024), National Bureau of Statistics of China (2024), China Power (2025).

In addition to demand for cooling, by also considering the year-on-year change in heating degree days and the demand for electric heating, we get the following results: If the weather in 2024 had been the same as in 2023, total electricity demand would have been 0.6 percentage points lower in 2024. In 2023 it would have been actually 0.4 percentage points higher and in 2022 again 0.7 percentage points lower. As a result, for the years 2022 and 2024, in which the overall impact of the weather was significant, slightly less than 10% of the increase in demand in both years can be attributed to the weather. These results confirm that although weather had a significant impact in the demand increase, particularly in 2022 and 2024, it played a limited role compared to other factors.

How much electricity does China export in the form of energy-intensive products?

To get a complete picture of the drivers of growth in Chinese electricity demand, it is important to consider China's exports of energy-intensive goods in the form of products manufactured in the country. We estimate that China exports around 340 TWh of electricity indirectly in the form of fertilisers, aluminium, steel, paper, internal combustion engine (ICE) vehicles and new energy products such as PV modules, batteries and EVs. This 340 TWh corresponds to about 6% of Chinese industrial electricity demand in 2024. A substantial portion of this is exported in the form of new energy products, totalling about 120 TWh – more than the annual electricity consumption of the Netherlands. This value excludes electricity consumption from associated upstream processes.

Estimated indirect electricity exports of China in the form of selected goods, 2021-2024

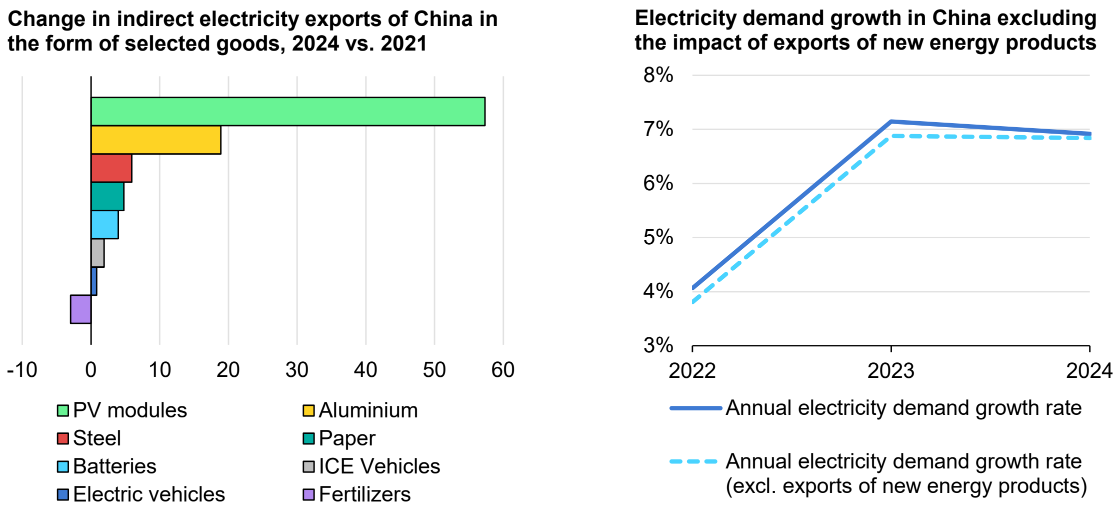


Note: The analysis is based on the electricity-intensity of the production of the selected goods in China. It only considers electricity consumption during the production of the selected goods and excludes the consumption from upstream processes.
Source: IEA analysis based on data from National Bureau of Statistics of China (2024).

New energy products are responsible for most of the increase in indirect electricity exports of the considered goods in this analysis. The electricity required for the manufacturing processes for exports of solar PV modules, batteries and EVs are 60 TWh higher in 2024 compared to 2021. PV modules alone make up almost 92% of this increase, exports of lithium batteries around 6% and the remainder EVs.

Industrial electricity demand in China is estimated to be 700 TWh higher in 2024 compared to 2021. With 60 TWh of indirect demand, exports of new energy products made up about 9% of this increase. Similarly, of the total growth in electricity demand between 2021 and 2024, 4% is attributable to the export of new energy products. Again, indicating that the increasing exports of new energy products and the electricity consumption associated with their manufacturing is only one of the many drivers contributing to elevated demand growth.

Change in indirect electricity exports of China in the form of selected goods, 2024 vs. 2021



Note: The analysis considers only the electricity consumption during manufacturing and excludes the upstream processes.
Source: IEA analysis based on data from National Bureau of Statistics of China (2024).

Understanding China's data centre and 5G electricity consumption projections

Energy consumption of data centres received considerable attention in 2024, especially with the recent AI boom. International organisations, researchers, industry organisations, analysts, consultancies and investment banks have published historical estimates and future projections for data centres on a global scale as well as for individual countries and regions. Trends in the United States, and to a certain extent Europe, have been covered extensively, but developments in China have received relatively less attention outside of the country. Given the rapid digitalisation of China's economy and its AI ambitions, understanding recent trends in the data centre sector and its future growth potential is imperative.

Future projections of data centre electricity demand in China show a high range of uncertainty

There is considerable uncertainty over the electricity consumption needs of data centres in other regions, but none more so than in China. Estimates provided by the limited number of sources coming from the country show that data centres may have consumed as little as 77 TWh or as much as 270 TWh in 2022. The most recent official figures provided by the Chinese Electronics Standardisation Institute (2022) provided an estimate for 2021 at 217 TWh. There are also various unofficial sources citing consumption of 270 TWh in 2022. It should be noted that these numbers on the upper range possibly include not only data centres but also the electricity consumption of data transmission networks, most notably 5G.

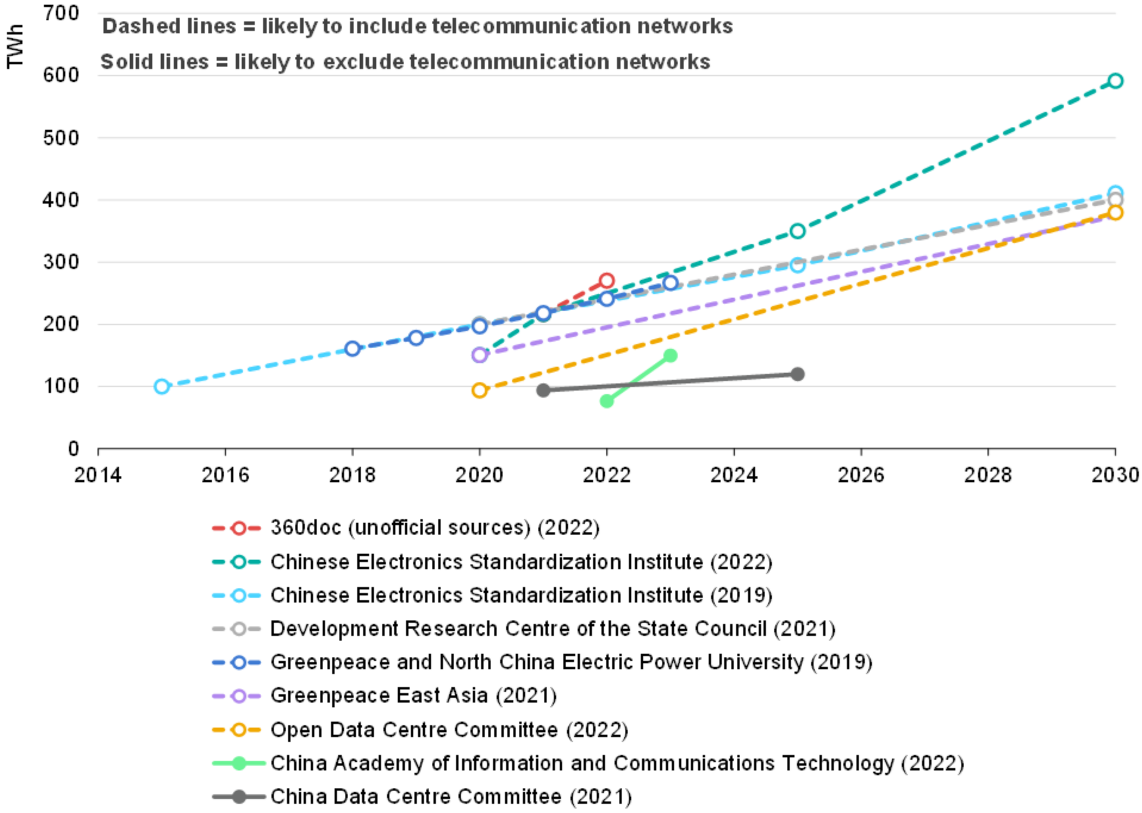
There is even greater uncertainty regarding future electricity consumption of data centres in China. In 2021, the Development Research Centre of the State Council projected that data centres in China would consume 400 TWh of electricity by 2030, while a 2022 projection from the Chinese Electronics Standardisation Institute (2022) indicates a 50% higher figure of around 600 TWh (both sources possibly including 5G and other networks as well). Furthermore, in its China Power Industry Annual Development Report 2024[2], the China Electricity Council assumes that the combined electricity consumption of data centres and 5G base stations will reach 1 200 TWh in 2030, although it does not provide disaggregated figures for data centres and 5G.

While some studies clearly indicate whether they include or exclude data networks in their estimates, many of the published estimates are not clear on their scope of analysis or other methodological details. Based on our analysis of published company-level disclosures on energy use, it appears likely that many studies also include the electricity consumption of networks in their energy estimates. Therefore, in order to identify trends for data centres correctly, it is important to separately understand the electricity consumption trends of networks.

Based on the electricity use data published by China's largest telecommunication operators, including China Mobile, China Telecom, China Unicom, we estimate that telecommunication networks in China consumed 90-110 TWh in 2023, with our central estimate being 100 TWh[3]. This total includes mobile networks (3G, 4G, and 5G) as well as fixed access and core networks. We estimate 5G networks consumed around 30 TWh and 3G/4G around 35 TWh in 2023[4], with the rest from fixed and core networks.

[2] The full report is available as a physical document but only the executive summary is published online.
[3] These estimates exclude electricity used by telecommunication operators in their data centres, offices, stores, and vehicle fleets.
[4] Estimated based on the official number of mobile base stations reported by the Ministry of Industry and Information Technology (MIIT) and typical power consumption characteristics by base station generation (3G, 4G, 5G).

Electricity demand projections for the data centre sector in China from multiple sources, possibly including telecommunication networks, 2015-2030



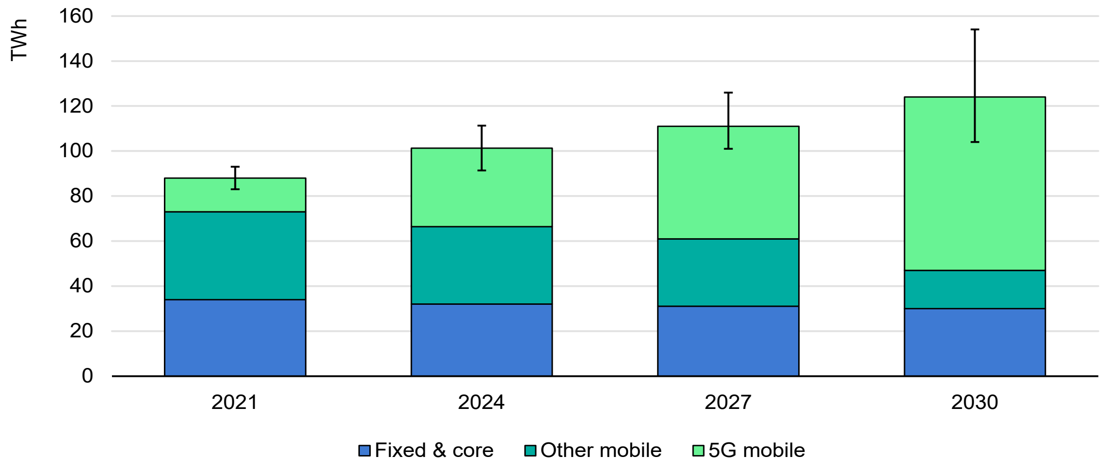
Note: Some of the sources very likely include electricity demand numbers for telecommunication networks in addition to data centres. These are plotted in dashed lines.

Sources: IEA analysis based on estimates and projections shared by 360doc (2022), Open Data Centre Committee (2022), China Academy of Information and Communications Technology (2022), Chinese Electronics Standardization Institute (2022), Greenpeace East Asia (2021), Development Research Centre of the State Council (2021), Chinese Electronics Standardization Institute (2019), China Data Centre Committee (2021), Greenpeace and North China Electric Power University study (2019).

5G networks have been growing rapidly in China. As of January 2025, China reportedly had 4.25 million 5G base stations, up from 1.4 million in 2021 and zero in 2018. The number of 5G telecommunication users in China is reported to have exceeded 1 billion and the population penetration rate was above 71%. The number of private industrial 5G networks was stated a year earlier to be 29 000, with the penetration rate of 5G in large industrial enterprises reaching 37%.

We project that electricity consumption of telecommunication networks could reach 110 TWh in 2027 and around 125 TWh by 2030, driven by continued growth in 5G network energy use. Energy use from 4G is expected to remain flat and begin to decline, while any remaining 2G and 3G networks are expected to be phased out. Nevertheless, the period beyond 2027 in our projection is associated with greater uncertainties regarding 5G trends, particularly regarding the uptake of Internet of Things (IoT) devices and autonomous vehicles as well as the scale of industrial private 5G networks – all of which can impact mobile traffic and connections and consequently electricity demand for 5G networks.

Assumed electricity demand trajectory for telecommunication networks in China, 2021-2030



Note: Error bars indicate range of estimates.

We estimate the electricity consumption of data centres in China, excluding telecommunication networks, at between 70-130 TWh in 2023. Our analysis relies on a combination of data centre energy estimates derived from total company-wide electricity consumption reported by most of the largest Chinese ICT companies with data centres[5] and our modelling that uses bottom-up data of hardware shipments[6]. The wide range of uncertainty is driven by multiple factors. One aspect is the scale of enterprise data centres in the top-down approach, which needs to be additionally assessed and included on top of the company-level estimates which focus only on large data centre operators. Another aspect is that government data centres and supercomputers owned by government institutions are not included in the company-level data. In addition, a major source of uncertainty in bottom-up modelling is the utilisation rates of the data centres, which can vary significantly.

Of the Chinese estimates we have considered above, only the numbers provided by China Data Centre Committee (2021) and the China Academy of Information and Communications Technology (2022) are around 100-150 TWh in 2023, and partly align with our range of estimates, hence they likely focus on data centres

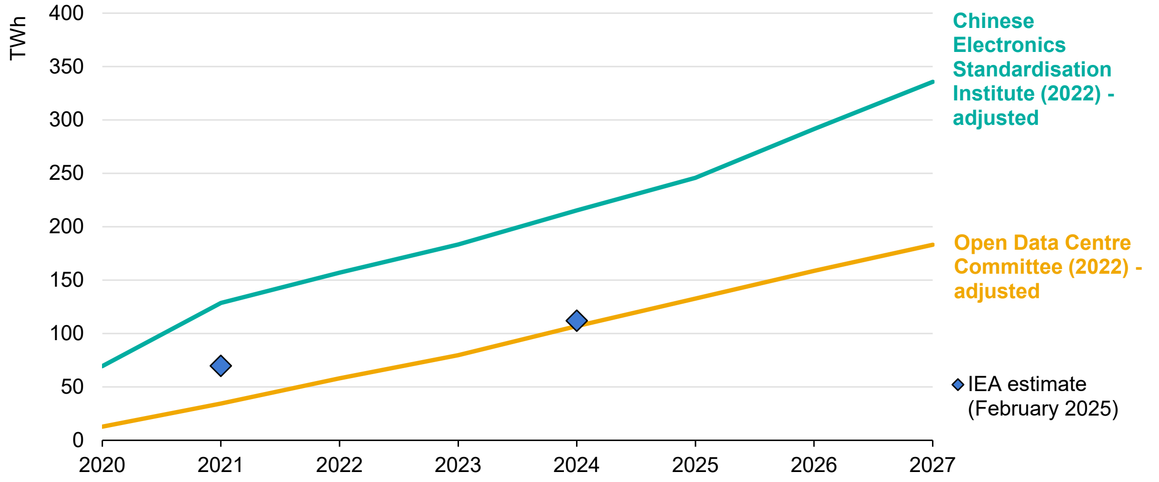
[5] These companies include telecommunication operators with data centre operations (China Mobile, China Telecom, China Unicom), colocation data centre operators (including GDS, Chindata, VNET), as well as tech companies with cloud and hyperscale data centres (including Alibaba, Tencent, Baidu, and Huawei).

[6] This bottom-up modelling approach is similar to that used by Shehabi et al. in their 2024 report for the US Department of Energy. It is based on IT equipment shipment data and the operating characteristics of the IT equipment stock, as informed by both literature and commercial sources. Infrastructure and cooling energy requirements are subsequently modelled to estimate overall data centre energy demand.

and exclude network energy use. For all other sources we have plotted that are in the 200-300 TWh range in 2023, we assume that they likely include electricity consumption of data centres as well as data networks.

If we subtract our assumed trajectory for the electricity demand of networks from the Chinese projections mentioned above that extend to 2030, we arrive at a range of 180-340 TWh for the electricity consumption of data centres in 2027 and 260-470 TWh in 2030. By contrast, the most recent projection provided by China Electricity Council (2024) of 1 200 TWh by 2030, when adjusted for networks, is estimated at around 1 000 TWh for data centres – although it is possible that their projection includes a stronger growth rate for 5G, so the amount for data centres could be less in that case.

Electricity demand projections for data centres in China based on available sources, adjusted to exclude demand from networks, 2020-2027



Note: IEA estimates are based on a combination of data centre energy estimates derived from total company-wide electricity consumption reported by most of the largest Chinese ICT companies with data centres and IEA modelling that uses bottom-up data of hardware shipments. Projections from China are adjusted to exclude telecommunication networks.
Sources: Chinese Electronics Standardization Institute (2022), Open Data Centre Committee (2022).

Similar to many other regions, the uncertainty in China's data centre trends rises substantially when looking further out to 2030 and beyond. In addition to major unknowns such as the demand for AI applications in the economy and the pace of efficiency improvements, the scale of the deployment of AI accelerator chips and their capabilities will also be important factors, especially when considering recent US sanctions on exports of newer generation of AI chips to China. The country's latest 14th Five-Year Plan, published in 2021, highlighted high-end chip design as one of the key digital technologies to be considered for innovation and application. China also has plans to increase computing power in the country through various schemes, such as its Eastern Data and Western Computing Initiative.

China has ambitious plans to increase computing power via its Eastern Data and Western Computing initiative

China's government initiatives aim to increase computing power domestically and significant investments have been undertaken accordingly, although it should be noted that this does not directly correspond to an increase in electricity consumption as this depends on a number of variables, which are discussed in more detail in the following section. In recent years, China has invested around USD 6 billion in national computing data centre projects within the Eastern Data and Western Computing (EDWC) strategy. The EDWC, first proposed in 2021, aims to distribute computing operations across regions: in the western and northern regions with abundant renewable energy, data centres mainly for high-latency services such as AI training and storage will be deployed; in the eastern and central regions, data centres for low-latency, load-based services such as AI reasoning and intelligent networking will be deployed. Up until June 2024, under the EDWC, 1.95 million server racks have been installed, of which 63% are reported to be currently in use. For comparison, the country had over 8.1 million data centre racks in operation by the end of 2023. Recent reports suggested that computing power expanded to 246 EFLOPS as of June 2024.

Action plans launched in 2023-2024 to improve computational power, efficiency and clean energy share

In 2023, to support the country's aims for growth in computing power more broadly, the Action Plan for High-Quality Development of Computational Power Infrastructure set a series of goals on computing power, network power, storage power and application scenarios. Specifically, the scale of China's computing power is targeted to exceed 300 EFLOPS by 2025, with the proportion of intelligent computing power reaching over a third of the total computing power. For network power, the plan set three sub-targets on latency, optical transmission network (OTN) coverage, and the usage of innovative technologies. Theoretical latency is targeted to be no greater than 1.5 times the direct network transmission for national data centre clusters, less than 5ms between important computing infrastructure within national hub nodes, and below 1ms between key infrastructure in urban areas. The action plan aims to achieve an OTN coverage rate of 80% in key application areas and to increase the usage of innovative technologies such as RFID, IPv6 and SRv6 to 40%. The plan also set a target for China's total storage power to exceed 1 800 EB, with advanced storage power accounting for over one-third, and to achieve total disaster recovery coverage for key industry core data and other crucial data.

China aims to not only achieve growth in computing power but also efficiency improvements. According to the Special Action Plan for Green and Low-Carbon Development of Data Centres (2024), China has set objectives to reduce the average Power Usage Effectiveness (PUE)[7] of data centres to below 1.5, improve the average Water Usage Effectiveness (WUE) and Carbon Usage Effectiveness (CUE) and to increase the overall on-load rate to no less than 60% by the end of 2025. Similarly, the 2024 Action Plan included goals to increase the share of clean energy in data centres' electricity consumption, setting targets for the overall utilisation rate of renewable energy to increase by 10% annually for data centres and for EDWC data centres to source at least 80% of their electricity consumption from renewables by 2025.

Strong growth in peak electricity load in India amid economic growth and rising AC usage

Following a strong 8.3% increase in 2023, electricity demand in **India** grew 5.8% y-o-y in 2024 amid strong economic growth. While electricity consumption rose by a robust 8.5% during the first half of the year due to intense and long heatwaves, the second half saw a more subdued growth in demand amid milder weather. Supported by rapid economic expansion and increasing electrification, India's electricity demand is forecast to grow at a high rate of 6.3% annually from 2025 to 2027 on average. Rising air conditioner ownership will continue to bolster electricity demand growth.

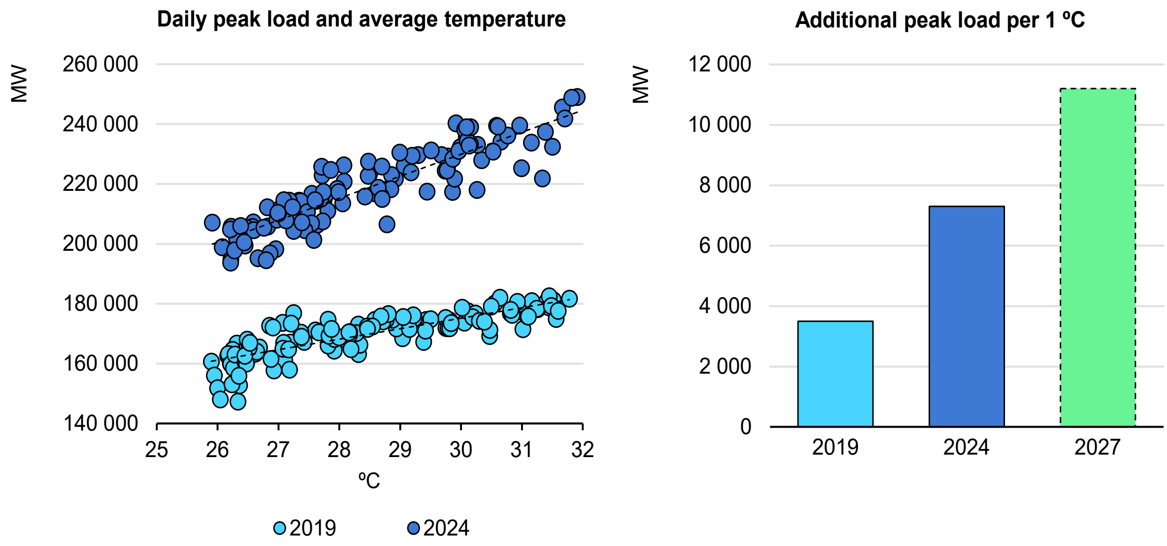
Peak electricity load in India has shown strong growth in recent years, rising from 148 GW in 2014 to 250 GW (+68%) in 2024, led higher by the rapid expansion of its industry, development of agriculture, enhanced electricity access and increased use of air conditioning and appliances in the residential and commercial sectors. As a result, electricity demand in these sectors rose by around 60-65% between 2014 and 2024. While good interconnections among states and the operation of thermal power plants allow Indian utilities to cover demand in energy terms throughout the year, the rapid increase in yearly peak load poses a major challenge for the electricity grid and national authorities.

Even though less than 20% of households in India are equipped with an air conditioner, the contribution of cooling to total peak load is estimated at 60 GW in 2024, as sales reached a new record of 14 million AC units sold in 2024. This is 27% more than in 2023, when 11 million units were sold. By 2030, cooling equipment is expected to contribute one-third to the peak electricity load in India, potentially reaching 140 GW. This would be more in line with trends in advanced

[7] PUE is the ratio of the total power used in the facility with the power consumed by the IT equipment. The overall efficiency improves as the ratio decreases towards 1.0.

economies such as the United States, where cooling demand currently takes 50% of total peak load on the warmest days in Texas. Data shows that for each incremental degree in daily average temperature, daily peak demand in India increased by more than 7 GW in 2024, twice the increase observed in 2019. By 2027, this value could surpass 11 GW per degree.

Daily peak load in cooling season compared to average temperature in India, 2019-2027



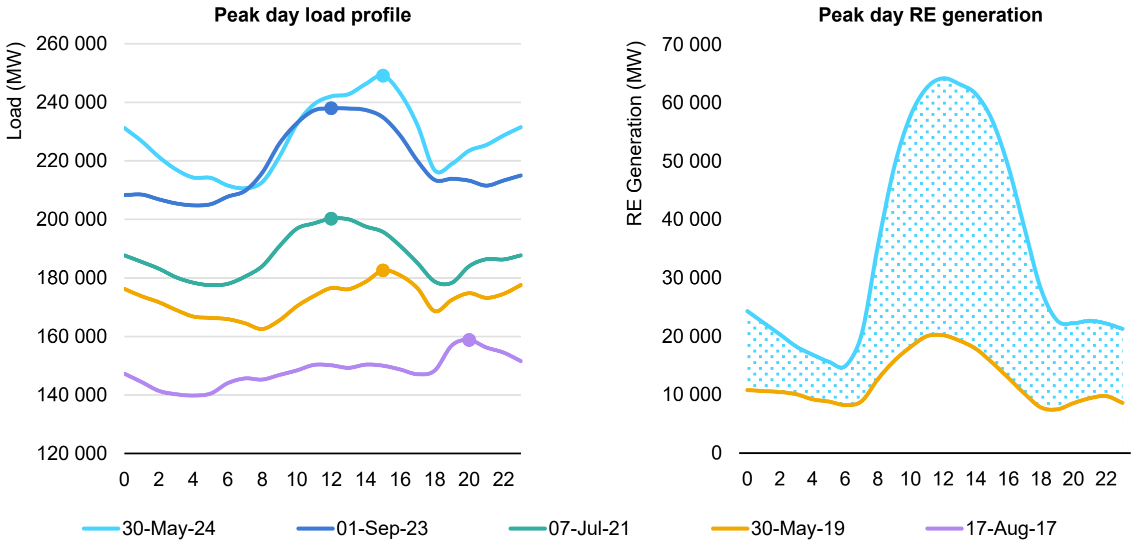
Notes: For the 2027 estimation, historical values of 2017-2024 were used and 2030 was estimated based on the contribution of cooling to peak load in 2030 as published in the IEA World Energy Outlook 2023. Data for 2027 is obtained from the trendline connecting these data points.

Source: IEA analysis based on data from IEA Real-Time Electricity Tracker (2024), IEA Weather for Energy Tracker (2024), IEA World Energy Outlook (2023).

Time-of-day tariffs prove successful in shifting the evening peak load to midday, when solar is abundant

The use of electricity in agriculture is important in India due to farmers' growing dependence on power to operate irrigation pumps. In Rajasthan, agricultural demand makes up around 40% of the total statewise. In the past, farmers would activate water pumps at night only, as agricultural feeders provided free or cheap electricity at that time. Other farmers rely on diesel-fuelled pumps, which are more expensive to operate and polluting. Until 2019, average load was typically higher in the evening due to increased demand in agriculture and residential sectors between 7:00 and 8:00.

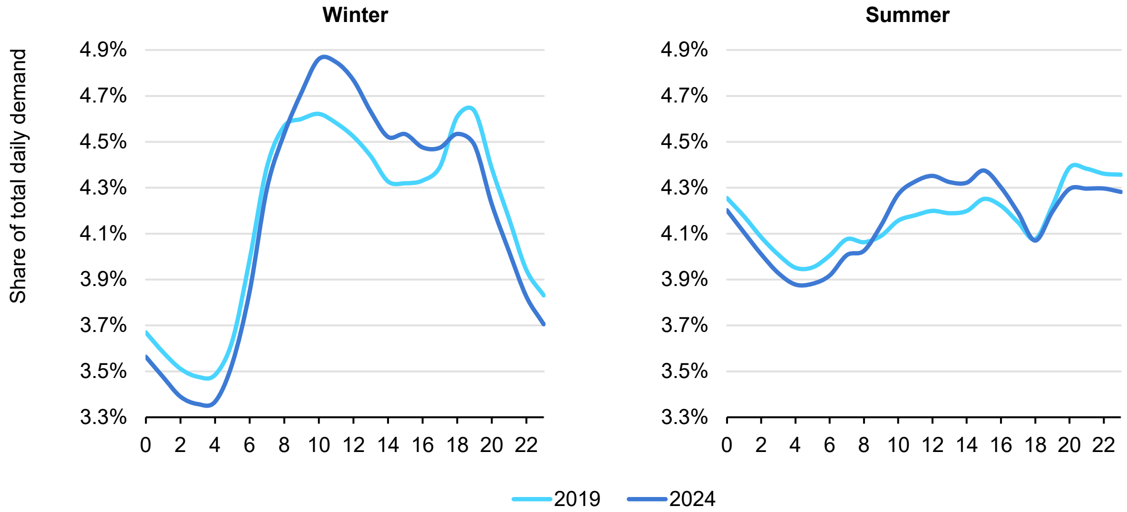
Load profile and renewable generation (excluding large hydro) on yearly peak-load days in India, 2017-2024



Note: Renewable energy generation includes wind, solar, biomass, bagasse, small hydro and other renewables.
Source: IEA analysis based on data from IEA Real-Time Electricity Tracker (2024), NITI Aayog (2024).

Forecasting growth in yearly peak load, and considering the variable renewable energy (VRE) capacity additions in recent years, India launched the PM-KUSUM Scheme in March 2019, a successful agricultural demand shifting programme which, among other things, subsidises the installation of solar pumps, incentivises the connection of distributed solar PV to agricultural feeders (therefore supplying electricity at daytime hours) and provides a favourable framework for the installation of large solar PV plants in agricultural areas. Five years later, and with PM-KUSUM scaled up in January 2024, hourly demand data shows that this scheme has transformed the average load profile in India, shifting a large portion of the evening peak to midday, when VRE generation is the highest. It has also limited the growth in diesel oil consumption in the agricultural sector, by electrifying this end use.

Average daily electricity load profile in selected months, 2019-2024



IEA. CC BY 4.0.

Note: Winter includes November to January, summer includes June to August.
Source: IEA analysis based on data from IEA Real-Time Electricity Tracker (2024).

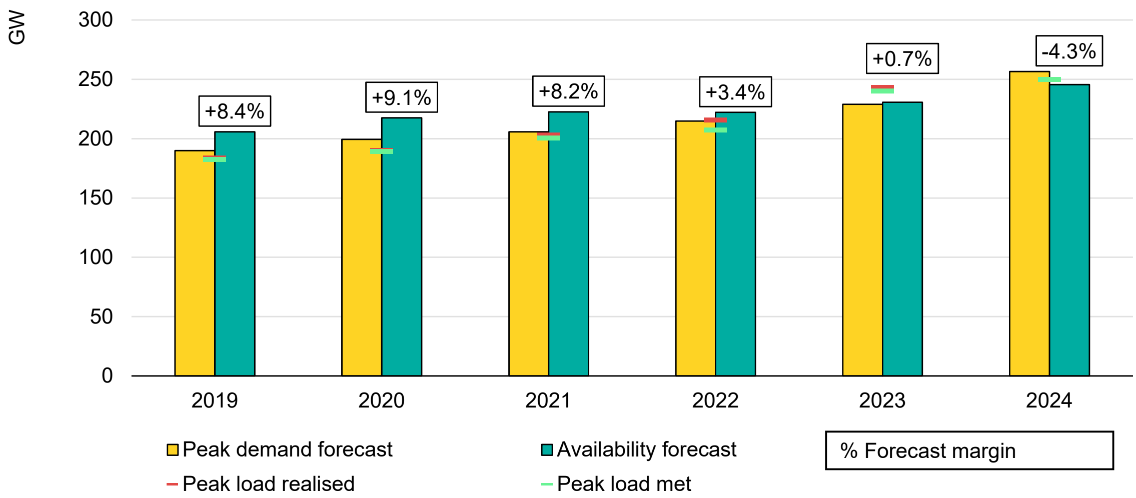
Static Time of Day (ToD) tariffs applicable to industrial, commercial and public services consumers have also contributed to a reduction in the evening peak, as prices are higher between 6:00 and 10:00 than the rest of the day in practically all states. In August 2023, the Ministry of Power published the Implementation of Time of Day Electricity Tariff System, which established a rate reduction of at least 20% compared to normal tariffs during solar hours and a rate increase of at least 20% during the peak period of the day. The Ministry made ToD tariffs mandatory for all medium to large commercial and industrial consumers as of 1 April 2024, while smaller consumers (under 10 kW) will only be affected as of 1 April 2025. The current ongoing rollout of smart meters should allow suppliers to offer dynamic tariffs as well as the extension of ToD tariffs to residential consumers.

Through these policies and tariffs, the Indian government aims at further shifting load from the evening to daytime, as the expansion of solar PV in the coming years will have a very limited effect on meeting the ever-growing evening peak if it is not coupled with storage deployment.

Exceptional measures were taken in 2024 to ensure available capacity kept pace with peak load growth

The India Energy & Climate Centre (IECC) recently estimated that 20-40 GW evening power shortages are likely by 2027 even if all planned dispatchable capacity is commissioned on time. According to the National Electricity Plan 2023-2032 published by the Ministry of Power, the peak demand is forecasted to reach 458 GW in 2032, 83% higher than in 2024. However, a shortfall in available capacity is already a pressing issue for Indian stakeholders, with data from the Load generation balance report of the Central Electricity Authority (CEA) showing that the available capacity at the time of yearly peak load was forecasted to be 11 GW lower than peak load levels (-4.3%) in 2024, after several years of decline of the forecast margin. Adequacy was the most critical in the northern and eastern regions of India, where the deficit in power requirements reached -7.3% and -7.9%, respectively, despite available capacity growing by 6.6 GW and 1.3 GW, respectively, in one year.

Evolution of the forecasts for peak load, availability and margin of the Indian Central Electricity Authority vs. the realised and met peak load, 2019-2024



Source: IEA analysis based on data from Central Electricity Authority (2024).

To manage the forecasted shortfall in power requirements in 2024, the CEA issued specific measures to be taken during the year, such as continued generation support for imported coal-based plants (resulting in up to additional 17 GW) and gas-fired power plants (up to additional 13 GW), minimisation of planned maintenance during high demand periods, and minimisation of partial and forced outages (up to additional 10 GW). These measures were successful in ramping up available capacity as the peak load of 250 GW was met on 30 May 2024, although the realised peak load was 6.6 GW lower than forecasted.

Electricity demand in the United States rebounds to new record in 2024

In the United States, the world's second-largest electricity consumer after China, demand growth rebounded to 2% in 2024, following a 1.8% decline in 2023 amid mild weather. While demand from the buildings sector saw strong growth, industrial sector also had significantly higher electricity consumption. Hot summer temperatures in 2024 provided an additional boost to demand growth due to higher cooling needs. In 2024, electricity demand surpassed its previous high in 2022.

We expect US electricity demand to grow at an average annual rate of about 2% over the period 2025-2027.[8] This is an upwards revision from our forecast in January 2024, which had projected 1% growth for the 2025-2026 period. With this revision, forecast US electricity demand in 2026 is now around 100 TWh higher than in our previous forecast a year ago.

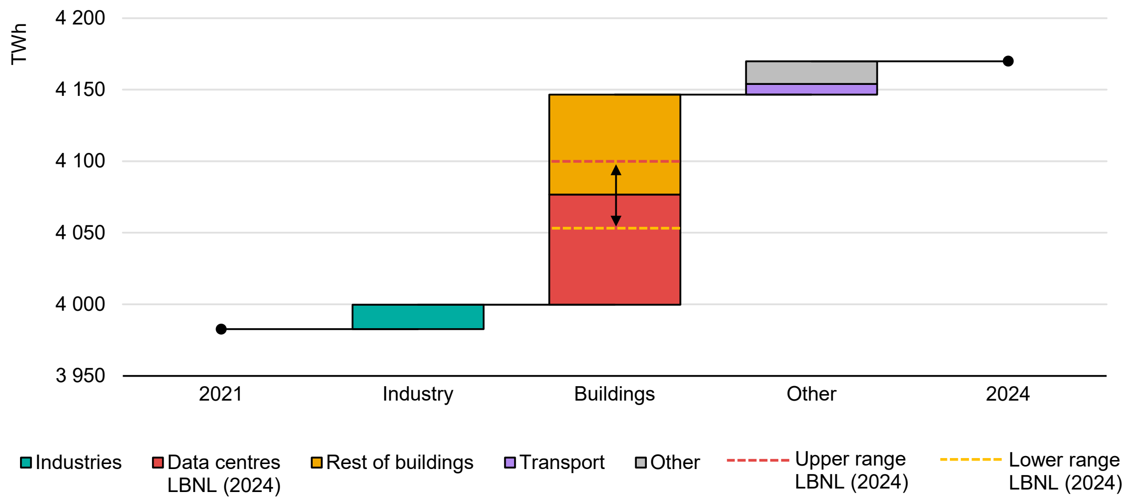
One major reason for the upward revision is the expectation of strong demand growth from the data centre sector. The other factor is the robust economic outlook, with the IMF having revised the 2025 GDP growth rate in their latest October 2024 outlook significantly higher from 1.8% to 2.2%.[9] Overall, the latest IMF outlook projects robust economic growth for the United States over the 2025-2027 period, with annual GDP averaging 2.1%. We expect the manufacturing sector in general, especially new large industrial loads such as semiconductor production facilities, to contribute to the demand growth through 2027. This will be accompanied by continued electrification of the heating and transportation sectors.

Data centres are a key driver of electricity demand growth in the United States

The rapid expansion of data centres in the United States has positioned the sector as a major catalyst of electricity demand growth, which will have a substantial impact on the country's energy landscape. A recent study commissioned by the U.S. Department of Energy highlights the strong growth in electricity consumption by data centres, which rose from about 60 TWh in 2014 to 176 TWh in 2023, and constituted more than 4% of the country's total electricity use. Their scenarios indicate this consumption could rise by an additional 150 TWh to 400 TWh by 2028, reaching about 325 TWh to 580 TWh, and accounting for 6.7% to 12% of total US electricity demand. The growth trend is supported by the record pace of new data centre announcements. In the first half of 2024 alone, announced data centre projects were associated with nearly 24 GW of power capacity needs – triple the amount stated during the same period in 2023.

[8] The forecast is made based on the policy framework as of December 2024.
[9] Similarly, the GDP growth rate in 2024 for the US economy is revised by the IMF to 2.8%, up from 1.5% in the previous IMF October 2023 outlook.

Estimated drivers of change in electricity demand in the United States, 2024 vs. 2021



Notes: The numbers correspond to net electricity demand. Buildings include residential and commercial sectors. Data for 2024 are preliminary.
Source: Data centre sector electricity consumption ranges are based on the official US study from LBNL (2024) commissioned by the U.S. Department of Energy. As a baseline, mean of the ranges provided in the study is assumed and the ranges across their scenarios are shown with arrows and dashed lines.

States where computing facilities are expanding rapidly are showing higher electricity demand growth rates above the national average. According to the Energy Information Administration (EIA), commercial electricity demand has grown the fastest in states hosting clusters of computing facilities. Between 2019 and 2023, the ten states with the most rapid demand growth added 42 TWh in total – a 10% increase over the four-year period. Electricity demand has increased the most in Virginia, which added 14 TWh, followed closely behind by Texas with about 13 TWh. By contrast, demand across the other 40 states reportedly declined by 28 TWh (a 3% decrease) during the same period.

Northern Virginia has emerged as a major hub for data centres, with 94 new facilities and over 4 GW of capacity connected since 2019. Virginia is by far the state with the highest share of electricity demand coming from data centres at more than 25%. According to a report by a consulting firm, an anticipated 11 GW of additional data centres in Northern Virginia by 2030 would account for more than 40% of the state's current peak electricity demand.

New large industrial loads and electrification of heating and transportation will also support demand growth

The second largest source of electricity demand growth in terms of TWh, after data centres, is the industrial sector. After a contraction in 2023, US manufacturing activity increased in 2024 over 2023 levels. US industries overall enjoy a more competitive position based on lower energy prices compared to many other regions. New industries with large loads such as semiconductor production and battery manufacturing are expected to emerge over the forecast horizon as additional sources of electricity demand.

The pace of electrification of the US heating sector moderated from late 2022 to early 2024, though over our forecast period we expect continued growth. Heat pump sales in the United States rose on average annually by 11% in 2017-2022. After a substantial decrease of 17% in 2023, the sale of air-source heat pumps rebounded by 14% y-o-y in January-November 2024, particularly in the second half of the year. Despite the recent slowdown, heat pumps continue to make up a higher share of home heating sales since 2021, accounting for 21% more sales than gas furnaces in 2023. We expect continued growth in heat pump sales through 2027.

Electrification of transportation has progressed at a significant pace over the last five years in the United States, with the share of electric cars rising from a mere 2% in 2019 to 10% in 2024. However, a relative slowdown in growth was observed in 2024, even though the absolute numbers increased. In 2024, the number of EVs sold in the United States increased by about 10% y-o-y, moderating significantly from the 40% growth observed in 2023. Of the 1.6 million plug-in electric vehicle (PEV) sales in 2024, about 80% were battery electric vehicles (BEVs) and 20% plug-in hybrid vehicles (PHEVs).

Electricity demand and peak load projections are revised upward across the United States

Regional transmission organisation PJM, that manages the electric grid for a large part of the US Mid-Atlantic and Midwest, published in January 2024 its long-term load forecast where they expect an average 2.4% annual growth for net demand over the next ten years, significantly higher than their forecast of 1.4% a year earlier. The reasons for the higher electricity demand growth in the PJM region, which includes the fastest growing data hub state Virginia, are due to the rapid development of data centres, combined with the accelerating electrification of transportation and industry.

The latest edition of the Western Assessment of Resource Adequacy report published in December 2024 forecasts a significant increase in electricity demand across the US Western Interconnection over the next decade, double the growth projected for the same period in the resource plans filed in 2022. The report indicates that this sharp upward revision is largely driven by the anticipated development of large load facilities in various parts of the Western region. These figures correspond to about 2% annual average growth rate for electricity demand in the Western Interconnection area as a whole, and around 3% for the Desert Southwest region, which comprises all of Arizona, most of New Mexico, and parts of Texas and California.

The Electric Reliability Council of Texas (ERCOT), in the July 2024 update of their Long-Term Demand and Energy Forecast, expects strong growth in electricity demand over the next decade. The updated forecast takes into account additional contractually agreed loads and includes “officer letter” loads, which correspond to large loads without a signed contract.[10] ERCOT’s 2024 forecast shows a large increase in expected load growth compared to their 2023 forecast. Key drivers behind this expected surge were stated to be the expansion of data centres, crypto mining facilities, industrial electrification (notably in the oil and gas sector), the development of a hydrogen economy, and the increasing adoption of electric vehicles.

The EIA in their Short-Term Energy Outlook (STEO) published in October 2024 provided a deep dive into electricity demand through 2025 from data centres and cryptocurrency mining in ERCOT, which are included by ERCOT under their “large flexible load (LFL)” consumer category. The EIA estimates that LFL consumption will amount to 54 TWh in 2025, up by almost 60% from their expected demand in 2024. Delays in the large load approval process or in developers’ plans leads to 37 TWh of LFL consumption in their low-growth scenario, whereas an accelerated approval process results in 81 TWh in the high-growth scenario. Assuming other load types do not vary between the scenarios, they project total electricity consumption in ERCOT to increase in 2025 y-o-y by as low as 1% or as high as 10%, with their baseline assumption at 5% growth – an increase from 464 TWh to 487 TWh. For total US electricity consumption in 2025, the STEO January 2025 forecast a 2.1% y-o-y increase, following 1.9% growth in 2024.

In addition to the regions mentioned above, many other planning areas in the United States have also made significant upward revisions to their peak load and electricity consumption forecasts through at least 2029, as summarised and compared in a report by power sector consulting firm Grid Strategies published in December 2024. With an analysis based on FERC Form 714 filings of the planning areas, the study shows that the aggregate electricity consumption forecast for 2029 has been moving upwards since 2023. The aggregate net electricity consumption forecast in 2022 for 2029 was 4 375 TWh. In 2023, this figure was revised upwards significantly, to 4 553 TWh, and in 2024 even more sharply to 4 773 TWh. Assuming the realised net electricity demand for 2024 of 4 090 TWh

[10] In its July 2024 forecast, ERCOT projected its summer peak demand to increase from 85.4 GW in 2023 to 141 GW in 2029. ERCOT presented in September 2024 a sensitivity case to this forecast, where only 50% of the officer letter loads are considered, which reduces the 2029 peak load projection to 129 GW. Our summary in the paragraph is based on the main case that was published in July.

as the baseline, this corresponds to average annual growth of 1.4% for the 2025-2029 period for the aggregate submissions in 2022, and upward revised values of 2.2% for submissions in 2023 and 3.1% in 2024.[11]

The North American Electric Reliability Corporation (NERC), in their Long-term Reliability Assessment published in December 2024, projects US electricity consumption up by 1.7% CAGR over the period 2024-2034. NERC also points out that the summer peak demand forecast is projected to increase by over 132 GW, while the winter peak demand is expected to rise by 149 GW. Growth rates for both peak demand and energy are sharply rising, reversing a nearly 20-year trend of flat or declining growth, with increasing amounts of large commercial and industrial loads, highlighting the expansion in data centres and cryptocurrency mining facilities as important factors.

EU electricity demand is recovering but the pace was slow in 2024

The **European Union**'s electricity consumption fell 2.8% in 2022 y-o-y, which was followed by a 3.3% drop in 2023 – with both declines mainly driven by reduced electricity consumption in the industrial sector as it struggled with economic slowdown and elevated energy prices. As a result of these two consecutive annual declines, EU electricity consumption fell to levels last seen two decades ago. EU electricity demand posted a 1.4% y-o-y increase in 2024. Industrial electricity demand is estimated to have stabilised in 2024, remaining relatively flat compared to 2023. The growth in electricity demand is estimated to have come from the commercial sector boosted by data centres, and residential and transport sectors amid an increasing number of heat pump and EV stocks, respectively.

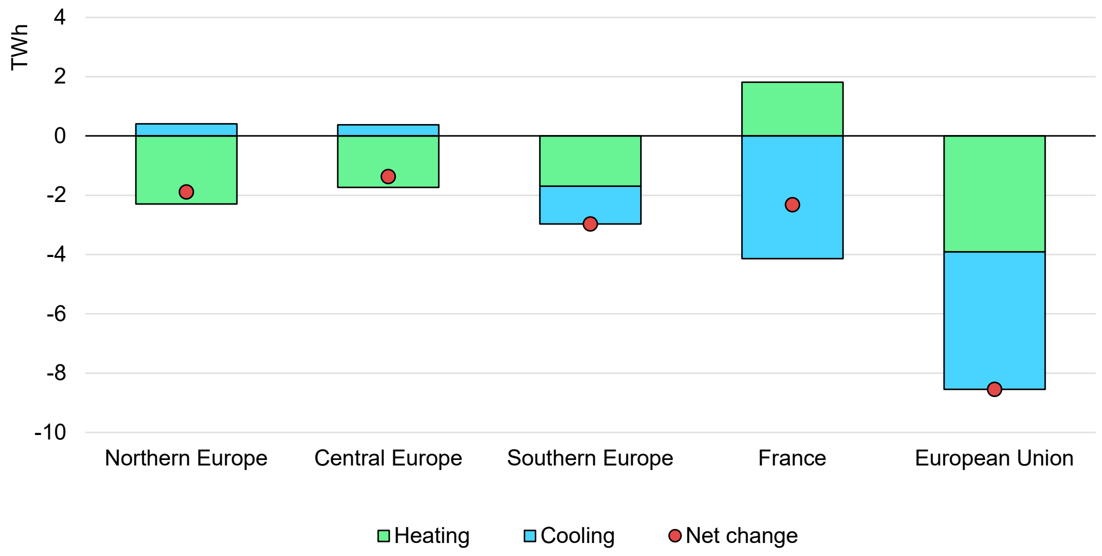
Despite returning back to growth in 2024, we do not expect electricity consumption in the European Union to recover to its 2021 level until at least 2027. We forecast EU electricity demand to grow at an average annual rate of 1.6% in 2025, 1.7% in 2026 and 1.8% in 2027. This is a downward revision from our previous forecast in July 2024, where we projected an annual growth rate of 2.6% for 2025, as well as our earlier January 2024 three-year ahead forecast, which had a slightly higher 2.7% for 2025 and 2.4% in 2026. Both previous forecasts had expected electricity demand growth of 1.8% for 2024 based on the prevailing IMF economic forecasts.

In the European Union as a whole, electricity consumption due to cooling and heating in 2024 was less than in the previous year, which is estimated to have

[11] 2024 baseline consumption values differ across the forecasts of the planning areas as well as over the years the forecasts were made. The growth rates we calculated here are indicative to demonstrate the effect of the upward revisions. These are likely to differ from the growth rates originally considered by the individual planning authorities in their demand projections due to different assumptions for the 2024 value.

resulted in a demand reduction of around 8 TWh. In many parts of the European Union, the heating period in 2024 was milder compared to 2023. France appears as an outlier as it had slightly more heating degree days in 2024 compared to 2023, resulting in more electricity consumption for heating. Similarly, France had 33% less CDDs than in 2023, which in turn resulted in significantly lower electricity consumption for cooling.

Estimated year-on-year weather-related change in electricity consumption for heating and cooling in the European Union in 2024



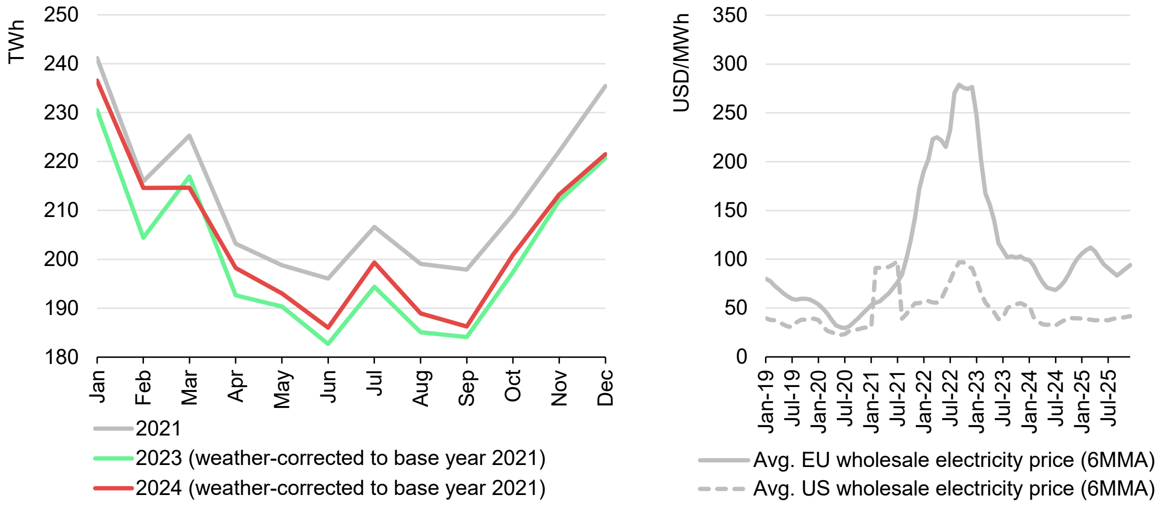
Notes: Southern Europe includes: Bulgaria, Croatia, Cyprus, Greece, Italy, Malta, Portugal, Romania and Spain. Central Europe includes: Austria, Belgium, Czechia, Germany, Hungary, Luxembourg, Netherlands, Poland, Slovak Republic and Slovenia. Northern Europe includes: Denmark, Estonia, Finland, Ireland, Latvia, Lithuania and Sweden. France is shown separately due to the large share of electric heating.

The downward revision is largely due to a weaker macroeconomic outlook for the European Union. In its October 2024 outlook, the IMF projects the EU's GDP growth at 1.6% for 2025, showing a slight recovery from 1.1% in 2024 and 0.6% in 2023, which marked a substantial slowdown. This is a notable downgrade from the IMF October 2023 projections, which estimated GDP growth at 0.7% in 2023, 1.5% in 2024, and 2.1% in 2025. Projections for 2026 and 2027 have also been revised downward – from 2.0% to 1.7% and from 1.8% to 1.6%, respectively.

Weak macroeconomic growth, sluggish domestic demand and export market pressures have slowed the recovery of energy-intensive industries in Europe, with electricity consumption still below pre-crisis levels. While some recovery is related to the resumption of production halted during the 2021-2023 energy price surge, uncertainty remains due to ongoing competitive pressures and sluggish product demand. Energy prices have declined from their peak levels but they remain above pre-Covid levels and are higher than in many other major economies, adding to the challenges faced by industries – factors reflected in our forecast.

Another reason behind the revised forecast is a more cautious outlook for EU electricity consumption from EVs and heat pumps through 2027. Although electrification progressed in 2024, heat pump installations slowed, and EV adoption was weaker than last year. Our forecast assumes these trends will persist in the near term, though declining costs and policy changes could unlock substantial growth.

Monthly EU electricity demand, 2021-2024 (left), and average wholesale electricity prices in the European Union and the United States, 2019-2025 (right)

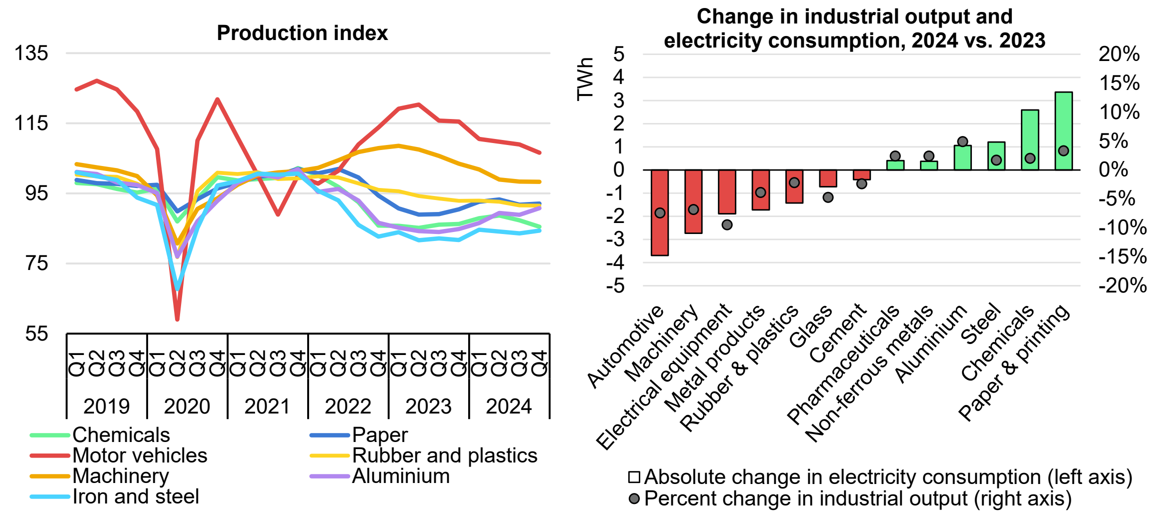


Notes: In the left chart, 2023 and 2024 demand is weather-corrected to the base year of 2021 for comparison purposes. The 2021 demand profile corresponds to the realised net demand. In the right chart, the plotted average wholesale prices are demand-weighted six-month moving averages (6MMA) for the regions. EU average prices for 2025 are based on demand-weighted average futures prices from January 2025. US average prices for 2025 are based on demand-weighted averages of EIA STEO projections from January 2025.
Source: IEA analysis based on data from Eurostat (2024) and EIA (2024).

Slight recovery in primary metals and chemicals, with the automotive sector coming under increasing pressure

EU industrial electricity demand remained roughly flat in 2024, following consecutive declines of about 6% over the previous two years, in 2022 and 2023. While the previous decline trend seems to have stabilised, there is still significant uncertainty surrounding the electricity demand recovery in European industries. Electricity prices remain above pre-crisis levels for energy-intensive industries, which are also higher than in most competing regions. At the same time, domestic demand for many industrial products remains weak. Nevertheless, slight increases in primary metal and chemical production were observed in 2024. The extent of the recovery in these sectors is uncertain, however, as negative business sentiment is prevalent across multiple countries, with many companies experiencing difficulties. In addition to energy-intensive industries, among leading manufacturing sectors, the automotive industry is increasingly coming under pressure from weakening domestic demand and growing competition in export markets. Considering the high relevance of the automotive industry in European industrial supply chains, these difficulties are expanding beyond automakers to the whole supply chain, placing wider portions of the industry at risk.

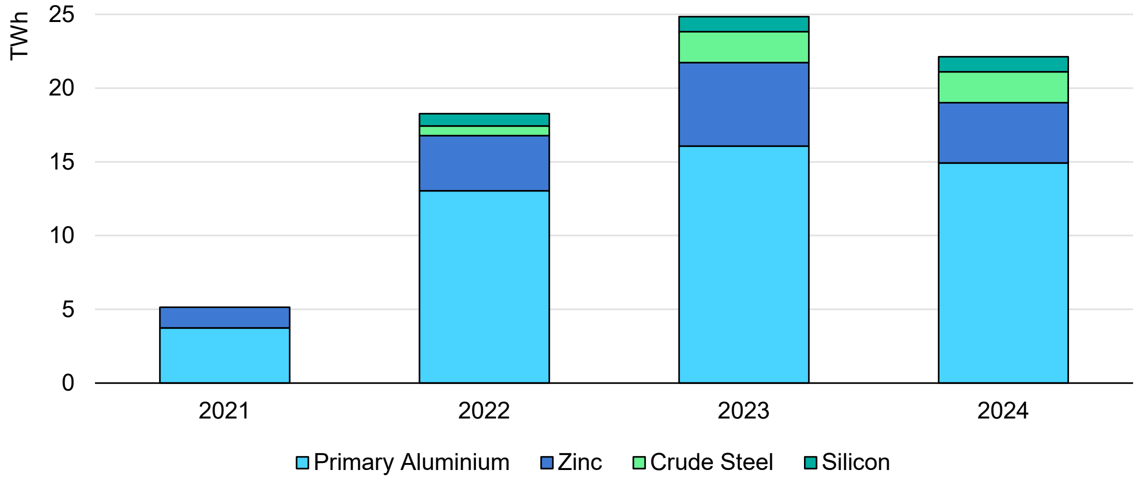
Production indices of selected industries in the European Union, 2019-2024, and electricity consumption trends 2024 vs. 2023



Notes: The data is seasonally and calendar adjusted, with data presented as an index with 2021=100. Data for 2024 includes the period from January to November.
Source: IEA analysis based on data from Eurostat and Cefic.

Among energy-intensive products, European primary **aluminium** production showed tentative signs of recovery, with an estimated 4% y-o-y increase in 2024, however, this is still almost 25% below the levels seen in 2018. Despite overall growth in aluminium production, some producers faced difficulties. In 2024, the Dutch aluminium maker, Aldel, suspended production, citing high energy costs and insufficient government support. Meanwhile, the Norwegian aluminium company Norsk Hydro saw an 18% drop in profits in the second quarter of 2024. However, profits exceeded expectations in the third quarter of 2024, thanks in part to an uptick in aluminium prices.

Estimated cumulative loss in annual electricity demand in selected primary metal industries in the European Union compared to 2020



Notes: Estimates are based on announcements of permanent and indefinite plant closures, and production curtailments. The numbers are to be interpreted as structural demand destruction due to the production losses compared to the reference period 2020. Realised changes in the demand in the year of closure can differ due to the exact timing of the closure within that year. Silicon electricity demand considers silicon metals, silicon manganese, polysilicon and silicon-based alloys.
Source: IEA analysis based on company data, national statistics and news reports.

The **steel** sector in the European Union also saw tentative signs of recovery, with an increase of just over 2.5% y-o-y in production over the 2024 period. However, this followed two years of consecutive declines, which led to crude steel production now at approximately the same level as that seen in 2020. Across the steel sector, lower demand from European industry, increased competition from abroad, rising energy costs and higher interest rates are cited as key reasons behind the challenges facing the sector.

The British industrial and metals company Liberty Steel suspended operations in their Romanian plant before restarting the furnaces when market conditions improved. They are also trying to sell sites in Luxembourg, Italy and Belgium, having closed coke ovens in Hungary. In Czechia, it announced the closure of coke ovens and the halting of iron and steelmaking operations, while its plant in Poland has been declared bankrupt. In the United Kingdom, Tata Steel shut down its final blast furnace at Port Talbot, though it will be replaced by an electric arc furnace, which is set to open in 2028. The Luxembourg-based steel producer Arcelor Mittal announced the closure of two plants in France in 2024. German conglomerate Thyssenkrupp wrote down EUR 1 billion and proposed 5 000 job losses as well as the outsourcing or divestiture of another 6 000 positions.

During the first eleven months of 2024, the average production index for **chemicals** increased by about 2% if compared to the same period in 2023. However, weak demand and high energy prices (when compared to similar sized economies such as the United States or China) have led to declining business confidence. This may also cause delays in projects focusing on electrification and decarbonisation of the sector.

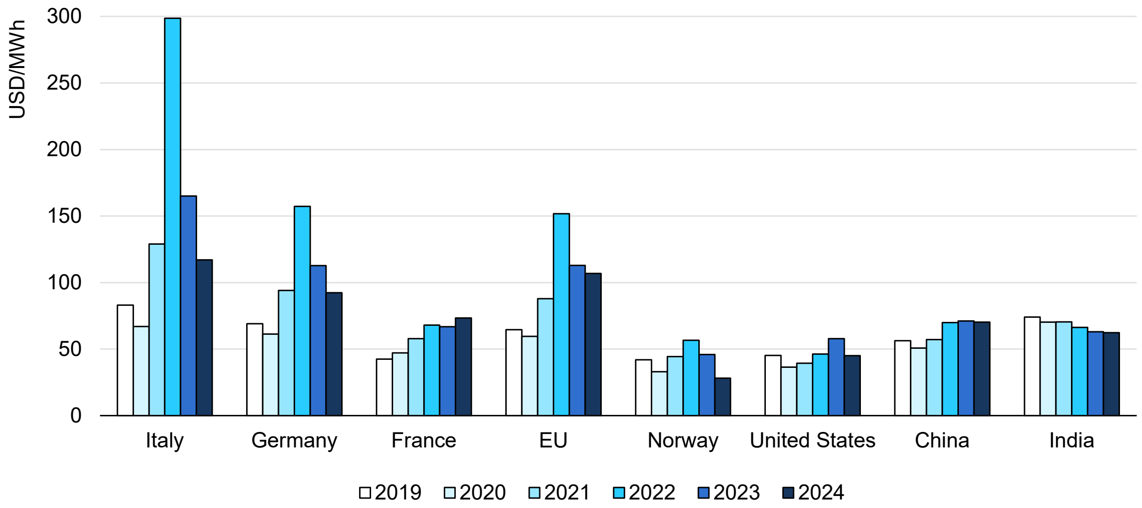
Growing competition from Asia, weakening demand in Europe and China, and high energy and labour costs are cited as key reasons behind the pressures facing the European **automotive** sector. These challenges led Volkswagen to announce that they will cut 35 000 jobs by 2030 as part of a restructuring plan. However, these issues are not unique to Volkswagen but affect the entire automotive industry in Europe. Audi announced that they are shutting down their production facility in Brussels on 28 February 2025, with approximately 3 000 staff affected. Ford also reported that it plans to cut 4 000 jobs in Europe by the end of 2027. Stellantis announced that they will shut down their van producing factory in the UK in April 2025.

The slowdown in EU automotive industry, and especially electric vehicles, is having a knock-on effect throughout the supply chain, including battery production, with Northvolt filing for Chapter 11 bankruptcy protection in the United States. This is also affecting machine and car parts makers such as Schaeffler who announced 4 700 job cuts. The metal recycling group Umicore are reducing their workforce by 14% at their German site as lower car demand negatively affects their automotive catalysts business. Tyre maker Michelin announced plans to shut down two factories in France affecting 1 250 workers, underscoring that the entire European automotive supply chain is under pressure.

High electricity prices continue to undermine competitiveness of European energy-intensive industries

After easing in 2023, preliminary data for 2024 shows that average electricity prices for energy-intensive industries in the EU decreased only by 5% compared to the previous year and are still 65% higher than in 2019. Despite declining from the record highs in 2022 and slightly lower compared to 2023, electricity prices for energy-intensive industries in the European Union in 2024 were, on average, still double those in the United States and 50% higher than in China.

Estimated final electricity price for large industrial customers in energy-intensive industries, 2019-2024



IEA. CC BY 4.0.

Notes: Values for 2024 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 included for countries that participate in EU-ETS. For the calculation of the maximum possible state aid for electricity price compensation in European countries, 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 for industry in Texas. The final electricity price for China is based off the final electricity for industry in Inner Mongolia. The final electricity price for India is based off the final electricity for industry in Andhra Pradesh, on a fiscal year basis. The prices for the United States and China are indicative of the average reported prices, individual industries depending on their energy consumption levels and where they are located can face different prices.

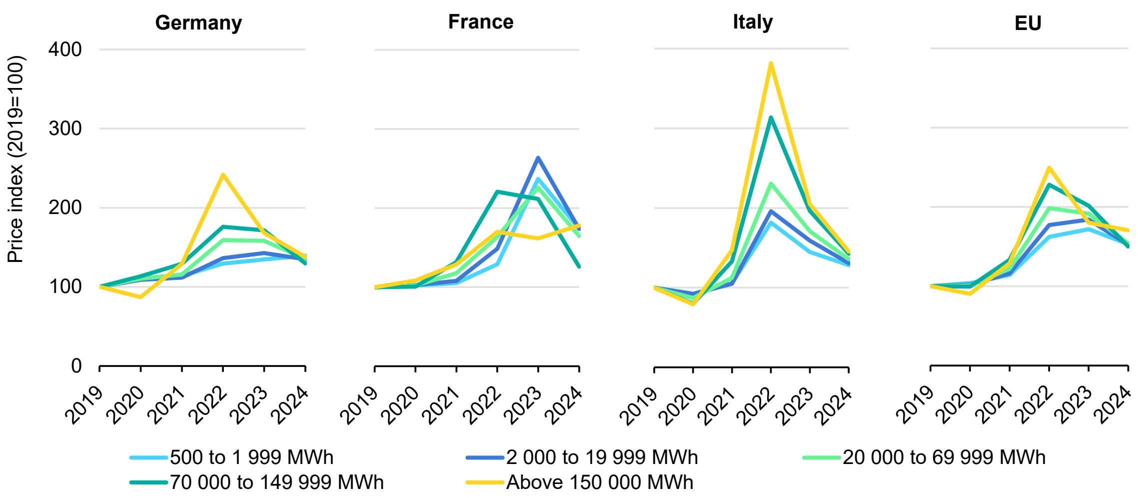
Source: IEA analysis based on data from Eurostat (2024); Official Journal of the European Union (2021); Southeastern U.S. Industrial Rate Survey, Brubaker & Associates (2024); Shanghai Metals Market (2023); Fastmarkets (2024); EUA Futures, Intercontinental Exchange (2023) Central Electricity Authority (2024).

Considering that high energy prices have become a structural issue for some European industries, the European Commission and many countries in the region proceeded to review public aid, mainly through the EU Emissions Trading System (EU-ETS) compensation mechanism. In July 2024, given the difficulties suffered by the **German** energy-intensive industry, the European Commission approved amendments to the ETS compensation mechanism for the country, namely the removal of the maximum aid intensity factor of 75%. Therefore, German companies are expected to receive 100% of the compensation for indirect emission costs incurred between 2023 and 2030, amounting to additional subsidy of EUR 10-15/MWh. In **Spain**, energy-intensive companies are expected to receive 45% of the maximum aid in 2024. In **Italy**, the initial mechanism was budgeted at a constant amount of EUR 140 million/yr, which led to a compensation of 25% of the maximum aid in 2024, but this is expected to increase above 50% in 2025.

Higher electricity prices hit European industries unevenly across consumption levels

In most EU countries, businesses with low to medium electricity consumption enjoyed more stable tariffs between 2021 and 2024, resulting in reduced price volatility compared to larger consumers. On average, EU electricity prices for energy-intensive industries were 160% higher in 2022 than in 2019, while medium consumers experienced an 80% increase and prices for businesses with low consumption rose by 60%. In 2023, the situation shifted, with low to medium consumers continuing to face significant price increases, particularly in France, where businesses that consume between 2-20 GWh/year saw a 77% rise. Differences became less noticeable across consumption levels in 2024 in most EU countries, with retail prices for industry about 1.5 times higher than in 2019 on average in the European Union.

Electricity price index relative to 2019 for industrial customers in the EU and selected countries by consumption level, 2019-2024



Notes: 2024 prices are estimated based on data for H1 2024. Prices for industrial customers with consumption level above 150 000 MWh are adjusted to include ETS compensation mechanisms.
Source: IEA analysis based on data from Eurostat (2024).

The main reasons for the differences in trends across consumption levels and countries include the exposure of each type of industry to wholesale market trends due to their electricity procurement strategies (e.g. share of spot market vs long-term procurement), state mechanisms designed to cap prices, varying compensation or tax, levies and fees exemptions for certain businesses in 2022-2023, and regulatory measures such as the ARENH mechanism in France.

Electrification of transport and heating sectors continues, though some slowing was observed in 2024

The EV stock in the European Union continued to rise in 2024 but the growth was slightly weaker compared to the previous year. In 2024, while new car registrations remained relatively stable (+0.8% y-o-y), new registrations of BEV sales declined by 5.9% and of PHEV were 6.8% lower. The market share of BEVs in total car registrations fell from 14.6% in 2023 to 13.6% in 2024.

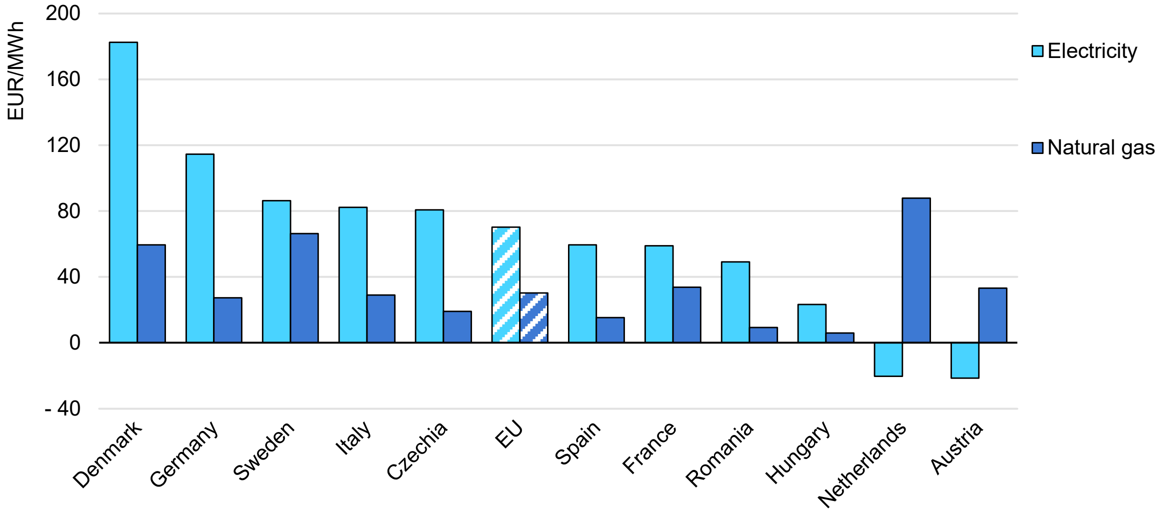
National EV subsidy policies have a strong impact on sales, as witnessed by the recent rollback of subsidies in the two main markets in the European Union. In Germany, following the end of the environmental bonus (which subsidised around 2.1 million EVs since 2016 with a total cost of EUR 10 billion) in December 2023, an 18.2% decrease in EV registrations was reported for the year 2024. Similarly, in France, reforms to the Ecological bonus and malus led to a 5.2% decline in EV registrations during this period. By contrast, countries with supportive regulatory environments posted strong increases in sales. In Belgium, attractive depreciation rates for companies acquiring BEVs and a purchase subsidy of EUR 5 000 per BEV introduced in Flanders led to a 36.9% increase in sales of this type of EV in 2024. The share of BEVs in new registrations in Belgium has increased significantly, reaching 28.5% in 2024, up from 19.6% in 2023.

Even though installed heat pump stock continues to rise, a slowdown in growth has been observed in the European Union since 2023. Heat pump sales decreased across the European Union in 2023 and this trend continued into the first half of 2024. Sales in H1 2024 were 47% lower in 13 European countries compared to the same period the previous year, dropping back to 2019 levels. A contributor to this slower growth was the changing policy and subsidy landscape across various member countries. Even though prices for natural gas in Europe in 2024 are still above the pre-crisis levels, the decline from the 2022 record highs has put downward pressure on switching from a gas boiler to heat pump. This is also related to how electricity tariffs and energy taxes are designed, and to what extent they incentivise a switch from owners of a fossil-fired boiler to a heat pump.

EU households face electrification barriers from various taxation policies related to electricity and natural gas

The taxes, fees, levies and charges component in electricity prices was reduced by EU countries to compensate for sharp increases in the energy and supply component in 2021-2022, falling below EUR 50/MWh for households on average in the second semester of 2022. Moderate but continuous increases in this component of retail prices have been observed in 2023, and in the first half of 2024 it reached EUR 70/MWh. As a result, EU households now pay 130% more taxes, fees, levies and charges for electricity than for gas per MWh.

Taxes, fees, levies and charges component of electricity and natural gas prices for households, January-June 2024



Notes: EU aggregate is calculated by weighting the national prices with the latest available consumption.
Source: IEA analysis based on data from Eurostat.

Part of the gap is explained by the higher overall price of electricity, which was 2.6 times the price of gas in the same period, and by the percentage-based nature of some taxes such as VAT, which was 14.5% for electricity and 12% for gas on average for EU households. However, non-VAT taxes, fees, levies and charges were still EUR 11.4/MWh higher for electricity, and the highest differences were EUR 73.2/MWh in Denmark and EUR 35.6/MWh in Italy. In other EU countries, such as the Netherlands and Austria, this part of the taxes, fees, levies and charges component reached EUR -67/MWh[12].

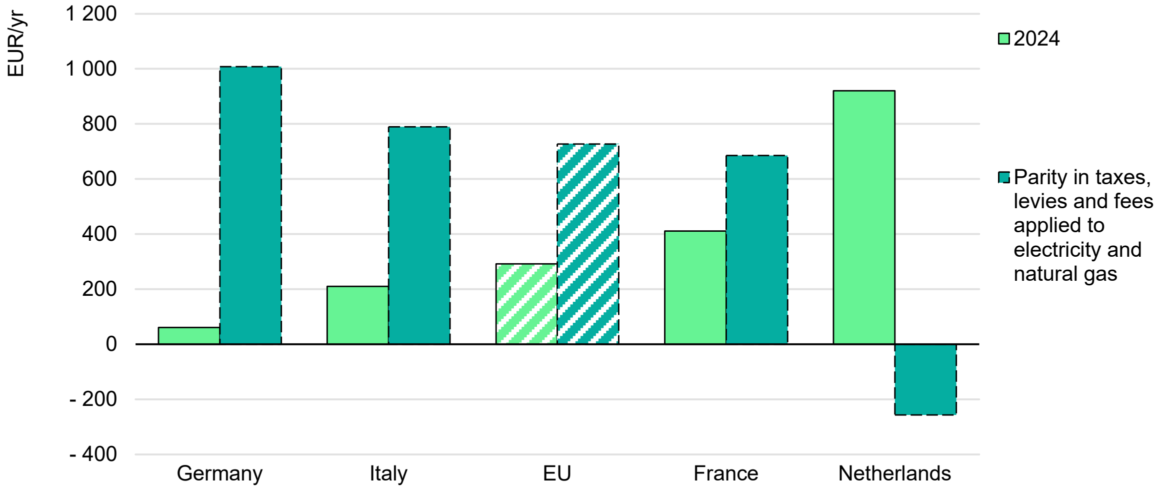
The higher taxation on electricity affects the incentives for electrification in residential settings. Despite ongoing efforts to increase the use of heat pumps and electric cooking, these barriers associated with electricity can slow the transition. With natural gas taxes, fees, levies and charges averaging EUR 30/MWh across the European Union, and a much lower price per MWh than electricity, natural gas can possibly be seen by households as a more budget-friendly choice for home heating and domestic hot water.

Given their high efficiency, heat pumps provide 3-4 times more heat than direct electric heating with the same energy consumption, and up to 4.5 times more compared to gas boilers, and represent a major opportunity for EU countries to accelerate energy efficiency and reduce emissions in the residential sector. Up to

[12] Negative values reflect government interventions such as subsidies, tax reductions and rebates to shield households from surging electricity prices, demonstrating strong support measures.

1.8 t CO_2 emissions could be avoided yearly per individual heat pump installed. In countries with comparable prices of electricity and natural gas, heat pumps can reduce bills by 60-90% depending on the level of insulation, but they can also lead to higher bills for households in countries where electricity prices are 3-4 times higher than gas.

Energy bill savings for the average household switching to a heat pump from a gas boiler, excluding fixed costs and potential subsidies, 2024



Notes: Parity in taxes, fees, levies and charges represents a scenario in which the taxes, fees, levies and charges component of gas and electricity prices for households would be the same in absolute values, and equal to EUR 70.2/MWh (EU27), EUR 114.5/MWh (Germany), EUR 82.3/MWh (Italy), EUR 58.9/MWh (France) or EUR -20.4/MWh (Netherlands). Taxes, fees, levies and charges component of electricity prices values as of H1 2024. EU aggregate is calculated by weighting the national prices with the latest available consumption. The calculation assumes household heating requirements of 6 MWh/year and hot water requirements of 4 MWh/year, air source heat pump with heating SPF = 3.5 and hot water SPF = 2.8, and gas boiler efficiency of 92%.

Source: IEA analysis based on data from Eurostat, Wolf, HeatpumpMonitor.org, Energy Efficiency 2024.

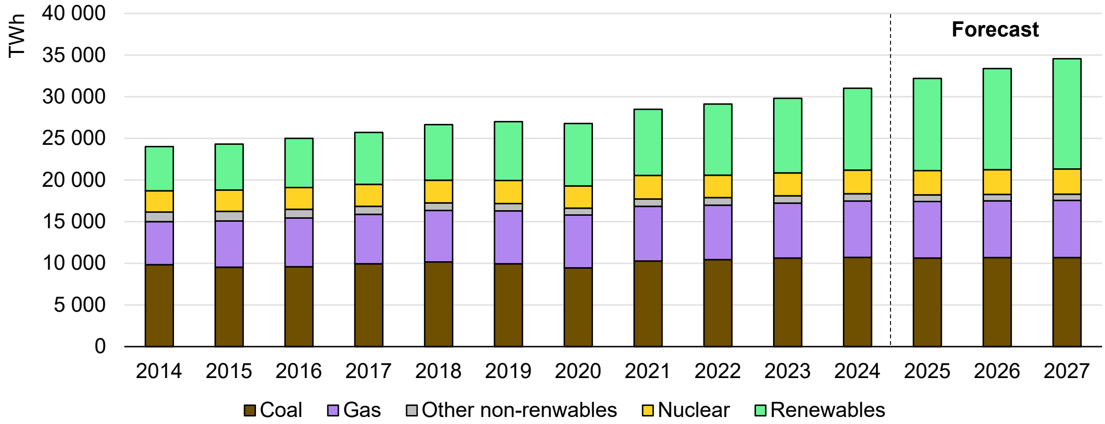
Supply: Renewables dominate as coal's share continues to contract

Clean energy sources pass a wave of milestones in electricity supply in 2025-2027

Clean energy sources in global power generation are on track to break new records over the 2025-2027 forecast period. Low-emission sources – renewables and nuclear – are expected to meet all global demand growth out to 2027. Solar PV is set to become the second largest low-emissions source of electricity generation in the world by 2027, after hydropower. Renewables, collectively, will surpass coal-fired generation in 2025 and coal's share will decline below 33% for the first time in the last 100 years. Nuclear generation will reach a new record high in 2025, driven by a recovery in output in France and Japan, and new reactors entering operation in China, India and Korea, among other countries. Nuclear energy will continue to set a new record every year thereafter. The share of low-emissions sources is forecast to increase from 41% in 2024 to 47% in 2027.

As the share of renewable energy sources in the electricity generation mix rises, understanding periods with reduced wind and solar PV generation due to weather conditions becomes important. While such events can potentially strain the power system, having enough dispatchable capacity and long-duration storage will be essential. These variable renewable energy droughts are explored in-depth below (see *Spotlight: Dunkelflaute events as potential stress tests*).

Global electricity generation by source, 2014-2027



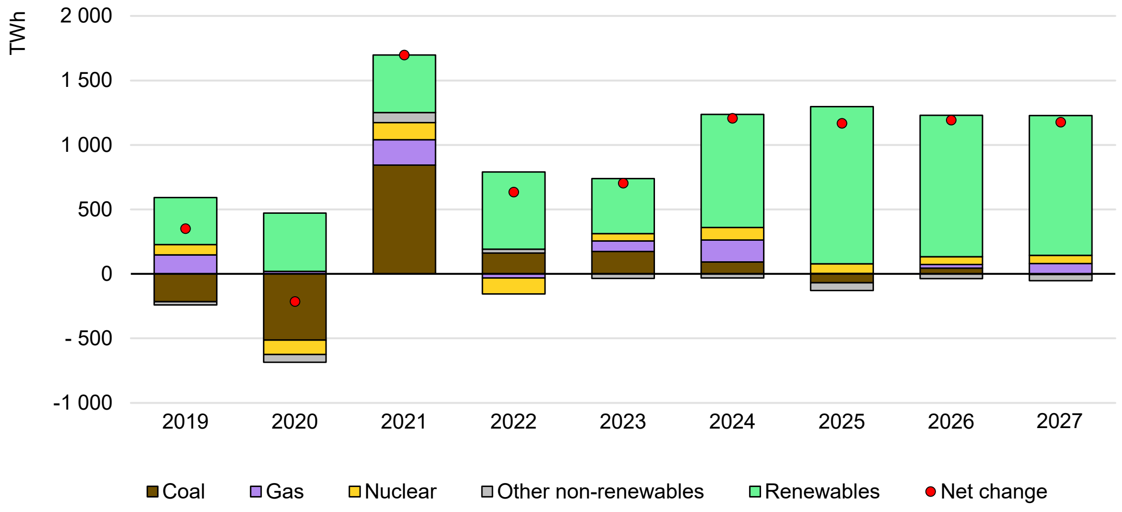
Notes: Other non-renewables includes oil, waste and other non-renewable sources. Data for 2025-2027 are forecast values.

Renewables set to meet around 90% of global electricity demand growth out to 2027

Global electricity generation from renewable energies rose 10% y-o-y in 2024, double the 5% increase in 2023. Hydropower generation, which had declined by around 2% in 2023 amidst severe droughts in many regions, most notably in China, posted a substantial rebound in 2024, up by 4%. The increase was led by a strong recovery in both China and Europe due to higher precipitation.

At the same time, solar PV generation grew by 30% in 2024, its highest growth rate since 2017, totalling a record gain of 475 TWh y-o-y. More than half of the growth in solar PV generation came from China. Over the 2025-2027 forecast period, we expect global solar PV generation to rise by about 1 800 TWh. As a result, solar PV is set to meet around half of the growth in global electricity demand in our outlook period. The strong growth trend in solar PV is accompanied by continued expansion in wind generation, which is forecast to meet around one-third of additional global electricity demand during this period. We forecast total renewable generation to increase each year by 10% on average out to 2027, adding around 3 400 TWh globally in total.

Year-on-year global change in electricity generation by source, 2019-2027



Notes: Other non-renewables includes oil, waste and other non-renewable sources. Data for 2025-2027 are forecast values.

Global nuclear generation rose 3.5% in 2024, after a 2.1% increase in 2023. The maintenance of the French nuclear fleet progressed faster than initially forecast, boosting generation by almost 13%. Global nuclear generation is expected to rise by 2.3% annually on average in 2025-2027, as new reactors in China, Korea and Europe, as well as restarted ones in Japan, become operational.

Following a 1.7% y-o-y increase in 2023, coal-fired generation rose by a smaller 1% in 2024, but nonetheless reached a new record. Despite elevated electricity demand due to heatwaves in many regions, such as China and India, strong growth in the output of clean energy sources tempered gains. We expect coal-fired generation to remain relatively flat over the forecast period to 2027. The declines in Europe and the United States, as well as in Australia, Japan and Korea, will be offset by significant increases in other Asian countries. While growth in coal-fired generation in China will be constrained by the massive expansion of low-emissions energy sources, coal-fired output is expected to rise significantly in India and Southeast Asia over the forecast period.

While growth in coal-fired generation slowed in 2024, natural gas-fired generation grew slightly faster than in 2023. Following an increase of 1.3% y-o-y in 2023, global gas-fired generation rose 2.6% in 2024, reaching a new global high. Europe was the only major region where gas-fired output declined. Comparably elevated gas prices in 2024 amid a colder winter in Europe and global geopolitical tensions are expected to support more gas-to-coal switching in parts of the world in the short term, resulting in a relatively flat trajectory in our global gas-fired generation forecast for 2025. Nevertheless, we expect global gas-fired output to rise by an average annual rate of around 1% in 2026-2027. Declines in advanced economies will be more than offset by increases in other regions. The Middle East is set to see a surge in gas-fired generation in 2025-2027 as the continued switch from oil to natural gas gains pace in line with policy targets in many countries in the region, especially Saudi Arabia, which sees gas generation jump 10%, while oil burn in power plants falls more than 15%. Gas-fired generation in China, India and Southeast Asia also increases, while at the same time natural gas-fired generators' role in providing flexibility to the power systems increases.

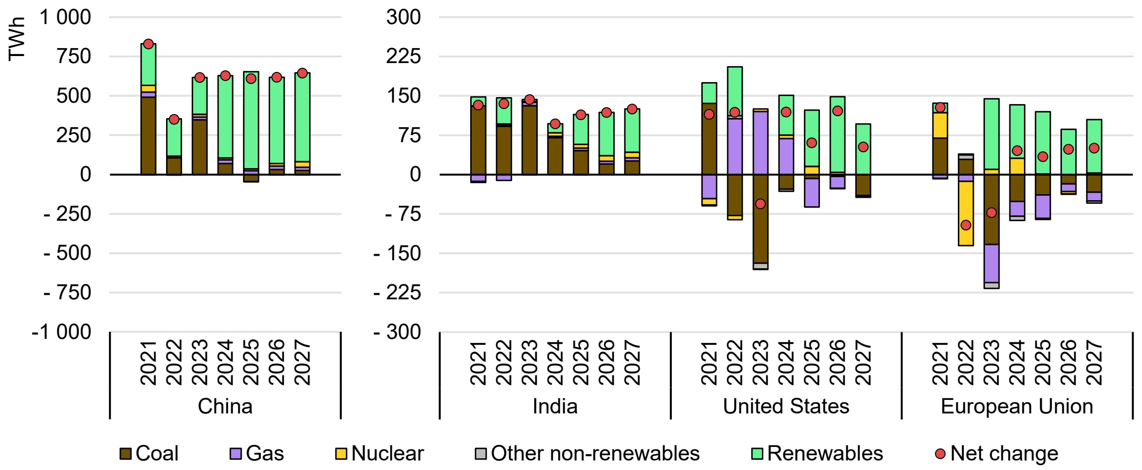
Rapid expansion of solar PV is the common trend across China, India, the US and the EU

Solar PV is booming worldwide, breaking records in both emerging and advanced economies as its cost rapidly declines. Electricity generation from solar PV surpassed that from coal in the European Union in 2024, with its share in the generation mix exceeding 10%. Other major economies, such as China, the United States and India, are all set to see solar PV's share reach 10% over the 2025-2027 forecast period as well.

In 2024, China solar PV generation jumped by a sharp 46%, much higher than the average annual rate of 27% observed over the previous five-year period (2019-2023). Wind generation also rose significantly in 2024, up by 12%. Hydropower increased by 11%, rebounding from its previous low in 2023, when it fell by 5%. Together with expanding solar PV and wind power, this also limited coal-fired generation in China, which rose by a modest 1.2%, after a substantial rise of more than 6% in 2023. Rebounding hydropower and rapid growth in renewable energies met over 80% of China's 7% growth in electricity demand in 2024.

From 2025-2027, coal-fired output in China is expected to remain relatively flat as low-emission energy sources – renewables and nuclear – continue to expand. As a result, the share of coal-fired generation in China's electricity mix is projected to decline to less than 50% in 2027, down from almost 60% in 2024. Although the downward pressure on Chinese coal-fired power generation is largely structural, weather conditions and economic shocks can cause upticks in individual years. At the same time, the rising share of VREs are accompanied by system integration challenges, increasingly requiring sources of flexibility in the grid, shifting the role of coal-fired power plants towards ensuring system adequacy. Gas-fired power generation, characterised by its fast-ramping speeds, is projected to grow at an average annual rate of 7%, playing a critical role in balancing the grid and complementing the variability of renewable energy sources.

Year-on-year change in electricity generation by source in selected regions, 2021-2027



Notes: Other non-renewables includes oil, waste and other non-renewable sources. Data for 2025-2027 are forecast values.

In India, hydropower generation increased by 2.5% in 2024 versus 2023, but was around 15% lower than in 2022 due to the impacts of El Niño. Solar PV generation grew by 15% y-o-y. Amid record-breaking heatwaves that contributed to strong electricity demand growth, the government directed coal-fired power plants to operate at full capacity, a measure extended until the end of February 2025. Coal-fired generation increased by 5% y-o-y, maintaining its role as the backbone of India's power system, with a 74% share of the electricity mix in 2024. Gas-fired output rose 6% y-o-y, supported by emergency mandates requiring underutilised gas plants to ramp up operations to address rising demand.

From 2025 and 2027, coal-fired generation in India is forecast to grow more slowly, rising by 2% annually, despite an expected average growth rate of 6.3% in electricity demand. This is because renewable energy sources are also forecast to grow significantly, increasing their share from 21% in 2024 to 27% in 2027. Solar PV generation is expected to expand at an average annual rate of over 28% from 2025 to 2027, roughly doubling its output. Wind generation is projected to grow by an average 11% annually. Nuclear power also showed strong growth in 2024, up by 13% y-o-y as the Kakrapar 4 reactor started commercial operation in March 2024, following the start of commercial operation of Kakrapar 3 in 2023.

In the United States, gas-fired power generation grew by 3.7% y-o-y in 2024, maintaining its position as the largest source of electricity with a more than 40% share in the generation mix. Wind power output increased by 6.4% y-o-y in 2024, accounting for 10% of total electricity generation and reinforcing its role as the largest source of renewable energy. Notably, in March and April 2024, wind generation surpassed coal for two consecutive months for the first time in US history. In 2024, solar PV achieved significant growth, increasing by almost 30% y-o-y and becoming the second-largest renewable electricity source, surpassing hydropower. This growth was largely driven by utility-scale capacity additions, especially in Texas and California. Hydropower generation declined by about 1% y-o-y in 2024 and was approximately 7% lower than in 2022, reflecting the ongoing impacts of droughts, particularly in the Pacific Northwest. Coal-fired power generation decreased by 3.7% y-o-y in 2024, continuing its downward trajectory. Nuclear power generation rose slightly in 2024, rising by 1% y-o-y as the Plant Vogtle Unit 4 commenced commercial operations.

Over the forecast period, US coal-fired generation is expected to decline on average by around 2%. Gas-fired generation is expected to decline only slightly, by around 1%, in 2025-2027 amid robust demand growth. US electricity generation from renewables is expected to grow on average by 10% annually. Nevertheless, the significant uncertainty in the demand trends for data centres means that, in the case of higher electricity demand growth, upward potential for gas-fired output exists.

In 2024, renewable electricity generation in the European Union grew by 8.4%, with its share of the total mix reaching almost 48%, and is set to surpass 50% in 2025. Hydropower generation increased by 10% y-o-y in 2024, to a record high of 362 TWh. The highest hydropower output in the European Union before this was 370 TWh in 2014. Solar PV generation rose 22%, as new capacity installations gained pace. By contrast, wind power generation rose by a modest 1%, down from the 13% growth observed in 2023. Nuclear power generation was up by 5% in 2024, supported by the higher output of the French fleet. Amid rising production from clean energy sources, fossil fuel-fired generation continued to decline in 2024, with coal-fired output falling by 15% and gas-fired by 6%.

From 2025 to 2027, renewable generation in the European Union is forecast to increase on average by 7% annually, with its share of total output reaching 56%. Offset by the strong growth in renewables, coal-fired generation is forecast to decline on average by 11% annually over our outlook period and gas-fired power will contract by 6% on average.

Spotlight: *Dunkelflaute* events as potential stress tests

Temporary periods with reduced wind and solar PV generation may put additional strain on the power system, especially if they occur during periods of high electricity demand, such as during colder winter seasons with increased heating demand, or hotter summers with higher cooling load. During these periods, power demand is met predominantly by dispatchable power plants and using various flexibility measures. These events can also lead to temporary and briefly higher prices on the wholesale markets if supply is tight. Having sufficient (low-emissions) dispatchable capacity and long-duration storage, among other flexibility options such as demand-side flexibility and interconnections, is important to effectively manage such periods.

In November and December 2024, there were several occasions in Northern Europe when combined wind and solar PV electricity generation was very low, the so-called compounded VRE droughts or *Dunkelflaute* events, which led to tighter supply and several hours of extremely high electricity prices on the wholesale markets. In 5-7 November and 11-12 December Germany and the surrounding regions were affected. In early 2025, on 8 January, the United Kingdom had a relatively localised *Dunkelflaute* that lasted for about a day. Low wind availability during the nighttime combined with interconnector unavailabilities, power plant maintenance outages and elevated electricity demand led the national energy system operator (NESO) to issue a notice due to low system margins.

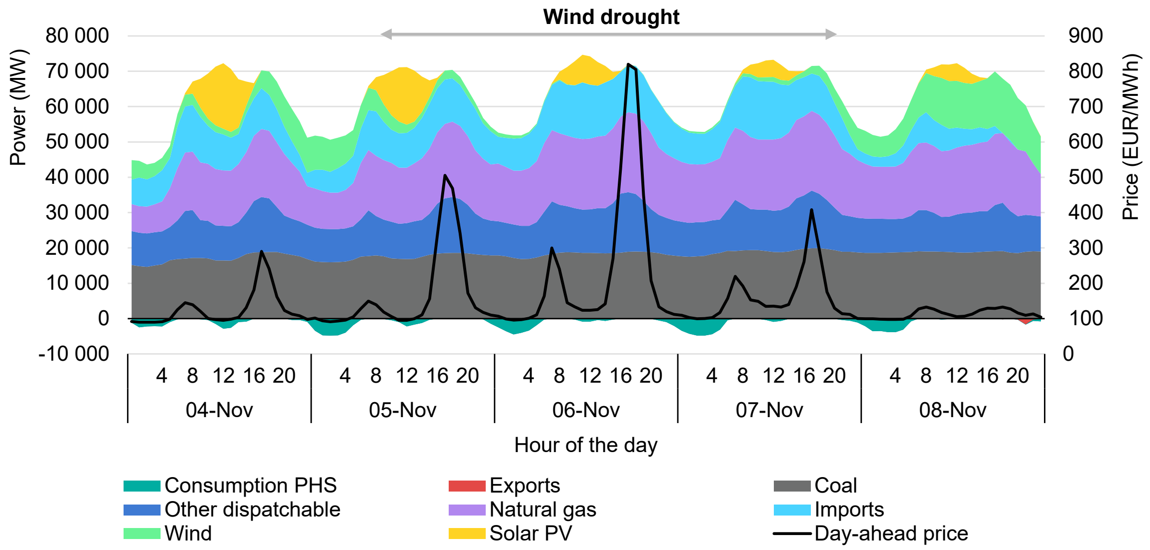
All these events were managed successfully without any impact on the supply of electricity, showing the resilience of the power systems and the underlying market mechanisms. The price spikes observed during the period of a few hours only had a very limited impact on average prices but acted as important signals to incentivise flexible generators to produce more and for flexible consumers to reduce their consumption, while also facilitating the efficient import and export of electricity. Nevertheless, a comprehensive understanding of such events is important to plan accordingly as both electricity supply and demand become more weather-dependent.

A case study: *Dunkelflaute* events in Northern Europe on 5-7 November and 11-12 December 2024

The recent *Dunkelflaute* occurrences in Northern Europe on 5-7 November and 11-12 December 2024 provide relevant case studies for understanding how well-interconnected markets with sufficient dispatchable capacity allow for a resilient system under the corresponding market price signals, even when such events affect a wider region.

Day-ahead electricity prices in Germany and parts of the Nordic countries exceeded EUR 900/MWh in a single hour on 12 December after sunset, although prices were already high during daytime, averaging around EUR 500/MWh between 07:00-15:00. Solar PV generation is typically lower during the winter season in Northern Europe, and this day was not particularly different. The solar PV capacity factor for the whole day was an estimated 0.7%, compared to the December average of 1% for the 2019-2023 period. By contrast, output from wind was substantially below its seasonal average and a temporary wind drought was observed. The average capacity factor of wind generation was 2% on this day, compared to the December average of 26% over the period 2019-2023. The day before, 11 December, had also recorded very low wind output at an average capacity factor of 3%, with prices exceeding EUR 400/MWh around 16:00-17:00.

Electricity supply profile in Germany, 4-8 November 2024



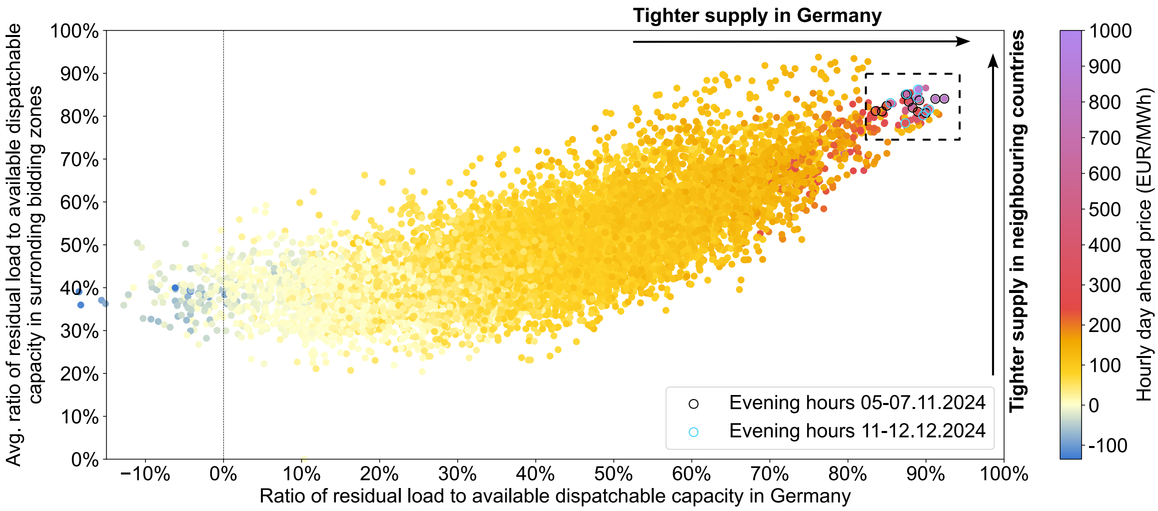
Notes: Realised generation is plotted. PHS = pumped hydro storage. Other dispatchable energy includes power generation from coal, lignite, oil, other non-renewable fuels, hydro reservoirs, hydro run-of-river, pumped hydro (turbining), bioenergy, and geothermal.

Source: IEA analysis based on data from Fraunhofer ISE (2024).

A precursor to 12 December was on 5-7 November, when wind power generation in Germany and neighbouring countries was also very limited. The average capacity factor of wind generation in Germany was 6% on 5 November, fell to as low as 0.5% on 6 November, and then increased again slightly to 2.5% on 7 November. By contrast, the average capacity factor for wind for the month of November was 24% over the period 2019-2023. Germany's day-ahead prices surged after sunset, ranging between EUR 400/MWh and EUR 800/MWh during the hours of 17:00-18:00 over these three days. The neighbouring bidding zones in Denmark and the Netherlands also saw price spikes in the EUR 400-500/MWh range during the same hours.

When weather conditions such as wind droughts occur, they may impact multiple countries simultaneously. In both these events, the *Dunkelflaute* was not localised but occurred over a wider area. Similarly, the price surges[13] that were observed happened when they would be most likely to occur. Our analysis based on publicly available data shows that the evening hours between 16:00-20:00 pm, when the price spikes occurred, were also among the hours in 2024 with particularly tight supply. Some of the highest residual load to available dispatchable capacity ratios were observed during these hours in 2024 – both in Germany and, on average, in neighbouring countries. In the countries Germany is interconnected with, wind power generation was on average 60% lower during 5-7 November compared to the same period the previous year and about 30% lower during 11-12 December. Hence, supply was particularly tight during these evening hours across the region due to similar weather conditions.

Hourly day-ahead electricity prices in relation to the ratio of residual load to available dispatchable capacity, Germany and surrounding bidding zones, 1 January 2024-31 December 2024



Notes: Residual load = load – (wind + solar PV generation). Available dispatchable capacity = total installed dispatchable capacity - sum of outages of dispatchable generation units. A negative ratio of residual load to dispatch capacity means that the residual load is negative, i.e. there is more wind and solar PV generation than the load, which would be exported to neighbouring countries. Average of surrounding bidding zones is a weighted average based on the transfer capacity to Germany. These correspond to the bidding zones AT (Austria), BE (Belgium), CH (Switzerland), CZ (Czech Republic), DK1 (Western Denmark), DK2 (Eastern Denmark), FR (France), NL (Netherlands), NO2 (Southern Norway) and PL (Poland). The bidding zone SE4 (Southern Sweden) is omitted due to data inconsistencies in the source.

Source: IEA analysis based on data from Fraunhofer ISE (2025), ENTSO-E (2025) and BNetzA (2024).

[13] This refers to the fact that the prices were some of the highest prices in 2024, but not to their exact levels.

Thanks to being well-interconnected and the market design allowing for short-term price signals that incentivises flexible operation, imports and exports of electricity helped countries meet the electricity demand cost-effectively. For example, Germany imported a significant amount of electricity during this *Dunkelflaute* period, though the import levels were below the maximum, reflecting the wider geographical impact of the wind drought. During the evening hours, Germany's net imports of electricity averaged 10-13 GW over 5-7 November and 13-15 GW on 11-12 December. These are below the highest net imports observed in 2024 of 17 GW in the morning of 12 December at 8:00, but much higher than the 1-2 GW averages for the full months of November and December 2024.

When VRE droughts occur simultaneously with elevated electricity demand and/or during outages of thermal power plants as well as interconnectors, they can potentially put significant strain on the system, however, this was not the case during 5-7 November and 11-12 December. In these two events, electricity consumption increased amid colder weather more than in previous weeks, but it was not exceptionally high, and similar load levels were realised in other periods in 2023-2024.

Unavailability of plants, considering both scheduled and unscheduled outages, was also at relatively similar levels compared to 2023, according to data from ENTSO-E transparency. It should be noted though that compared to the same period in November-December 2023, 7 GW[14] of dispatchable capacity was retired in 2024, almost 85% of this composed of coal and lignite-fired plants, and the rest mostly oil-fired. During the same period, 0.9 GW additional dispatchable capacity was commissioned, 0.4 GW of which was based on natural gas and 0.3 GW oil (classified as a grid stabilisation plant), with the rest consisting of assets based on biomass, waste and process heat.

The ENTSO-E winter outlook does not foresee any adequacy risks for the 2024/2025 winter period in Germany, and there are about 10 GW of market reserves, mostly consisting of coal-fired power plants, which are activated outside the power market as a redispatch measure or in response to prolonged periods of supply shortages (rather than individual temporary price surges in the wholesale market).

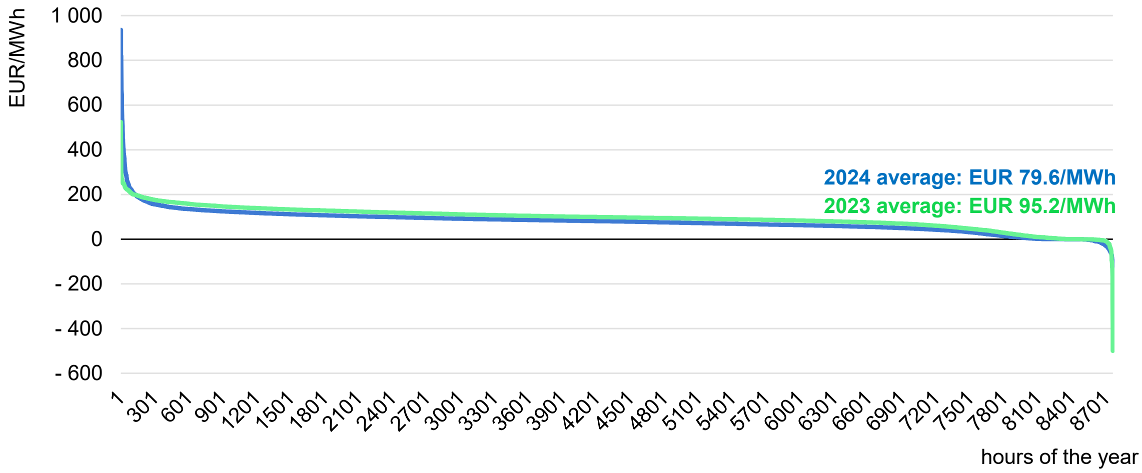
The price surges seen during the two *Dunkelflaute* events discussed above had limited impact on the average price. During the total 120 hours of these five days considered, there were only four hours with prices above EUR 800/MWh and 34 hours with prices above EUR 300/MWh[15]. Assuming all the prices above

[14] The capacities given here refer to net generation capacity.

[15] There were 41 hours in 2024 where hourly day-ahead electricity prices in Germany were higher than EUR 300/MWh, excluding the price surge seen on 25 June 2024, stemming from a technical issue on the trading platforms.

EUR 300/MWh during this period would not exceed this value, the impact of these 34 hours on the annual average price of EUR 79.6/MWh in 2024 was limited to an increase of 1%. The impact of these spikes on the average monthly price was around a 3% increase in November and 7% in December.

Day-ahead hourly electricity price duration curves in Germany, 2024 vs. 2023



Notes: Price spikes stemming from a technical issue on the trading platforms on 25 June 2024 are not plotted in this chart, but the average price shown includes these. For six hours on that day prices were above EUR 980/MWh and for one hour exceeded EUR 2 300/MWh.
Source: IEA analysis based on data from SMARD (2025).

There are multiple factors that determined the exact level of the price spikes. Prices in excess of EUR 800/MWh on individual hours are well above the fundamental prices that would be expected from the marginal cost of the most expensive oil-fired generation assets (e.g. around EUR 300/MWh) based on the prices of energy commodities at the time. Thus, the price levels seen are likely to include higher markups, characterised by scarcity pricing. Excluding 6 November 17:00-18:00, which was the tightest supply situation according to our analysis, there were comparable scarcity situations in 2023 and 2024 but prices did not rise as high as these levels. Prices in a scarcity situation are determined by the value of the lost load for consumers. In this case, it is possible that for energy-intensive producers that have a certain degree of load flexibility, the costs associated with stopping production because of a few high-priced hours might have exceeded the cost of the electricity, which would be reflected in their willingness to pay, influencing price formation on the spot market.

There could be multiple potential causes reflected in these elevated markups and prices, such as reduced dispatchable capacity availability due to retirements, effects of planned maintenance or unplanned outages, and peak-load generators that are expecting lower utilisation rates overall and wanting to recover a higher portion of their fixed costs when the opportunity presents itself. Due to concerns voiced by various stakeholders regarding the nature of price formation in these hours, the German competition authority, Bundeskartellamt, indicated they will investigate the situation. At the time of writing of our report, these investigations were not yet concluded.

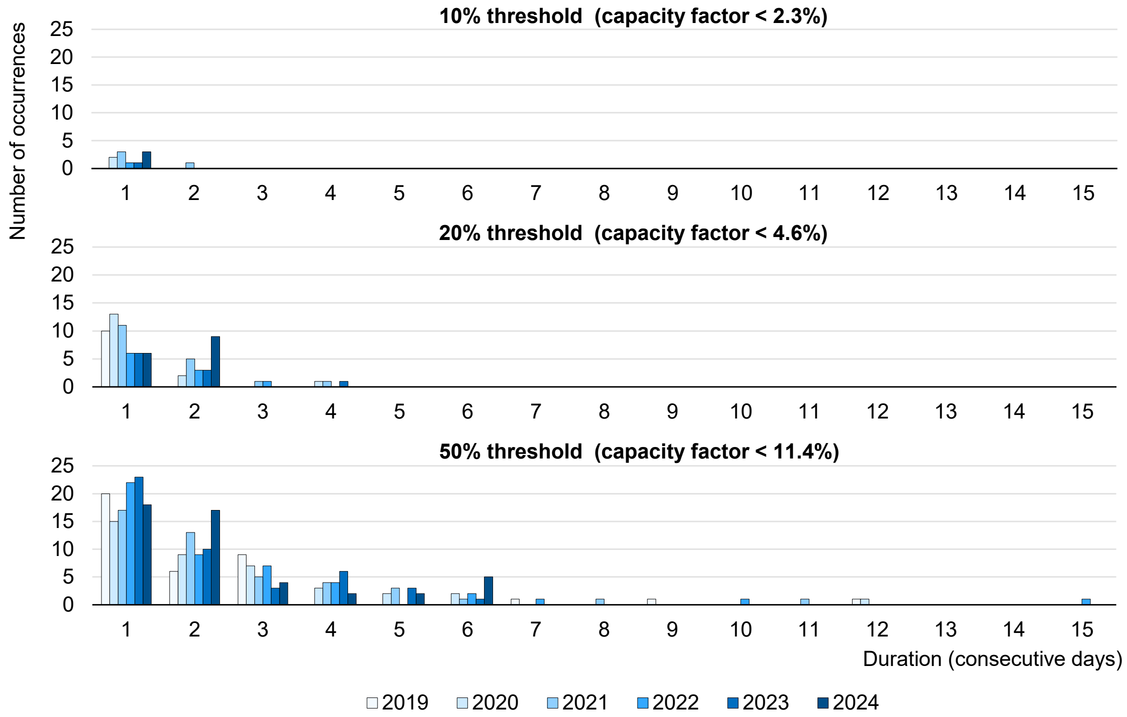
Definitions of VRE droughts vary widely; standardised methods can allow for better comparison across regions

There are various terminologies for periods with substantially reduced output from weather-dependent technologies such as hydropower, wind and solar PV. One common approach in the prevailing literature is to refer to such events as energy droughts. Hydropower droughts can be considered a subset of energy droughts, although they are generally associated with longer time periods, which can range from months to multiple years. By contrast, wind and solar droughts can occur for shorter durations, lasting hours or days, and are therefore usually treated as a separate category. In the case of solar and wind supply shortages, they can also be referred to as variable renewable energy droughts. VRE droughts may occur for generation sources individually or in a compounded manner, such as when both solar and wind droughts are present at the same time. This is the case commonly referred to as *Dunkelflaute*, which means dark doldrums in German.

Whether an event can be classified as such depends on the metrics that are applied. A common method is to define a VRE drought based on thresholds for capacity factors, which can be set for total VRE generation as a whole or individually for different VRE technologies. A VRE drought is defined then if the realised capacity factor is below the threshold. These thresholds can be set as the minimum capacity factors of these technologies individually or, for example, in relation to their mean capacity factors (e.g. 20-50% of the mean capacity factor). This metric can be further combined with a predefined minimum duration (e.g. 24 consecutive hours) to identify relevant events. In 2024, for example in Germany, there were only three events where the daily average capacity factor of wind generation (including onshore and offshore) was below 10% of the annual average capacity factor of the 2019-2024. This means that during these three events, the daily average capacity factors was less than 2.3%, compared to the 2019-2024 mean of 23%. All three events lasted no longer than one day. If we instead apply a threshold of 50% of the average annual capacity factor over the last five years, then in 2024 there were five events lasting six consecutive days in which the average daily capacity factor was below 11.4%.

Other methodologies in defining and identifying VRE droughts include quantile-based thresholds derived from the underlying generation source. One recent methodology developed involves defining standardised indices that can facilitate comparisons among regions with different climates and installed capacities. Similar to well established indices for meteorological droughts, a standardised renewable energy production index (SREPI) based on cumulative distribution functions can be defined. To explore the system impacts of energy droughts and include the load in the analyses as well, this can be accompanied by defining a standardised residual load index (SRLI). Other studies that also focus on the combined VRE drought and high demand occurrences use the definition positive residual load events, when VRE generation falls short of meeting electricity demand and additional flexibility in the system is needed. A comprehensive overview of recent literature and a discussion of energy drought events and long-duration energy storage needs can be found in a recent study by the IEA Hydro Technology Collaboration Programme.

Different ways to classify wind droughts and their number and duration depending on the thresholds applied to the mean capacity factors, Germany, 2019-2024



Notes: CF = capacity factor. The analysis includes total wind power generation (onshore and offshore) and is based on daily average capacity factors. The average capacity factor for total wind power over 2019-2024 was 23%. Applying a threshold of 10% means that days are considered where the wind generation had an average daily capacity factor of less than 2.3%. In 2024, for example, there were only three events that met this condition, and all of them lasted no longer than one day.

How often VRE droughts occur and how long they tend to last differ across regions based on meteorological characteristics. At the same time, these metrics are directly influenced by how a VRE drought is defined, such as by the thresholds or indices that are applied and whether the residual load is also included in the definition or not. For example, ENTSO-E in their 2024 report that investigates system flexibility needs up to 2030 states that prolonged VRE shortage periods might occur 2-4 times per year in Europe, lasting on average up to 6-10 days.

They define “a VRE shortage period” if one or more of the following conditions persist over four or more consecutive days in their dataset: (1) total VRE generation falls within the lowest 10% of values; (2) the ratio of VRE generation to system demand falls within the lowest 10% of values; (3) the ratio of residual load to system demand exceeds the highest 10% of values.

VRE droughts are not new and were managed successfully in different regions in many instances

While the *Dunkelflaute* events in Europe that took place in November and December 2024 have attracted significant attention, is not a new phenomenon. Instances of VRE droughts that resulted in a tight supply situation were observed in Europe over the last decade, which were dealt with successfully without any impact on security of supply. For instance, in April 2018, the Netherlands experienced minimal sun and wind generation combined with increased demand, prompting the main transmission system operator, TenneT, to issue an emergency call for additional measures. Similarly, Belgium faced nine consecutive days of *Dunkelflaute* in January 2017, which was managed via increasing generation from dispatchable resources and higher imports.

VRE droughts are also observed in other regions and are not specific to Europe. In **Australia**, the winter period from May to August has a higher likelihood of VRE droughts with a potentially increased impact as it coincides with higher heating demand in southern Australian states during this period. Most recently, in April and May 2024, very low wind generation was observed across Australia’s southern states; namely, Victoria, South Australia and New South Wales. Over a seven-day period from 11 April to 17 April, the wind power capacity factor in the National Electricity Market (NEM) averaged about 9% according to our estimates. Similarly, over a six-day period ranging from 22 May to 27 May, the mean capacity factor for wind was about 7% and was below 5% on one of those days. For reference, the mean annual capacity factor over the previous three years of 2021-2023 was around 27%. The average for April during this period was estimated to be 22% and for May around 26%. During these recent wind drought events in 2024, wind output in Queensland and solar PV output in NEM overall remained relatively robust, so the total impact of the wind drought was limited.

For the **United States**, a study conducted by the National Renewable Energy Laboratory (NREL) in 2021 covers a three-week period of wind drought that occurred in October 2010 across most of the country. During this period, residual load reportedly remained low, typical for the shoulder seasons. Nevertheless, scheduled maintenance in thermal generation generally takes place during these shoulder seasons due to lower demand and their timing may be impacted by such VRE droughts. While the study notes that such events historically would not be a concern for system planners and operators, it emphasises that as the VRE share increases, this will need to become a focus of planners for ensuring system adequacy.

During the polar vortex weather event on 11-18 January 2024 in the United States, three wind drought events lasting 4-20 hours were observed in the Pacific Northwest region, where wind generation dropped below the 20% of annual production. These events were managed successfully, with hydropower playing a key role in providing flexible supply.

Bracken et al. (2024) provides a standardised benchmark of historical compound wind and solar energy droughts in the United States based on the previously mentioned SREPI and SRLI metrics, concluding that the energy drought characteristics vary across US regions but can last up to six days. The study found that the longest hourly energy droughts occur in Texas and longest daily droughts occur in California. The 2024 Long-Term Reliability Assessment by the North American Electric Reliability Corporation (NERC) also mentions energy droughts and refers to this same study, emphasising the importance of considering such events in planning system resources and storage needs.

In **Japan**, the share of solar PV in electricity generation is 10% and wind only 1%, hence the *Dunkelflaute* events are not expected to have a significant impact currently on the country as a whole. Nevertheless, this weather phenomenon can also be observed there. In Japan, due to typical meteorological patterns such as the rainy season and recurring high-pressure systems, periods of high residual load can occur during summer months. A 2022 study identified four dominant weather patterns which were likely to induce compound solar and wind energy droughts during the summer in eastern Japan. The main cause is identified as rain fronts approaching from the south and cold air coming in from the north. The study uses an exogenously set threshold and defines the VRE drought as a period when daily VRE power generation is less than 10% of the capacity factor over a time frame of one to five days.

The importance of having sufficient dispatchable capacity and long duration storage

As the share of renewable energy sources in the electricity generation mix rises in many regions and they enter higher phases of VRE integration, understanding VRE droughts better and preparing for them accordingly becomes more important. If the VRE drought lasts only 1-2 days, short-term storage capacities and demand-response can help with smoothing the residual load. However, if the situation persists for longer durations, it becomes increasingly difficult to recharge storage capacities and utilise short-term flexibility options. Enhanced grid interconnection across different geographies can help balance the overall energy supply to an extent, given the locational price signals are reflective of the system costs during such events. However, as meteorological conditions can affect the wind and solar output for multiple neighbouring power systems, expanding interconnection capacity may not be enough on its own. Consequently, having sufficient dispatchable capacities and long-duration storage becomes important to effectively manage longer-lasting VRE droughts. In the short-term, pumped hydro storage is a proven and mature technology for longer duration storage that can provide flexibility over a timescale of days to weeks, with thermal energy storage and hydrogen storage being relevant low-carbon technologies in the longer term where the timescale of flexibility can be extended to months (seasonal flexibility).

As highlighted in the IEA report Managing the Seasonal Variability of Electricity Demand and Supply, hydro and dispatchable thermal power plants will remain important providers of secure capacity, alongside other sources of system flexibility discussed above. In a low-emissions power system, these thermal capacities also need to be correspondingly based on low-emissions fuels or include carbon capture and storage. Ensuring sufficient dispatchable capacity in the long-term may require mechanisms and market designs that properly value these generators' critical services, even if they operate infrequently over the course of a year. When conducting resource adequacy assessments, it is crucial to consider the unpredictable nature of weather impacts, which can influence the planning of investments, potential generator retirements, and policy decisions. We devote a separate section in our report to discussing resource adequacy in light of the potentially increasing impacts of weather on power systems (see *Reliability: Extreme weather events make improved security imperative*).

Emissions: Clean energy mitigates CO_2 power emissions in 2025-2027

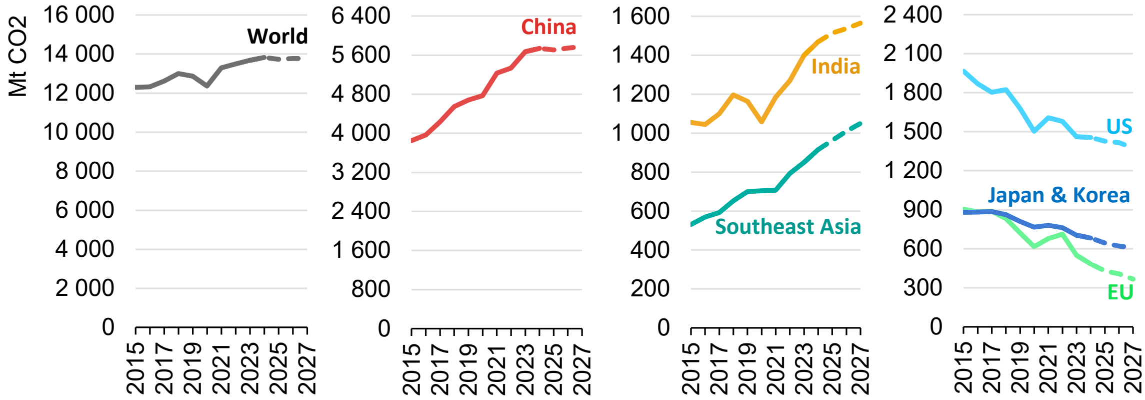
Increased emissions in India and China offset declines in Europe and the United States

Global CO_2 emissions from power generation rose by a modest 1% in 2024, following a 1.4% rise in 2023, due to a 1.3% y-o-y increase in fossil fuel-based generation amid global electricity demand growth of 4.3%. In our 2025-2027 outlook period, global CO_2 emissions from the power sector are expected to stay relatively flat (-0.1%), due to substantial growth in clean energy sources, even as demand is forecast to grow by an annual average of 3.9%. It should be noted that economic shocks, volatile commodity prices and deviations from normal weather conditions such as heatwaves, extreme cold spells or low water availability for hydropower generation can cause the subsequent rate of emissions to vary in individual years. Nevertheless, the trend of clean energy sources limiting fossil-fuelled generation is anticipated to remain robust.

In 2024, reduced power sector emissions in the United States and the European Union were offset by increases in China and, notably, India. The European Union recorded a 12% reduction in emissions from electricity generation, while the United States achieved a more modest 0.3% decline. By contrast, China's emissions rose by 1.3%, driven by 2% growth in fossil fuel-based electricity generation amid strong demand growth of 7%. India saw a 5% y-o-y rise in emissions, underpinned by a similar increase of around 5% in fossil-fired generation to meet robust growth in electricity demand of 5.8%.

Between 2025 and 2027, China's CO_2 emissions from electricity generation are projected to grow more slowly, by an average of 0.2% annually, as the acceleration in clean energy sources – renewables and nuclear – constrain coal-fired generation, and despite the significant gains expected in electricity consumption. Over the same period, India is forecast to see a 2% annual increase in emissions on average. By contrast, emissions from electricity generation in the European Union are projected to post a sharp contraction, declining by approximately 9% annually, while the United States is expected to achieve a reduction of around 2% annually.

CO_2 emissions from electricity generation in selected regions, 2015-2027



Note: Data for 2025-2027 are forecast values.

Global CO_2 intensity continues to decline as the share of clean energy sources expands

Global emissions intensity from electricity generation is on a sharply contracting trend, with a record 3% reduction in 2024 compared to 1% in 2023. This improvement reflects the rapid growth in renewable energy and nuclear electricity production relative to rising demand. By 2027, emissions intensity is forecast to fall significantly in major regions, with reductions in the European Union, China, the United States, and India all contributing to the global trend. Over the forecast period of 2025-2027, global CO_2 intensity is expected to fall by an average of 3.6% annually, declining from 445 g CO_2/kWh in 2024 to 400 g CO_2/kWh in 2027.

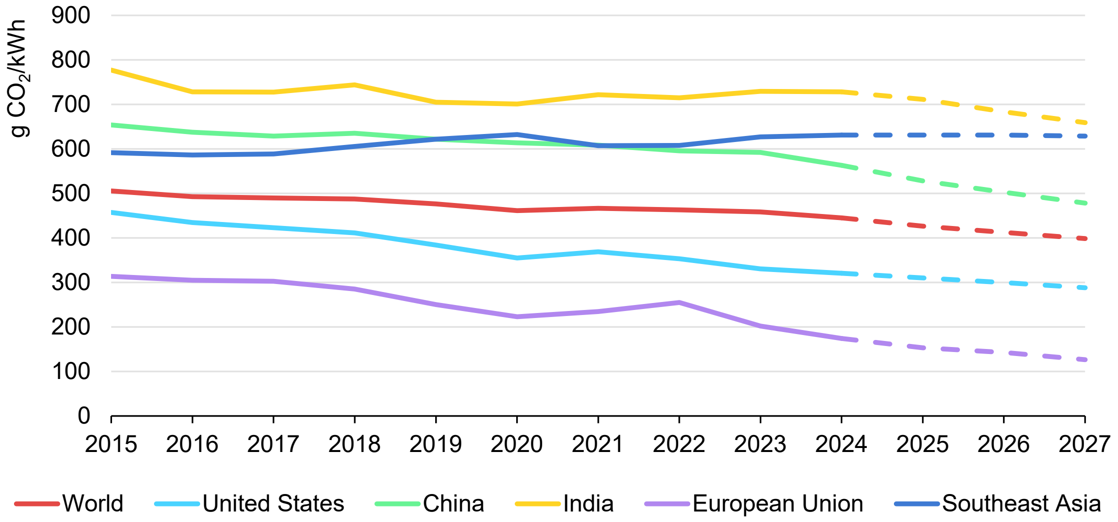
China accounted for a substantial share of the global decline in 2024, with emissions intensity of power generation falling by 5% y-o-y. This was supported by a recovery in hydropower generation and significant expansions in solar and wind power. Over the outlook period, emissions intensity in China is projected to decrease by an average 5.3% annually, reaching 480 g CO_2/kWh by 2027, down from 565 g CO_2/kWh in 2024.

India saw a modest decrease in emissions intensity of 0.1% in 2024, however, it is expected to decline by a stronger 3.3% annually between 2025 and 2027, led by substantial increases in solar photovoltaic installations, followed by hydropower and wind power generation. By 2027, India's emissions intensity is forecast to fall to 660 g CO_2/kWh from 730 g CO_2/kWh in 2024.

The **United States** experienced a 2.9% reduction in emissions intensity in 2024, supported by the ongoing shift from coal to renewables and natural gas. Over the forecast period, emissions intensity is expected to decrease by 3.5% annually, from 320 g CO_2/kWh in 2024 to 290 g CO_2/kWh in 2027.

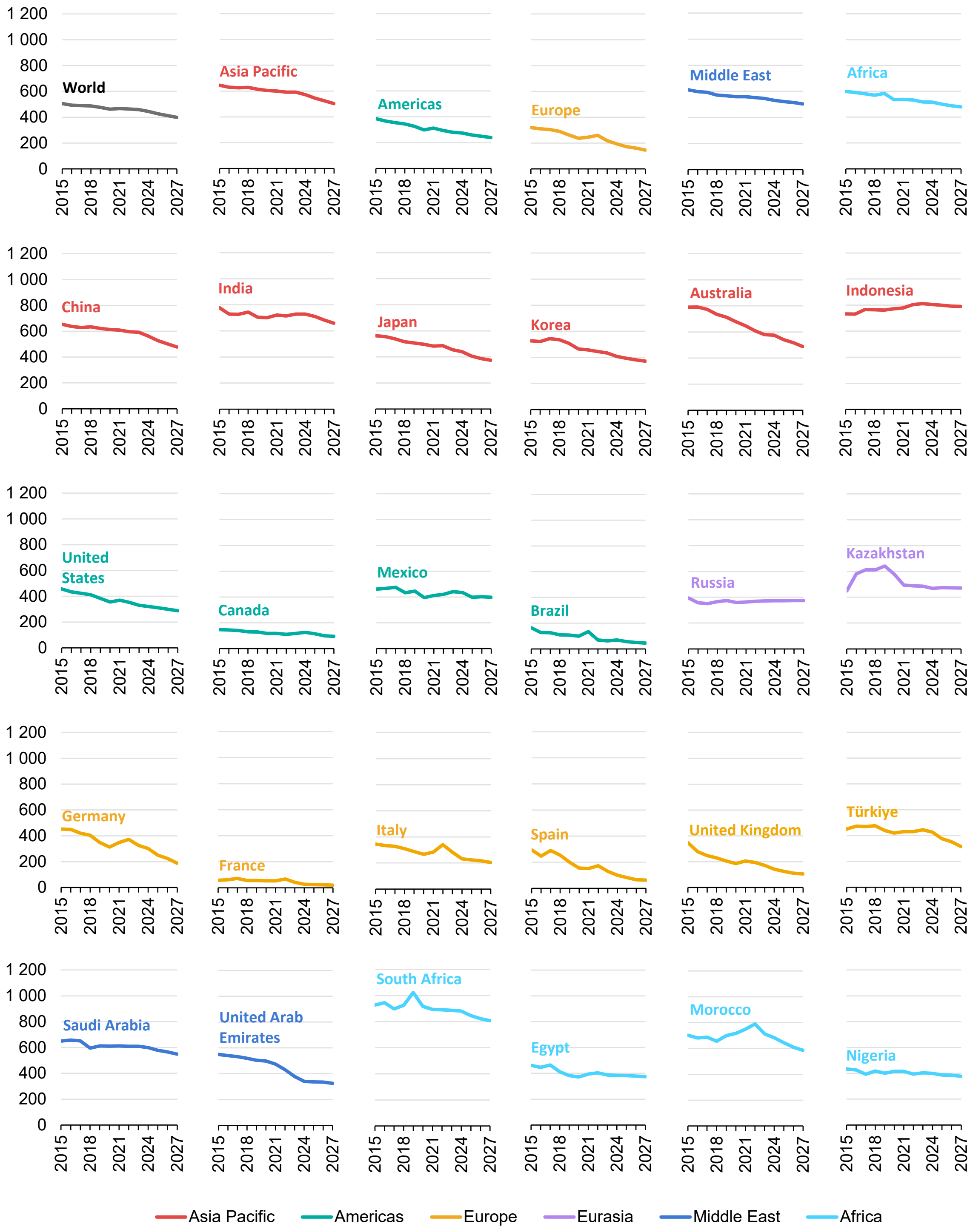
The **European Union** recorded the most significant relative decline in emissions intensity in 2024, with a 14% reduction driven by a sharp decrease in coal-fired power generation, which fell 15%. Growth in generation from clean energy sources also played a pivotal role. Over the outlook period, emissions intensity in the European Union is forecast to fall by about 10% annually on average, the fastest among major regions. By 2027, emissions intensity is expected to reach 130 g CO_2/kWh, down from 175 g CO_2/kWh in 2024. EU-ETS spot prices declined from an average of EUR 85/t CO_2 in 2023 to about EUR 65/t CO_2 in 2024. Futures prices for 2027 indicate a higher price level around EUR 80/t CO_2.

CO2 intensity of electricity generation in selected regions, 2015-2027



Notes: The CO_2 intensity is calculated as total CO_2 emissions divided by total generation. 2025-2027 are forecast values.

CO_2 intensity of electricity generation in the world, by selected countries and regions (g CO_2/kWh), 2015-2027



Notes: The CO_2 intensity is calculated as total CO_2 emissions divided by total generation. 2025-2027 are forecast values

Prices: Wholesale trends diverge, while negative pricing increases

Understanding cost drivers of grid tariffs is important as grids are poised to expand

Wholesale electricity prices declined further in many countries in 2024, following the sharp contractions in 2023. This downward trajectory largely tracked the fall in global energy commodity prices, but in some regions local market issues dictated diverging trends. The European Union, India, the United Kingdom and the United States all posted around 20% lower wholesale electricity prices on average in 2024 compared to previous year. Nevertheless, prices in these regions, with the exception of the United States, are still significantly above the pre-Covid levels.

At the same time, markets across different regions have been seeing an increasing occurrence in negative wholesale electricity prices. While they are not a dominant feature of many wholesale markets, their rising frequency warrants analysis to better understand the underlying causes and shortcomings in system flexibility. This year's report therefore throws a spotlight on negative electricity prices and explores in-depth the issues affecting this phenomenon (see *Spotlight: Negative electricity prices are becoming more frequent in some markets*).

As energy transitions progress, the overall cost of electricity generation is reduced as low-emissions technologies become ever cheaper and replace fossil fuel power. However, while the wholesale cost component declines, the grid tariff component on consumer electricity bills are expected to rise due to expanding electrification and further renewables integration. This makes understanding the cost drivers of the grid tariffs and the associated regulatory frameworks essential, which is also discussed in a dedicated section of this chapter (see *Managing upward pressure on grid tariffs is essential for an affordable energy transition*).

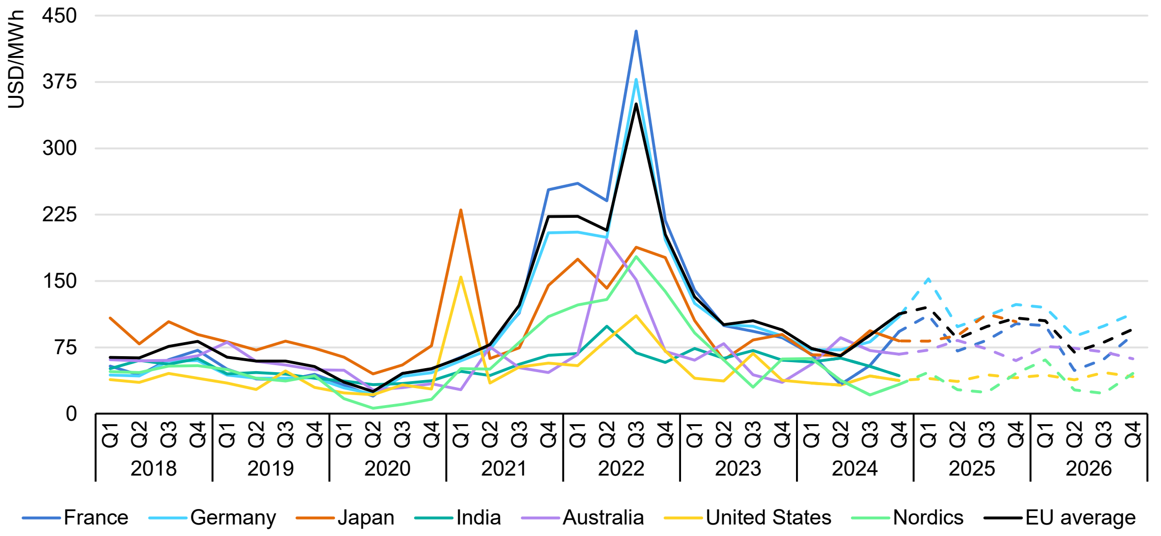
Wide wholesale price gap between the EU and the US remains but could narrow in 2026

The average EU wholesale electricity prices were still more than twice (+130%) the US level in 2024, with only a slight narrowing of the spread compared to 140% in 2023. Current futures prices indicate a similar spread of 160% in 2025, and a narrowing to 105% in 2026. While a much smaller difference than in 2022, when

EU prices were 210% higher than in the United States, it is still well above the pre-Covid difference of around 70%.

The **EU** electricity price in 2024 stood at around an average of USD 85/MWh, marking a 20% y-o-y reduction. Despite this decline, prices remained more than 40% higher than the 2019 average of USD 60/MWh. The first half of 2024 saw a pronounced decrease, with prices averaging around USD 70MWh, 40% lower than in H1 2023. By contrast, the second half of the year posted a 1% y-o-y increase, largely due to upward pressure from rising gas prices. Overall, increased wind and solar power generation, a recovery in French nuclear power and rebounding hydropower, alongside lower coal, gas and CO_2 prices, contributed to the year-on-year reduction in EU wholesale electricity prices in 2024.

Quarterly average wholesale prices for selected regions, 2018-2026



Notes: Prices for Australia and the United States are calculated as the demand-weighted average of the available prices in 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 (2025), SMARD.de; AEMO (2025), Aggregated price and demand data; U.S. EIA (2025), Short-Term Energy Outlook, January 2025 IEX (2025), Area Prices; EEX (2025), Power Futures; ASX (2025), Electricity Futures © ASX Limited ABN 98 008 624 691 (ASX) 2020. 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: 31 January 2025.

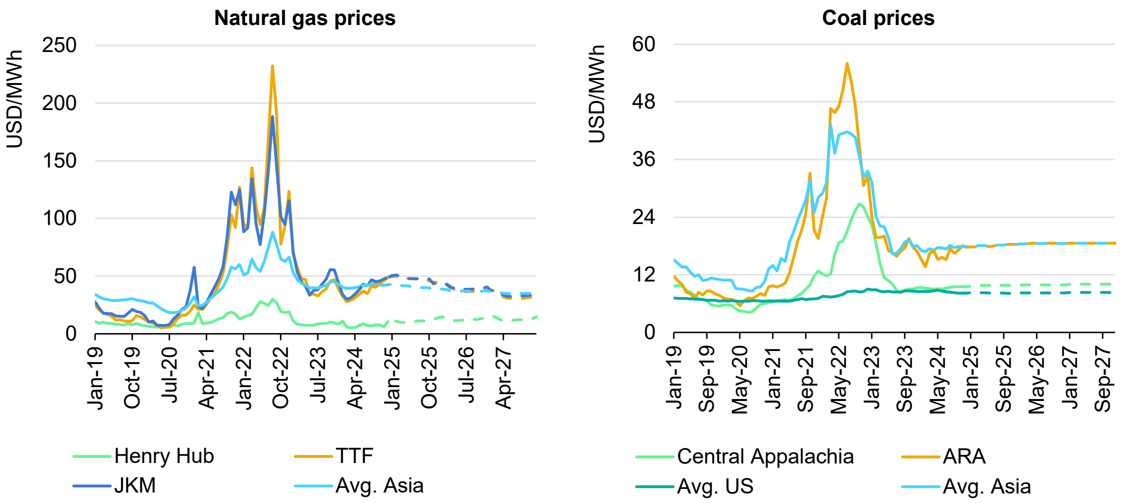
In 2024, wholesale price spreads between Germany and France averaged around EUR 20/MWh. In addition to diverging market dynamics between the two countries, the unavailabilities on the eastern interconnection in France, which limited export capacities to Germany, also affected the spread. Strong hydropower and nuclear generation in France also contributed to a 40% y-o-y reduction in wholesale electricity prices, resulting in an average price of USD 62/MWh. Futures prices indicate a German-French annual price spread of about USD 30/MWh.

The **Nordics** remained the region with the lowest prices in Europe in 2024, with the average wholesale electricity price about USD 40/MWh, down 40% y-o-y, and similar to pre-pandemic levels. The decline was supported by strong hydropower output amid high reservoir levels resulting from substantial autumn precipitation. Prices were comparably more volatile in Q4 2024 in the face of low wind generation and colder temperatures. While seasonal spreads are observed in the futures prices, annual average wholesale prices remain at similar levels to 2024.

In the **United States**, wholesale electricity prices continued their downward trend in 2024, to an average USD 37/MWh (-20% y-o-y) and close to pre-Covid levels. The decline was amid lower natural gas prices, with the average Henry Hub spot price in 2024 USD 2.2/MMBtu, 14% less than in 2023. Weaker prices stemmed from increased natural gas production and warm temperatures, which limited the withdrawal of supplies from storage.

Electricity prices surged during short-term extreme weather events in 2024. Heatwaves drove boosted electricity demand, leading to higher spot prices in Southern California and in the southwestern region of the United States in July 2024 and early October 2024. Frozen natural gas wells contributed to spikes in electricity prices in New York and New England regions in early 2024. Over the outlook period, projections from the Energy Information Administration's (EIA) Short-term Energy Outlook (STEO) posted a stable price level at an average of around USD 40/MWh for 2025. Slightly higher summer prices in Q3 2025 of USD 44/MWh suggest a price premium that reflects the possibility of heatwaves.

Prices for energy commodities in selected markets, 2019-2027



Notes: The 2025-2027 prices are based on available forward prices as of January 2025. Average natural gas prices in Asia reflect estimated LNG import prices, including via oil-indexed LNG contracts and spot prices.
Source: EIA (2025), STEO, January 2025.

Japan's wholesale electricity prices in 2024 declined slightly by 10% y-o-y, averaging USD 77/MWh. In H1 2024, prices were lower at an average USD 66/MWh amid weaker LNG prices, a mild winter, and the gradual restart of nuclear reactors. However, summer 2024 experienced volatile high electricity prices due to soaring temperatures. In the second half of the year, prices significantly increased to an average USD 88/MWh due to colder weather, particularly in the eastern and northern regions of Japan. Despite these seasonal shifts, sufficient LNG stocks helped moderate price volatility. However, the depreciation of the yen added upward pressure on electricity prices, as Japan sources most energy commodities in US dollars. Futures show rising wholesale electricity prices throughout 2025, averaging slightly below USD 100/MWh.

Wholesale electricity prices in **Australia** averaged USD 70/MWh in 2024, 30% above the 2023 level, but 40% below the 2022 average. While prices in H1 2024 were comparable to the same period in 2023, wholesale prices in H2 2024 surged by 80% compared to H2 2023. In Q3 2024, eastern Australia saw a cold winter that led to record-high demand in Queensland and Victoria during July. On the country's eastern coast, gas prices averaged 20% higher in Q3 2024 compared to the same quarter in 2023 due to more expensive gas-fired generation. Tasmania's hydropower dropped by more than 30% in Q3 2024 compared with the same period year prior, and it was replaced by higher gas use and imports from Victoria, contributing to a 280% rise in average wholesale electricity prices compared to Q3 2023. Frequent network outages between late July and early August severely limited electricity exports from Victoria to South Australia, significantly contributing to South Australia recording the highest regional quarterly average spot price in the country's National Electricity Market (NEM). Meanwhile, West Australia's Q3 2024 wholesale prices were down 10% y-o-y. Electricity futures indicate relatively stable price levels of around USD 70/MWh throughout 2025.

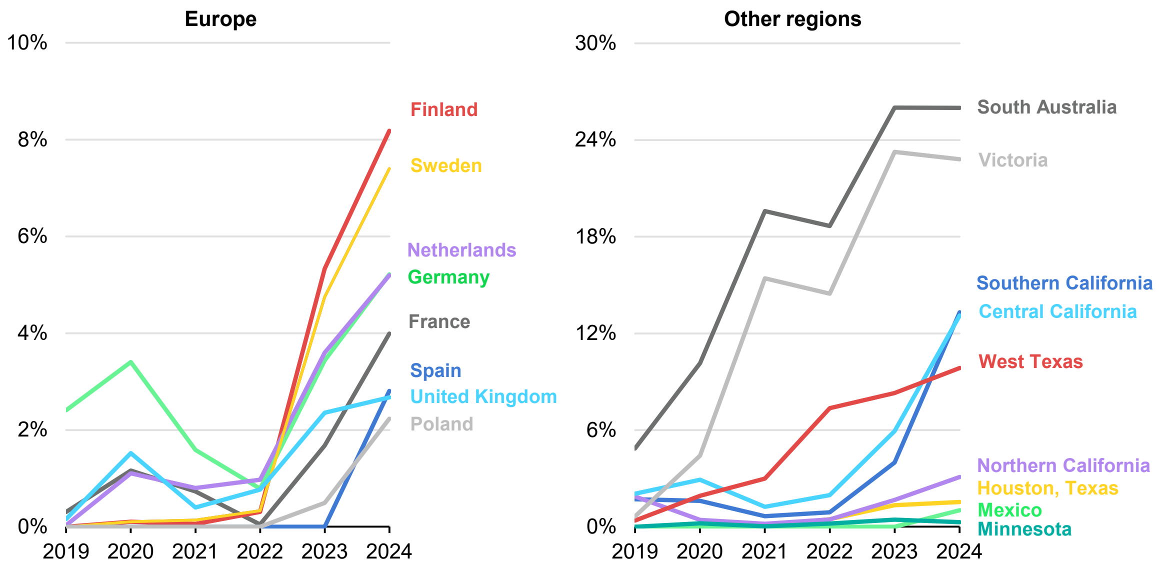
In **India**, electricity prices fell 20% y-o-y in 2024, averaging USD 55/MWh. Despite this decline, prices remained 25% higher than the 2019 average, driven by surging electricity demand fuelled by economic growth and increased cooling needs during the longest heatwave in the country's history recorded in June 2024. Government and regulatory measures played a critical role in moderating prices. These included selling surplus requisitioned electricity on power exchanges, increasing fuel supplies and ensuring higher generation, which enhanced market liquidity and exerted downward pressure on prices. Hydropower output also rebounded in 2024, recovering from the weaker performance seen in 2023, which helped meet increased demand.

Spotlight: Negative prices highlight the need for more flexibility in supply and demand

Though still relatively uncommon in many power markets on a global basis, some regions are seeing an increase in the occurrence of negative wholesale prices in recent years. There are various reasons why negative prices may emerge in some markets where they are allowed, but broadly they 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. The magnitude and duration of negative price occurrences vary across countries and regions, as they are subject to market conditions.

In South Australia, negative prices accounted for about 25% of the hours on average annually in both 2023 and 2024. Across the world in southern California, the share of hours with negative prices surged to 15% in 2024, up from only 4% a year earlier. The number of hours with a negative wholesale electricity price has been increasing in Europe since 2022. Finland led the continent with the highest number of negatively priced hours in 2024, at 8% of the time (700 hours). Similarly, the occurrence of negative prices in Sweden rose from 5% in 2023 to 7% in 2024, in the Netherlands from 4% to 5%, and in Germany from 3% to 5%.

Fraction of negative hourly wholesale electricity prices in selected regions, 2019-2024



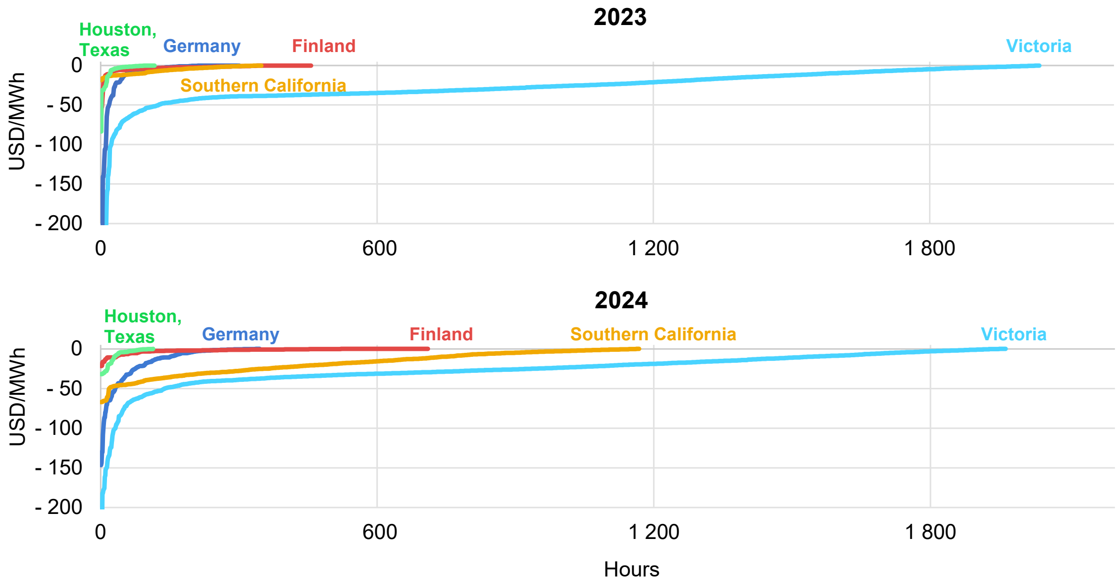
Notes: Southern California corresponds to area SP15 in the state's zonal regions, Central California to area ZP26 and Northern California to area NP15. In Spain, negative electricity prices on the day-ahead market were permitted in December 2023 following the implementation of updated rules on the operation of electricity markets. In Italy, negative prices were previously not allowed, but this changed in January 2025 with the implementation of the Testo Integrato del Dispacciamento Elettrico (TIDE) reform. For South Australia and Victoria, five-minute interval prices were converted to hourly averages to enable comparison.

Source: IEA Real-Time Electricity Tracker (2025)

Despite the growth trend, most European markets had negative electricity prices less than 5% of the time in 2024. In other markets across the world where regulations allow negative electricity prices, this share is even less. For example, in Houston, Texas it was slightly above 1% in 2024, while in some parts of Mexico it was less than 1% on average. Negative prices are not yet a dominant feature in most markets, but their strong growth trend in various regions in recent years is highlighting the growing need for more flexibility in electricity supply and demand. Negative prices can serve in some cases as an incentive for the adoption of storage solutions and demand-side response. However, negative prices alone may not suffice for increased system flexibility. Adequate regulatory frameworks, market designs and tariff structures are essential for flexibility in the system.

Even though negative prices are becoming more common, compared to the average wholesale electricity prices, they have generally remained largely within a moderate range of USD -1/MWh to USD -30/MWh, with extreme low prices rare. In 2024, for example, they averaged USD -2/MWh in Finland, USD -7/MWh in Houston, Texas, USD -12/MWh in Germany, USD -25/MWh in Victoria and USD -30/MWh in South Australia. However, the vast majority of negative prices were only slightly below zero in most regions. For comparison, the average wholesale electricity price in 2024 in Victoria was USD 80/MWh and in Germany around USD 100/MWh.

Duration curves for negative wholesale electricity prices in selected regions, 2023-2024



Notes: Southern California corresponds to the SP15 area. Five-minute price intervals in Victoria were converted to hourly averages for comparison. The y-axes of the figures are limited to USD -200/MWh for ease of visual interpretation. Following the guidance decision from the EU regulator Agency for the Cooperation of Energy Regulators (ACER) in January 2023, the minimum allowed clearing prices for day-ahead markets across Europe have been standardised at EUR -500/MWh. On 24 November 2023, prices in Finland reached the lowest limit of EUR -500/MWh for ten hours due to a bidding error. Excluding that, the lowest negative price was EUR -60/MWh. In 2023, the lowest negative price in Houston, Texas was USD -84/MWh, in Southern California USD -19/MWh, in Germany EUR -258/MWh, and in Victoria AUD -461/MWh. In 2024, the lowest negative price in Finland was EUR -20/MWh, in Houston, Texas USD -32/MWh, in Southern California USD -67/MWh, in Germany EUR -136/MWh, and in Victoria AUD -382/MWh.

Source: IEA Real-Time Electricity Tracker (2025)

However, there is a growing trend of extended periods with slightly negative or very low prices, particularly during times of subdued electricity demand and high variable renewable energy (VRE) generation, such as when there is abundant solar PV output during midday in spring or summer in various regions but lower demand. In the markets we analysed in our July 2024 mid-year update, the duration of negative price events tends to increase when there is a higher proportion of solar PV in the electricity mix. In Southern California, from June 2023 to May 2024, 80% of the events with consecutive negative prices lasted over eight hours, 60%[16] in South Australia, and 40% in Germany. While inflexible rooftop solar PV is a major contributor to this trend in these regions, it also occurs in conjunction with the overall limited flexibility of supply and demand in the system.

How do negative prices occur and what does it mean for consumers?

Negative prices can arise in various markets under specific conditions, typically stemming from inflexible supply and demand as well as lack of available storage. While energy markets – mainly electricity but also occasionally oil and gas – are a well-known example where such a phenomenon can occur, it also happens sometimes in such diverse markets as agriculture and water. Due to the unique characteristics of electricity markets, negative prices can be much more common. Supply and demand must be continuously balanced on a very short timescale in the face of limited storage capacity and insufficient demand-side flexibility. Additionally, certain generation sources face technical, economic, contractual, or regulatory constraints. This can lead to situations where all the demand is met by producers that prefer to pay others to take their energy rather than stopping production.

Consumers can benefit from negative electricity prices if these price signals reach them. Large energy consumers in the industrial and service sectors, who have direct access to wholesale prices, for example, can take advantage of negative prices by shifting their consumption accordingly. Negative prices can also be a big opportunity for flexible retail consumers. Consumers that have time-of-use or dynamic tariffs can reap benefits by shifting their consumption to low-price periods, such as charging electric vehicles and household batteries or to store hot water during midday when prices are more likely to be lower or negative. The growing adoption of smart meters offers an opportunity for well-designed tariffs to encourage price-responsive behaviour and better align retail consumption with system requirements. Adequately designed time-of-use tariffs especially offer great potential in this regard due to their relatively simple nature.

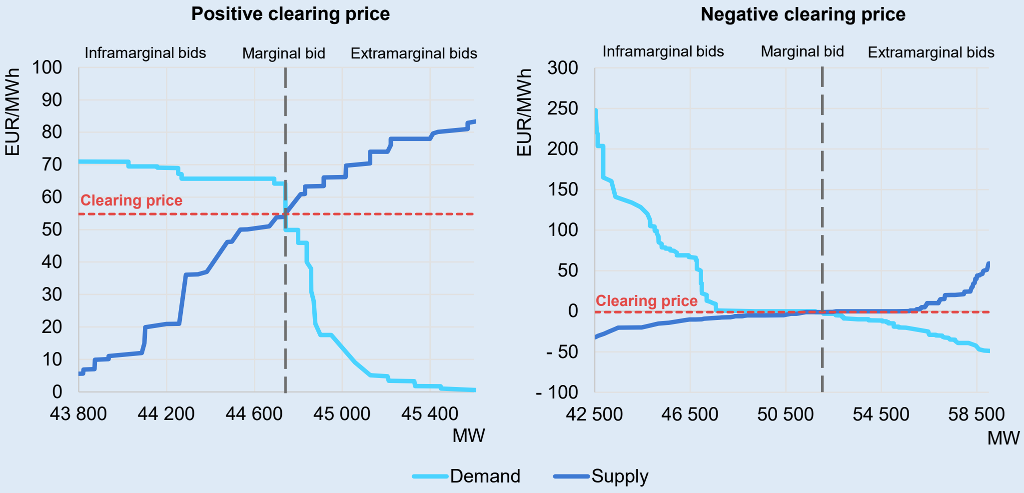
[16] Five-minute prices were averaged to an hourly level to allow for cross-country comparison.

How prices are formed on wholesale electricity markets

To understand the formation of negative prices, it is important to know how wholesale electricity prices are set in the first place. One of the most common spot market structure is a day-ahead electricity market – where the dispatch schedule of power plants for the following day is determined. There are also real-time electricity spot markets where electricity is traded much closer to the time of delivery, for example in intervals as short as five minutes.

On the spot markets, for each delivery period, generators submit their bids with an available quantity and price while consumers submit their bids as demanded quantity and the price they are willing to pay. Based on these parameters, the market operator establishes for each delivery interval a demand curve and a supply curve. The bids are sorted from lowest to the highest offered price for the supply curve, as the aim is to meet the demand at least cost. The opposite sorting order applies to the demand curve. The intersection of these two curves yields the market clearing price. This price applies to all cleared buyers and sellers. The generator that sets the clearing price is called the marginal generator. Those with lower priced bids than the marginal generator in the supply curve are called infra-marginal generators and produce while receiving the clearing price, whereas those with more expensive bids than the marginal generator do not produce and not get the clearing price, being referred to as the extra-marginal generators. This type of market is commonly referred to as a uniform-price auction market.

Representative aggregated bidding curves on the day-ahead spot electricity market



Notes: The curves for the figure on the left are for the German hourly day-ahead market for the delivery period 23 December 2024 at 13:00-14:00 and the one on the right for 1 January 2025 at 14:00-15:00. The data is plotted for the shown range for better visual representation but there are also significant amount of bids beyond these ranges. Aggregated bid curves are based on aggregated demand and supply curves. The volumes of the curves also include realised supply and demand block volumes as well as import and export flows.

Source: IEA analysis based on aggregated bidding curve data from Nord Pool.

Under perfect competition conditions, generators are incentivised to bid at a price which reflects their marginal cost[17]. This is because if a generator decides to offer at a price above this, other producers who bid at their true marginal costs can meet the demand instead, as they are cheaper in the supply curve (becoming infra-marginal). The producer who bids above its marginal cost, therefore, risks staying out of the market (becoming extra-marginal) if it has a higher priced bid than the most expensive producer that was cleared (marginal) and which set the market clearing price.

Certain technical, contractual and regulatory inflexibilities and other out of market commitments can result in generators bidding negatively to remain in the market even when the spot price (i.e. market clearing price) is negative. As the positive clearing price applies to all buyers and sellers, the negative clearing price also applies to all buyers and sellers. Therefore, all the infra-marginal generators have lower (more negative) bids than the clearing price produce and receive the negative clearing price, meaning that they pay to produce. Infra-marginal generators during a negative price period can thus be considered to contribute to the negative price formation.

Consumers, on the other hand, get paid to consume during negative prices. Negative prices, therefore, can serve as an important market signal, encouraging producers who can to reduce production, and consumers to increase consumption.

Multiple factors can contribute to negative price formation on wholesale electricity markets

Numerous factors can often act simultaneously to cause negative wholesale prices, and they affect the system in a collective manner. A systematic grouping of the main drivers behind negative prices are provided as follows:

Technical inflexibilities: For some thermal power plants, shutting down and restarting can be slow and costly due to technical inflexibilities. In these cases, the operators may prefer to pay to stay operational during periods of low electricity prices that are below their marginal costs. The technical minimum load levels of thermal plants determine to what extent they can reduce their generation while staying on and plays an important role when these plants are running during negative electricity prices. Rooftop solar PV modules and older generation wind turbines are also associated with technical inflexibilities and are typically not economically curtailed, making them unresponsive to price signals.

[17] Marginal cost of a power plant corresponds the additional cost it incurs for producing one additional unit of electricity. This is a function of fuel cost, plant efficiency, cost of CO_2 (if applicable), and variable operation and maintenance costs. In addition, the cost of starting up and ramping the plant may also be considered in a power plant's bid on the market.

Regulatory and contractual inflexibilities: Some support schemes and contract structures dampen or exclude short-term market price signals. This can apply to both VRE and thermal generators. Schemes that incentivise maximising sent-out volume such as feed-in tariffs (FiT), certificates of origin, or various production-based forms of Contracts for Differences (CfDs) can lead generators to produce during negative prices. Capacity payments, fossil fuel subsidies and fixed-price or long-term contracts can introduce inflexibilities in the market. These mechanisms may incentivise generators to continue producing electricity even when market prices drop below zero.

Commitments to other essential services: Some conventional generators cannot stop production and need to continue generating, which can be referred to as "must-run" capacities, such as combined heat and power (CHP) plants providing process heat to industry or heat to district heating networks. Some CHP plants can base their dispatch decisions on providing heat and the revenues associated with that, rather than focusing solely on electricity prices. Some conventional generators may run despite negative energy prices to provide ancillary services to the system[18]. A generator making a loss on the spot market may nevertheless prefer to run if its revenues on the ancillary services markets exceed these losses. In some cases, the system operator may obligate the generator to run to provide certain services to the system such as inertia or voltage stability, or for constraint management due to grid limitations.

Other factors: Cross-border effects and imports/exports also play a role. A market area with negative prices that is exporting to a neighbouring market can lower the prices in the importing region and contribute to negative prices in that area. It should be noted that interconnections and import/exports increase total welfare overall, and in this specific case, they allow the consumers of the importing region to have access to cheaper electricity from the exporting region. Also, grid congestion or limited availability (or lack) of electricity import and export capacity between market areas can exacerbate negative prices.

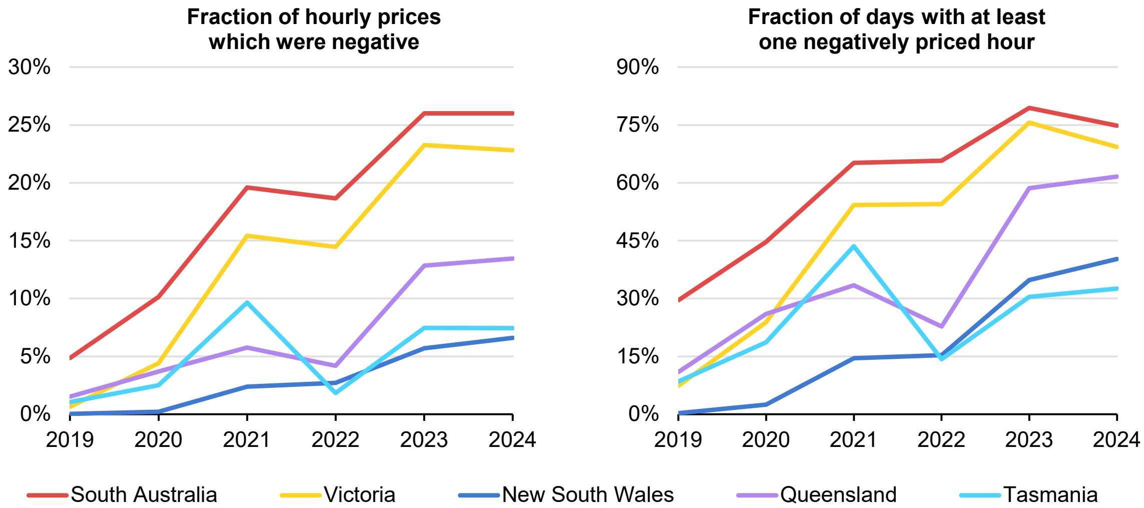
A case study: Drivers of negative electricity prices in Australia's National Electricity Market

The case of Australia's NEM is particularly relevant since it has the highest level of negative electricity price occurrences in the world. However, as previously discussed, having a high number of negative prices is not necessarily bad, as they act as strong price signals for incentivising flexibility, in particular in batteries and

[18]Ancillary services are essential functions to maintain the proper operation, stability and reliability of the power grid. These services involve continuous adjustments to keep frequency, voltage and power load within specified limits, enabling a reliable power supply. Key aspects include frequency control, voltage management, supply restoration after blackouts, and operational management.

demand-side response. In NEM's South Australia region, wholesale electricity prices have been negative 25% of the time since 2023. Neighbouring Victoria, the only other market with which South Australia is directly interconnected, also recorded a share of negative prices of over 20% in the same period. Queensland has also been catching up to South Australia and Victoria on negative pricing. It is now more unusual to have a day in these regions without any negative prices, as 60-70% of the days over 2023-2024 had at least one negatively priced hour[19].

Negative wholesale price trends in Australia's National Electricity Market, 2019-2024



Source: IEA Real-Time Electricity Tracker (2025)

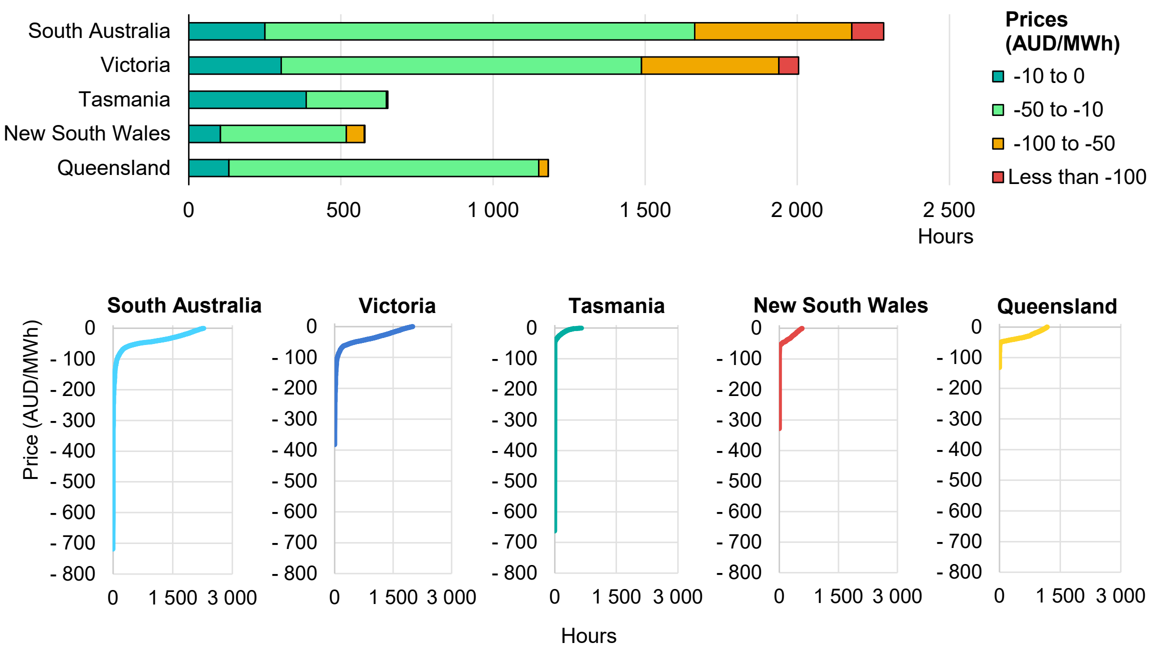
The NEM is a liberalised energy-only market[20], like a significant number of other power markets in the world, which means it does not include a separate function for providing payments for investment in capacity. Total power generation in 2024 was 217 TWh, corresponding to about 80% of Australia's electricity consumption. The NEM covers five different regions that are interconnected, with prices on the wholesale market determined for each region at five-minute trading intervals. Similar to the interconnected European countries, regions in the NEM have varying electricity generation mixes. Some regions have very high shares of VRE, such as South Australia with around 75% (comparable to Denmark nearing 70%), while others have high shares of thermal generation, such as Queensland with 60% coal (comparable to Poland with 60% coal).

[19] Australia's NEM runs on five-minute trading intervals. These statistics are based on hourly averages.
[20] Some examples of energy-only electricity markets include Germany, Denmark, Sweden, Norway and Finland, Türkiye in Europe, Texas (ERCOT) in the United States, and Alberta in Canada. In some energy only markets, capacity remuneration mechanisms such as strategic reserves or resource adequacy programs also exist additionally.

At the same time, compared to many countries in Europe, the NEM regions are less interconnected. For example, while Germany is connected to ten other neighbouring market areas, Victoria is connected with only three other areas, New South Wales with two, and South Australia, Tasmania and Queensland with only one. As power markets across the world tend to differ in their designs and operational procedures, the NEM can also differ from some other markets in other countries *(see the box below for an overview of how the NEM operates and how the prices are set*).

Taking into account the similarities as well as the differences across different markets, the NEM can nevertheless serve as a useful case study to gain insights into the different drivers of negative prices and provide concrete examples to the aspects mentioned in the previous section. These can also be relevant for other countries and regions where the occurrence of negative prices is increasing.

Number of negative hourly electricity prices and their duration curves in NEM regions in Australia in 2024

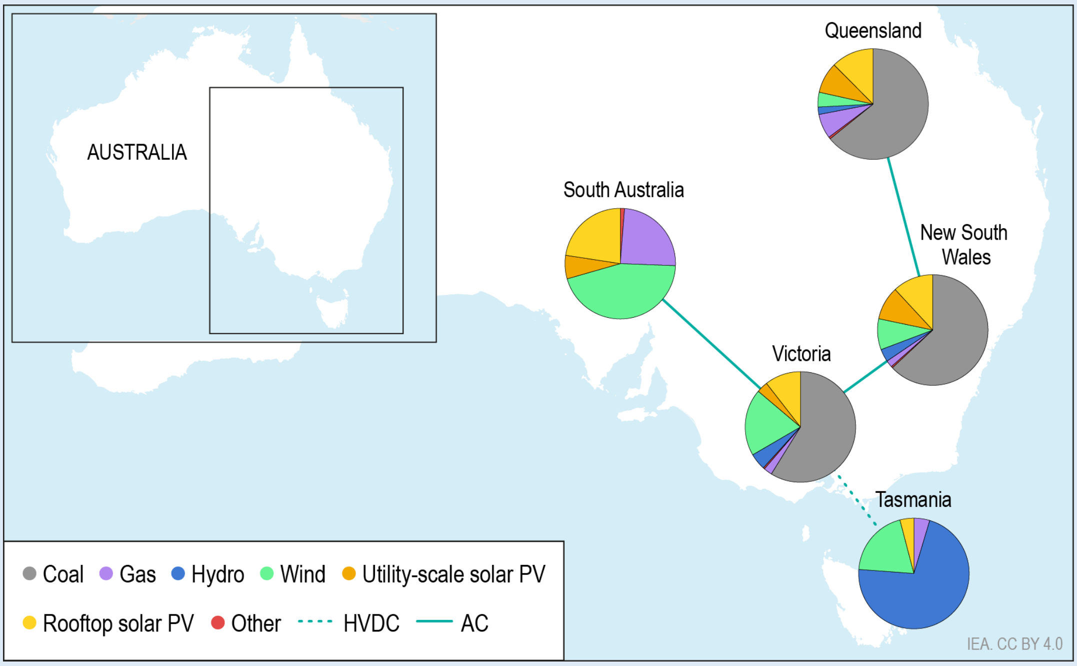


Notes: Australia's NEM runs on five-minute trading intervals. The plotted values are based on hourly averages.
Source: IEA Real-Time Electricity Tracker (2025)

How are electricity prices set on Australia's National Electricity Market?

The NEM is a wholesale real-time market for generators and retailers to trade electricity in Australia. For each five-minute interval, generators submit bids specifying how much electricity they can supply across ten price bands. These bids are compiled into a bid stack, ranking offers from cheapest to most expensive. Prices are set for each five-minute trading interval by a linear optimisation programme called the NEM Dispatch Engine (NEMDE), which minimises the selected generator offers subject to demand and transmission constraints. Generators can adjust their bids up to a few seconds before dispatch through rebidding, often responding to changing market conditions.

Overview of the NEM regions and their generation mix in 2024



Notes: The red lines represent the simplified interconnectivity between the regions and do not stand for the individual number of interconnectors. The five NEM regions are linked via six interconnectors, where in addition to the DC link between Tasmania and Victoria, there is also a DC link between Victoria and South Australia and another one between New South Wales and Queensland.

The basic principle is that the price in each interval is equal to the bid of the marginal generator in a given region. However, this describes how the price was actually set only for a small portion of the time. For example, prices were set like this only 24% of the time in South Australia and 24% in Victoria during 2024. The reality is more complex, as price-setting is often influenced by differences in generation mix across the regions, grid constraints, and co-optimisation with ancillary services.

One aspect that adds an additional layer of complexity is imports and exports from and to neighbouring states. Because of this, electricity prices are not always set locally. For example, South Australia's prices are often determined by generators in other regions, like coal plants in Victoria, due to economic dispatch considerations. Even though South Australia no longer has coal-fired power, more than 40% of its wholesale electricity prices are set in this way. This is because, if it is cheaper to import coal power from Victoria to South Australia than to run local gas generators, then the Australian Energy Market Operator (AEMO) will do so, and the resulting price in South Australia will equal the marginal price of coal in Victoria, adjusted for transmission losses.

AEMO also needs to consider grid constraints, including managing inertia, adhering to transmission limits and providing voltage stability. These constraints can force some generators to operate out of merit order, meaning they can generate power despite not being the cheapest option. The spot price can then be set by multiple generators, often resulting in a weighted average of local and remote generation costs.

Ancillary services can also cause the spot price to deviate from the simple marginal cost-based example. In the NEM, frequency control and ancillary services (FCAS) are co-optimised with energy dispatch to minimise total system costs. This means that AEMO's dispatch engine NEMDE may decide to dispatch a more expensive generator (that is also providing ancillary services) on the energy supply curve if the reduction in ancillary services costs offsets the increase in energy costs. For example, South Australia, Victoria and Tasmania saw spot prices set through co-optimisation by AEMO 14%, 13% and 43% of the time, respectively, in 2024. Apart from this, generators themselves may accept energy prices below their marginal costs and bid in the energy market accordingly if their revenues from ancillary services offset the loss on the energy market.

Generators submit bids in price-volume pairs, but market dynamics often lead to strategic rebidding. For example, wind and solar generators facing transmission constraints often bid their output to the minimum allowed price (AUD -1 000/MWh) to avoid curtailment even when prices are in the normal positive range. Then during intervals when prices are forecast to be negative, generators adjust their bids back up to, or above, their marginal cost. As for rooftop solar PV, it is treated as negative load, indirectly shifting prices downward by reducing operational demand.

Irrespective of which marginal generator specifically sets the negative clearing price, all the infra-marginal generators that produce during a negative price period can be considered to contribute to the negative price formation as discussed in the previous section in a more generalised setting. This principle also applies to the negative price formation in the NEM.

Inflexible thermal and VRE generators both contribute to negative prices in the NEM, with their shares varying by region

In an extensive analysis of AEMO's [public dataset](), we analysed the type of inflexibilities on the supply side that contribute to negative prices in the NEM.[21] For this purpose, we considered the breakdown of negatively-priced energy by volume, across different sets of generators. Infra-marginal generators during periods with negative prices are considered as contributing to negative price formation because they generally demonstrate a willingness to generate at the given negative price by bidding negatively.[22] Our results show that both thermal generators and renewable generators contribute to negative price formation, but this ratio differs significantly across the regions. For both types of generators, technical, regulatory and contractual inflexibilities are found to be relevant in influencing their decisions to produce during negative price periods.

In three out of the five states, namely Victoria, New South Wales and Queensland, coal-fired supply plays a substantial role in the occurrence of negative prices. Even though coal-fired plants react to negative prices and reduce their output to an extent, they still make a large share of the infra-marginal generation in these regions. Their shares in generation during negative price periods are about 30-40%, compared to the 60% average annual share of coal in electricity generation in these states.

In South Australia, negative electricity prices are mostly driven by VRE, which makes up 90% of the generation in these occurrences. Of this, more than one-third is inflexible rooftop solar PV, which continues to generate during negative prices irrespective of the price levels. The rest is utility-scale VRE, of which 70% can be classified as price-responsive based on our analysis of their bidding behaviour. This type of generators typically produce when prices are moderately negative (e.g. close to the negative of the green certificates price), but curtail or shutdown when prices decline further. By contrast, only 30% of the total utility-scale VRE generation is found to be unresponsive to prices. These consist of various volume-maximising utility-scale assets, likely due to production-based contracts or power purchase agreements requiring maximum output.

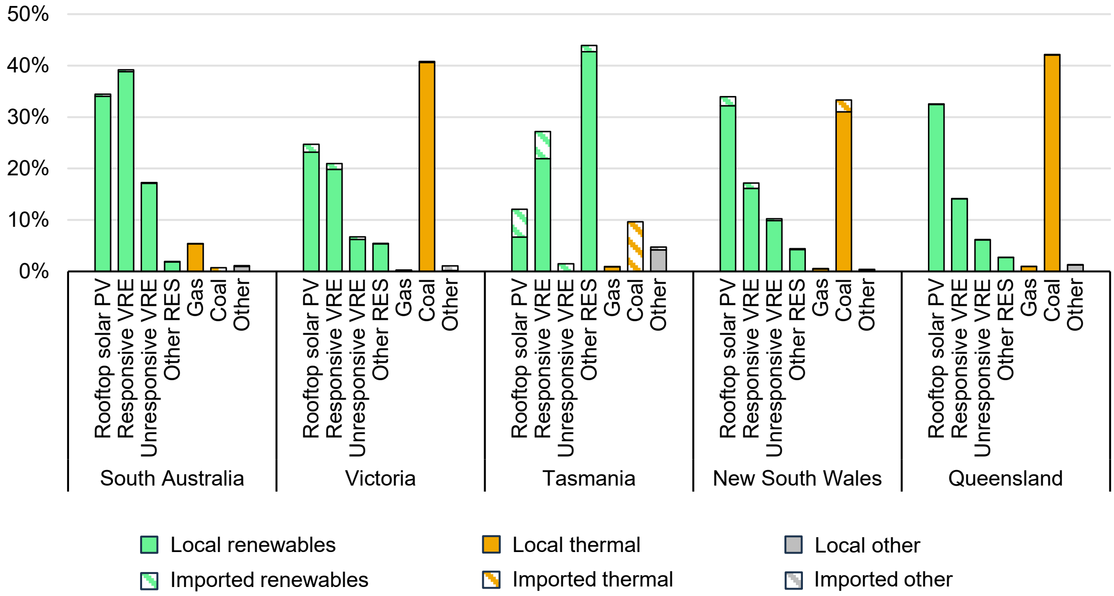
In other regions, the generation shares of price-responsive utility-scale VRE are about 15-20% and are consistently higher than the shares of unresponsive utility-scale VRE. Apart from these trends, across all NEM regions except Tasmania,

[21] Almost all of AEMO's data is publicly available. This includes prices, power levels of generators, inter-regional flows, constraints, and full bids data.

[22] Alternatively, if they had instead all bid positively, leaving only the one 'marginal' generator below zero, then the price would not have been negative

inflexible rooftop solar PV can be identified as a significant contributor to negative prices, having a share of 20-30% in generation during negative price periods.

Generation shares during negative price periods in the NEM wholesale electricity markets in Australia, 2024



Notes: The share of negatively-priced electricity generated by each fuel and generators' bidding behaviour based on historical bidding data were used to identify price-responsive and unresponsive generators. Unresponsive VRE refers to utility-scale renewable generators that do not alter their bidding behaviour in response to negative prices, and includes both wind and utility-scale solar PV. Inflexible rooftop solar PV generation is shown separately. Responsive denotes renewable generators that adjust their bidding behaviour based on the negative price level. These generators tend to produce when prices are moderately negative, but curtail or shut down when prices decline further. Other RES includes hydropower as well as renewable generators that cannot be clearly classified as either responsive or unresponsive to negative prices. Other encompasses reasons not classified by the shown categories. Imported energy was allocated based on the fuel mix of the immediate neighbouring (exporting) region, and rooftop solar was treated as generation rather than negative load. Each negatively-priced interval was weighted by the volume of electricity generated during that interval. For the analysis of bidding histories, generators were categorised as "set and forget" bidders that are mostly static or those that actively do rebidding. Some static bidders are unresponsive renewables, maximise volume by bidding at the price floor, likely due to production-based contracts or power purchase agreements requiring maximum output. Responsive renewable generators, on the other hand, adjust their bids based on the magnitude of negative price levels, suggesting strategies aligned with a slightly negative marginal cost, which can be influenced by certain support schemes.

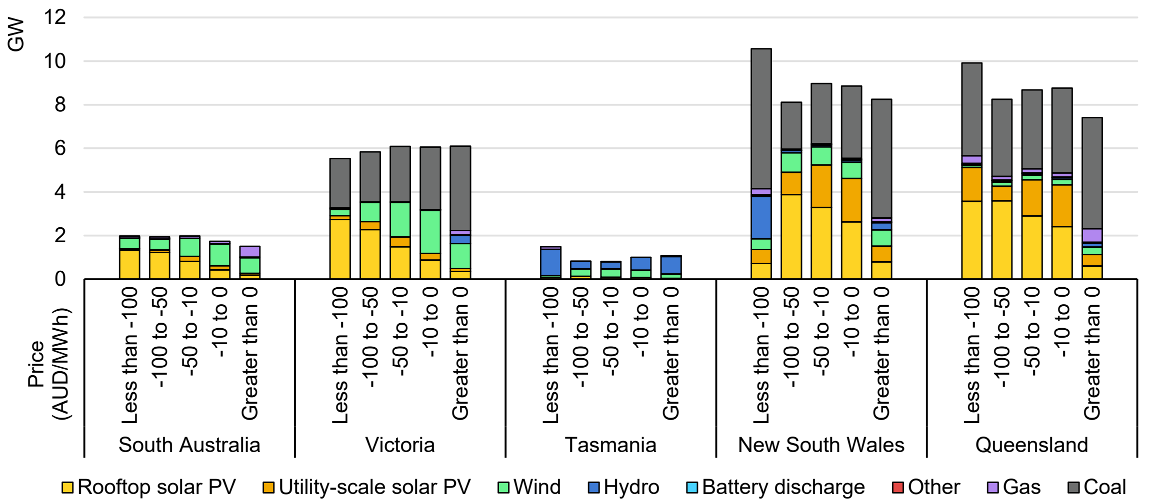
Source: IEA analysis based on data from AEMO.

In NEM regions with high shares of coal-fired generation, coal power continues to have a high output during negative prices

A variety of reasons can cause coal power plants to continue to generate at a relatively high output during negative prices in the NEM, but a major reason is technical inflexibility amid intertemporal constraints and certain portfolio considerations. Coal-fired power plants are typically constrained in their technical flexibility due to having higher minimum loads (e.g. around 25-40% for hard coal and 50-60% for lignite-fired plants) and lower ramping rates. As with many other generator types, the minimum generation requirements, efficiency losses during part-load operation and the cost of shutting down and starting influence their dispatch decisions on an intertemporal scale. This is also the case in the NEM.

Coal-fired generators in the NEM are largely part of vertically integrated generator-retailers and commonly hedge their retail and sold contract positions. Even though a power plant has hedged its position and locked in a price level, it may benefit by reducing its exposure to negative prices by, ideally, shutting down. However, because of the additional costs incurred due to limited technical flexibility during shutdown and restarting, instead generators tend to run at a lower or minimum load so that they can ramp up to maximum load over the evening peak.

Average annual electricity output during negative prices, NEM regions, Australia, 2024



Notes: The x-axis refers to wholesale electricity price thresholds in AUD/MWh. The analysis excludes imported power. In the analysed time period, New South Wales, Queensland and Tasmania had fewer than six hours of prices lower than AUD -100/MWh, hence the fuel breakdown there for this price interval does not have much explanatory power. South Australia and Tasmania do not have coal-fired power plants.

Even if coal-fired generators want to generate less power during negative prices, they may not be able to do so quickly enough, and as they ramp down, they continue to provide power. This can also occur with gas-fired generators, though they are generally associated with faster ramp rates. Other sources of inflexibility in thermal assets can be ancillary services provisions and other out-of-market commitments, though their contribution to negative prices in the NEM is estimated to be limited compared to technical inflexibilities.

There may be also other system-related factors that can result in thermal power plants running during negative prices. For example, about 7% of negatively-priced energy in South Australia in 2024 was from gas-fired generators with positive priced bids. They were dispatched out of merit order because of the frequent out-of-market directions and interventions by AEMO to keep a minimum amount of gas generation operational for electrical system strength (e.g. stability of the voltage waveform).

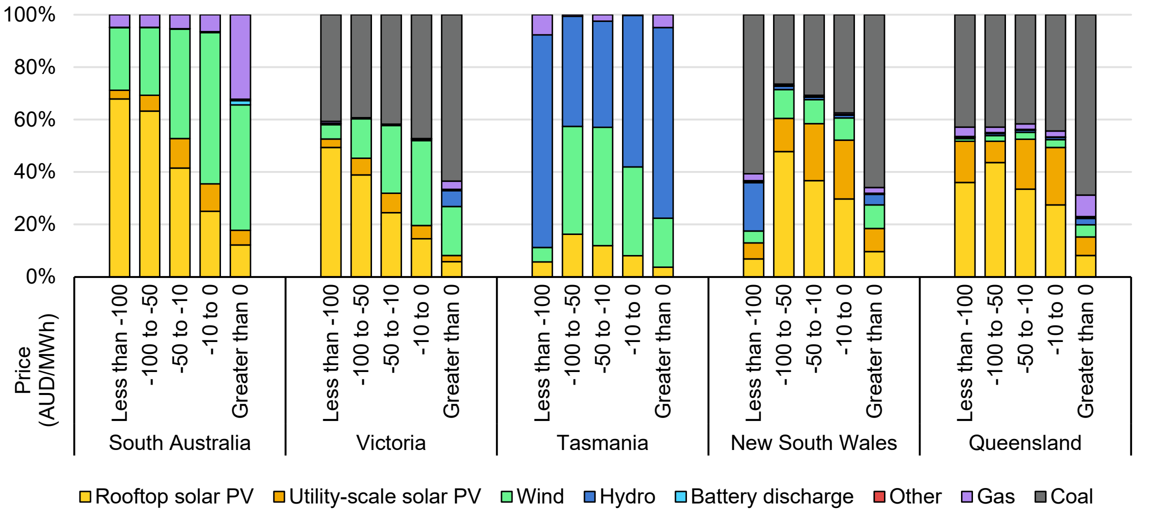
Most utility-scale VRE in the NEM operate during negative price periods initially but reduce output as prices drop further

For most of the utility-scale VRE generators, their bidding history suggests that they want to be dispatched for slightly negative prices (e.g. AUD -10/MWh), but not very negative prices (e.g. AUD -100/MWh). The observed behaviour and the price range is consistent with the hypothesis that these generators are treating their marginal cost as being slightly negative, in the ballpark of the green certificate price.

This can also be observed in the distribution of the negative prices. Most of the negative prices in the NEM are moderately negative, such that they are within the AUD -50/MWh to -10/MWh range. This is comparable to the spot prices for large-scale generation certificates (a type of green premium), which ranged between AUD 40-50/MWh over the analysis period. Nevertheless, in South Australia and Victoria, lower negative prices in the range of AUD -100/MWh to AUD -50/MWh are commonly observed, which are below the negative prices of these green certificates. These two states are also the only regions that are consistently seeing a large amount of prices below AUD -100/MWh, though these make up less than 5% of the negatively-priced hours.

Utility-scale VRE generators, especially wind, react to negative prices. Both in South Australia and Victoria the share of wind in total generation during negatively-priced hours is the highest for the AUD -10/MWh to AUD 0/MWh range, with 58% and 47%, respectively, but declines significantly when prices fall further. Utility-scale solar PV's share continues increasing until the AUD -100/MWh to AUD -10/MWh range, but then falls sharply beyond the AUD -100/MWh threshold. By contrast, the share of rooftop solar PV keeps increasing as the prices fall further, even beyond the AUD -100/MWh threshold. This trend is most notable in South Australia, where the share of rooftop solar PV in generation is close to 25%, the highest among NEM regions.

Average annual share of generation by fuel type during negative prices in NEM regions in Australia in 2024



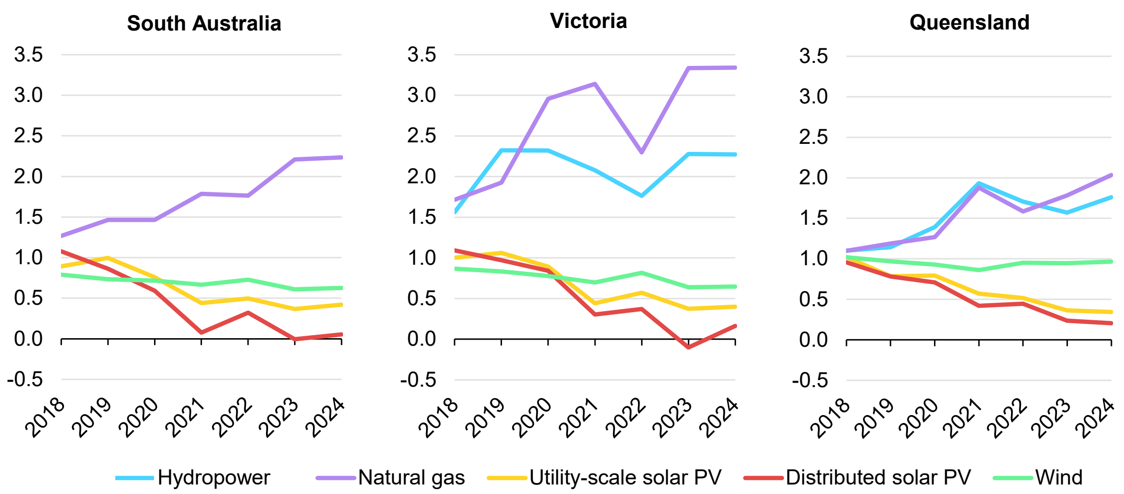
Notes: The x-axis refers to wholesale electricity price thresholds in AUD/MWh. The analysis excludes imported power. In the analysed time period, New South Wales, Queensland and Tasmania had fewer than six hours of prices lower than AUD -100/MWh, hence the fuel breakdown there for this price interval does not have much explanatory power. South Australia and Tasmania do not have coal-fired power plants.

Inflexible rooftop PV contributes to negative prices and lower solar capture rates, while batteries and tariff design can help

The total volume generated by rooftop solar PV during negative price periods is significant in some NEM regions. For instance, rooftop solar PV generated more MWh of energy during negative prices than during positive prices in South Australia (2 000 GWh vs. 1 200 GWh) and Victoria (3 160 GWh vs. 2 440 GWh) during 2024. In both these regions, electricity prices become more negative with the increasing proportion of electricity generated by rooftop solar. These systems, which are often under schemes with fixed prices, typically do not respond to price signals. Since rooftop solar is generally not curtailed based on price, the indirect impact on prices is equivalent to a generator which bids all volume at the lowest permissible price (AUD -1 000/MWh).

The trend of higher occurrences of negative prices during the daytime and the reduced system value of solar PV are very much related. While the capture rates of dispatchable plants in the NEM such as hydropower and natural gas-fired power have remained robust, those of solar PV have been declining. In particular, the capture rate of rooftop solar PV has dipped below zero on average in the fourth quarter of the years since 2022. This is driven by the fact that a very high share of annual rooftop solar PV generation (62% in South Australia, 56% in Victoria and 45% in Queensland) takes place during negatively priced periods. At the same time, more batteries are being deployed in the residential sector, with 56 000 household battery systems installed in 2023 compared to 43 000 in 2022. These systems, when combined with adequate (e.g. time-of-use or dynamic) residential electricity tariffs, can take advantage of low and negative prices to help raise the capture rate and system value of rooftop solar PV, while allowing consumers to reduce their bills.

Capture rate of generators by fuel type in selected NEM regions, 2018-2024



Notes: Capture rate is a measure of how well a generator (or set of generators) performed in terms of timing generation to align with high prices. Capture rate is the volume-weighted average price of a generator (or set of generators) divided by the (unweighted) average price of the region. Phrased differently, it is the total spot revenue for a generator(s) (AUD) divided by total volume (MWh) to get AUD/MWh, divided by unweighted average price (AUD/MWh). If a generator produced a constant power output for the whole time period, the capture rate would be 1. Peaking plants turn on for high-priced periods and off for low periods, so they tend to have capture rates above 1. A rate less than 1 suggests a generator is generating mostly during low prices. Dividing by the volume-weighted average price instead would give participation rate, which tells the same story. Rooftop solar is often behind the meter, treated as negative load. Capture rate here reflects the price the retailer was exposed to for export or reduced import. There is no hydropower in South Australia so it is not shown on that chart.

Interconnection enables export of negatively priced electricity that can lower prices in the importing region

Interconnections are important sources of system flexibility. In this context, an exporting market area with excess electricity and negative prices can help reduce prices in a neighbouring importing market, allowing it to benefit from cheap energy, and can also contribute to potentially lowering them to below zero. In Tasmania, for example, negative prices are predominantly driven by the export of negatively priced energy from Victoria to Tasmania, where producers in Victoria are effectively paying the consumers in Tasmania to buy their excess energy. In 2024, during more than 90% of the intervals when prices were negative in Tasmania, they were also negative in Victoria. In these instances when both regions have negative prices, Tasmania’s were higher (less negative) 70% of the time. Tasmania’s hydropower often generates during intervals of negative prices. However, hydropower exhibits different behaviours and strategies compared to VRE and thermal generation sources, particularly regarding out-of-market commitments. In the specific case of Tasmania, which is an island interconnected to the mainland only via the high voltage direct current (HVDC) Basslink to Victoria, hydropower needs to continue running to provide inertia to the island's power system.

For an exporting region, not being able to export excess electricity can prevent an importing region from benefitting from cheap energy while it can also exacerbate negative electricity prices in the exporting region. Interconnection constraints, for example, can sometimes magnify the effects of negative prices by limiting energy flows between regions. Key interconnectors, such as the Queensland-New South Wales Interconnector (QNI) and the Victoria-New South Wales Interconnector (VNI), frequently operate at capacity, preventing excess renewable energy from being exported to higher-priced regions. Addressing this issue is one of the reasons why an interconnector is being constructed between South Australia and New South Wales. These limitations are particularly acute during periods of high solar generation and low demand, reinforcing negative prices and reducing the ability to minimise costs across regions with different supply and demand conditions.

Growth in utility-scale storage is boosted by higher energy arbitrage potential with negative prices and favourable spreads

Negative prices incentivise investments in storage by creating favourable arbitrage opportunities. For example, in South Australia during Q4 2023, batteries generated more revenue by charging during negative price periods than they incurred in costs during positive price periods, with charging – typically a source of cost – becoming a source of income. The rapid decline in battery costs, combined with the rising energy arbitrage potential, is resulting in a strong boost in battery expansion. As of end of 2023, 5 GW/11 GWh of utility-scale batteries were under construction versus 1.4 GW/2 GWh by end-2022. Australia's first-ever tender for long-duration energy storage (LDES) took place in 2023 in New South Wales (NSW). The tender was awarded to Germany's RWE for its Limondale project, an eight-hour battery energy storage system. Later that year, an additional 4 GWh of LDES resources were awarded through another NSW tender. These included a large-scale advanced compressed air energy storage (A-CAES) project and several other eight-hour Li-ion BESS projects.

Despite acting as important price signals, negative prices alone may not suffice for increased system flexibility. As discussed in the IEA's Integrating Solar and Wind report, regulatory frameworks, market designs and adequate tariff structures are essential to promote flexible operation. Time-of-use tariffs and smart EV charging, alongside digitalisation and virtual power plants, can significantly improve demand-side flexibility. Additionally, resolving grid congestion and improving interconnections will unlock further flexibility.

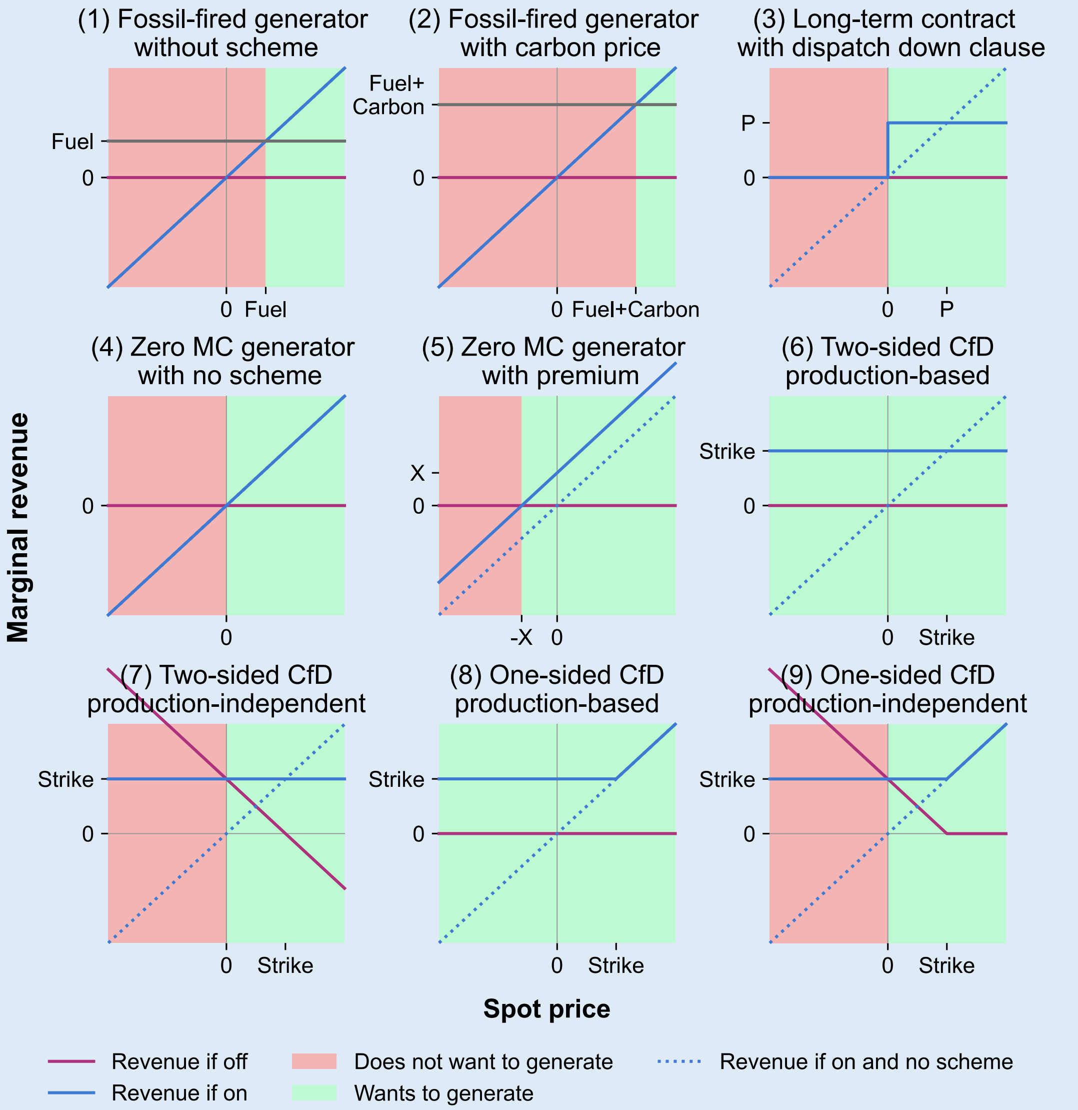
Understanding the effects of various schemes and contractual arrangements on bidding behaviour of generators on the wholesale electricity markets

Various mechanisms such as on-top payments (premiums), CfDs, and long-term contracts such as power purchase agreements (PPAs) are instrumental in increasing or stabilising revenue for projects, or mitigating market risks for developers. How these schemes and contracts are designed, and to what extent they allow short-term market price signals, can affect generators' bidding behaviour on the short-term wholesale electricity markets. Generators may be willing to bid negative prices and remain in the market even when the spot price (i.e. market clearing price) is negative if the corresponding schemes result in a positive marginal revenue. These types of contractual or regulatory inflexibilities can apply to different types of generators irrespective of their fuel type, such as VRE and thermal generators.

A schematical representation of various contractual and regulatory schemes and their potential effect on the market bids of the supply side is provided below, followed by a point-by-point explanation of each of the concepts. These reflect marginal costs and revenues as if generators did not face intertemporal constraints such as ramp rates and startup costs (i.e. as if the spot price was constant over many hours).

Demand side response can also be a major potential lever for increasing system flexibility. Investigating the effects of certain potential contractual arrangements and schemes on the demand side can be relevant, but our analysis here focuses only on the supply side and does not look at the wider market design aspects.

Marginal revenue curves for different schemes and contractual arrangements on the supply side of electricity markets, excluding intertemporal constraints



Notes: Carbon = cost from CO_2 price; CfD = Contract for Difference; Fuel = fuel price; MC = marginal cost; P = fixed long-term contract price; Strike = strike price of the CfD; X = revenue from the premium. For each graph, the horizontal axis represents the spot price (e.g. USD/MWh). The vertical axis represents the marginal revenue per unit of energy, after including the revenue/cost from the respective scheme. Plots are for zero-marginal-cost generators, unless otherwise specified. Generators want to generate in the green regions and turn off in the red regions, where their marginal revenue is higher if they turn off than their marginal revenue if they are on (ignoring intertemporal considerations, technical inflexibilities and electrical constraints). Policies which result in some green area left of the zero spot price (the vertical axis) can incentivise bidding negatively. The figures for fossil-fired generation exclude start-up and ramping costs; these can result in inflexibilities such that generators may be willing to accept negative prices and bid accordingly negatively to keep running instead of shutting down.

(1) Fossil-fired generation without any scheme: In contrast to wind and solar PV generation with negligible marginal costs, fossil fuel-based plants have a fuel cost. Without any scheme, and excluding start-up and ramping costs, they want to turn on when the marginal revenue (i.e. spot price) exceeds their marginal cost, which is above zero due to fuel costs. The plotted marginal revenue curve is not applicable to cases with intertemporal constraints. Operationally, technical inflexibilities such as limited ramping rates and minimum load levels, and the costs associated with shutting down and starting amid intertemporal portfolio effects, can influence the bidding behaviour of thermal generators. Similarly, certain out-of-market commitments and obligations can play a role whether a power plant needs to run or not. These can result in thermal generators to bid negatively to keep running instead of shutting down.

(2) Fossil-fired generation with CO_2 price: A carbon price shifts a fossil-fired generator's fuel cost higher. This increases the marginal cost the generator would bid and the minimum spot price they need to be infra-marginal. The previous discussion regarding technical inflexibilities of thermal generators is also valid in this case.

(3) Long-term contract with dispatch down clause: Long-term contracts such as PPAs can apply to different sources of generation assets in electricity markets, including both VRE and thermal generators. PPAs that require a minimum level of production, or pay-as-produced types of PPAs generally where the revenue the generator receives is based on its actual energy production, can incentivise producing during negative prices. This, however, depends on how the PPA is structured. For example, PPAs that have "dispatch down/curtailment" clauses can allow for economic curtailment when the price drops below a threshold (e.g. USD 0/MWh or below certain premiums such as the value of green certificates).

(4) Generators with zero marginal costs and no scheme: In this case, marginal revenue of the generator equals the spot price. For example, wind and solar PV power generation have no fuel cost, so they turn on whenever marginal revenue is positive. If the spot price falls below zero, the generator stops producing (assuming they are technically able to) since they would be losing money.

(5) Generators with certain top-up revenues or premiums: A certificate of origin, a feed-in-premium or any other type of top-up payment of USD X/MWh effectively adds revenue on top of the spot price. Generators receiving such revenues will be willing to bid prices down into the negative region, as long as it is at least USD -X/MWh, because they 'see' a price higher than the spot price. For example, if a generator expects to be able to sell their green certificates for USD 10/MWh they will be willing to pay to generate power (and thus certificates) at negative spot prices, until USD -10/MWh.

(6) Two-sided production-based CfDs: The CfDs are contracts between a generator and a counterparty, typically a government-owned entity, that aim to hedge price risk and provide price stability. CfDs are based on the difference between the market price and an agreed strike price for electricity. In a two-sided CfD, if the strike price is below the spot price, the generator is paid the difference by the government and effectively receives the strike price. If the spot price exceeds the strike price, then the generator pays the government back, again, effectively receiving the strike price.

If the CfD is based on the sent-out volume of each specific generator, and the generator shuts down to avoid paying to generate during negative prices, the volume used to calculate the CfD is reduced, and therefore the generator will be worse off. Thus, a CfD based on sent-out volume penalises generators for turning off during negative prices, leaving a net incentive to produce at all price levels. Some forms of two-sided CfDs have two separate strike prices to cap losses/gains during extremes whilst maintaining spot exposure in the middle. If the lower strike price is non-negative, then the disincentive to curtail during negative prices remains.

In several countries with production-based CfDs, additional clauses have been introduced to halt support payments after a specific number of consecutive hours with negative prices. These measures aim to encourage system-friendly operation of generators during such periods, though they do so by exposing them to some degree of downside price risk.

(7) Two-sided production-independent CfDs: In contrast to CfDs with sent out volumes, production-independent CfDs can be signed for a fixed quantity (a certain number of TWh over each year), or could be defined based on a reference asset or a baseline. Since the CfD calculation is decoupled from the actual output, generators are still hedged against low prices but can save money on the spot market by turning off when the price is negative. Various stakeholders have proposed different forms of production-independent CfDs, such as the "capability-based CfD", the "yardstick CfD", and the "financial CfD". By decoupling payments from the actual production of the plant, these schemes can incentivise dispatch, asset siting and outage planning to be more system-friendly. However, these types of mechanisms are more complex to design as well as implement and may expose investors to varying levels of downside risk depending on the scheme.

(8) One-sided production-based CfDs: In a one-sided CfD scheme, if market prices are below the strike price, the government compensates the generator by variable top-up payments based on the difference between market prices and the strike price. Different than in a two-sided CfD, if the spot price exceeds the strike price, the generator can keep the excess revenues. Similar to in a two-sided production-based CfD, the incentive to generate during negative spot prices remains.

(9) One-sided production-independent CfDs: In the case of a one-sided CfDs signed for a fixed or reference quantity, the CfD calculation is decoupled from the actual generator output. As previously explained in the two-sided case, the generator can save money on the spot market by turning off when the price is negative.

Managing upward pressure on grid tariffs is essential for an affordable energy transition

While the energy transition is set to reduce the overall cost of generating electricity, grid tariffs are expected to rise due to expanding electrification and further integration of renewables. This increase in grid tariffs stems from the need to raise investments in infrastructure expansions and upgrades to serve growing conventional electricity demand and to accommodate new electricity consumption from EVs and heat pumps, even though the higher costs are shared across a broader end-user base. Utilities must also invest in grid digitalisation, energy storage and smart technologies to manage the grid efficiently. Additionally, the need to maintain grid stability and reliability while phasing out traditional power plants requires substantial investments in flexible resources and grid reinforcement, ultimately leading to higher network charges for consumers despite lower generation costs.

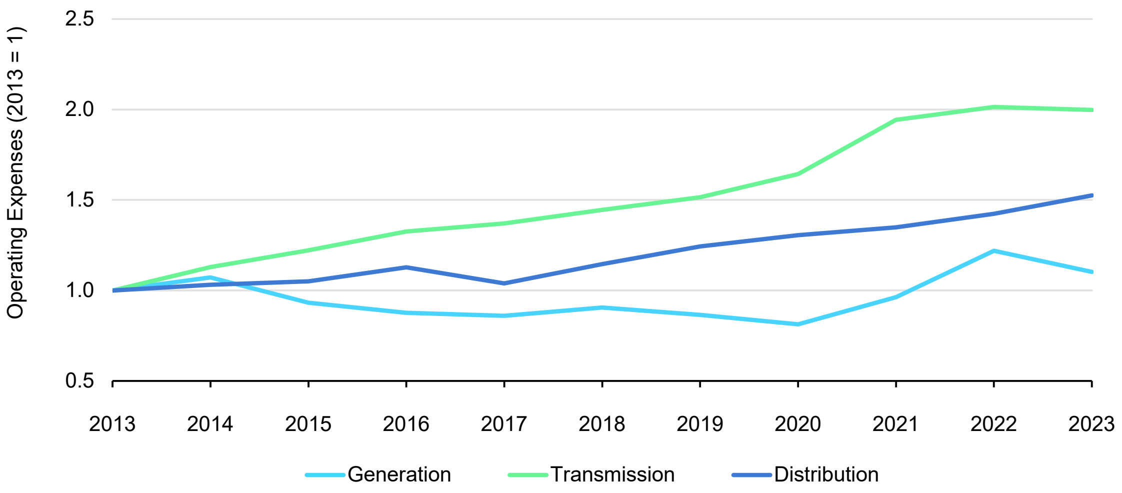
With grid tariffs anticipated to rise, heightened scrutiny by end-users will likely prompt deeper examination of the reasons for this increase. In most countries, grid tariffs are set by regulators based on a tariff determination method and an understanding of the cost composition. However, there are a wide array of underlying factors boosting grid tariffs, which vary by region, consumer segment and power industry structure. This highlights the need for transparent definitions of cost components to enable regulators and other relevant stakeholders to track and compare tariffs across the regions and facilitate better decision making when developing ways to manage the costs.

The grid component of electricity tariffs has already been rising in some regions

Various countries around the world are seeing increasing electricity tariffs[23], and these will only rise further as the higher costs of building and maintaining grid infrastructure add upward pressure. In regions like the United States grid costs already show a relatively high growth rate. Since 2013, the cost of generating electricity in the United States has been relatively stable, whereas the cost of operating and investing in transmission and distribution infrastructure has grown by factors of 2 and 1.5, respectively. Similarly, in Italy, Spain and France grid tariffs for residential consumers have increased by approximately 60% since 2017, whereas in Hungary, Bulgaria and Poland industrial they have seen a broader range of 30% to 60% over the same period.

[23] Electricity tariffs refer to the kWh price paid by consumers. In regions such as Europe, where there is retail competition, it is more commonly known as the retail electricity price.

Operating Expenses of Major US Investor-Owned Utilities, 2013-2023



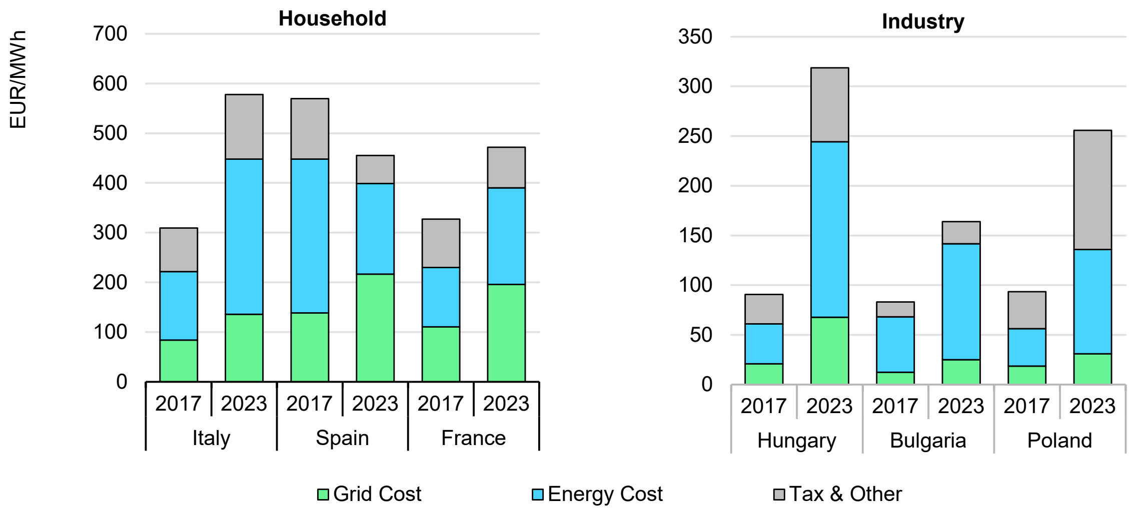
IEA. CC BY 4.0.

Source: U.S. Energy Information Administration (2023). Electric Power Annual.

While rising grid costs can push overall electricity tariffs up, the way they are distributed across consumer segments differs across countries. In some cases, the government directly influences the way grid costs are allocated to consumers, depending on the priorities of each country. In Germany and the Netherlands, industrial consumers receive sizeable discounts of up to 90% and 65%, respectively, to improve their competitiveness. A crucial difference is that German industries only receive the discount if they consume electricity at a constant rate, whereas Dutch industries receive it if they adjust their usage based on system needs, helping to reduce overall costs.

In China, industrial and commercial consumers are bearing a larger share of grid costs in order to reduce electricity tariffs for households and farmers. Alternatively, in countries with vertically-integrated utilities, governments set electricity tariffs at predetermined levels, such as in Korea, South Africa and Saudi Arabia. When they are not cost-reflective, it pushes grid cost increases onto the balance sheets of the state or state-owned utilities, which can lead to potential delays in grid investments or reduced levels of maintenance.

Household and industrial electricity tariff components in selected EU countries, 2017-2023



Notes: These countries were selected for their relatively high rates of grid cost increases. Industry refers to the average of industrial consumption levels.
Sources: Eurostat (2024) Electricity tariffs for household consumers; Eurostat (2024) Electricity tariffs for non-household consumers.

Balancing needs and congestion costs emerge as additional sources of grid tariff increases

Grid tariffs cover costs for infrastructure investment, operation, maintenance and sometimes subsidies, but these components lack international standardisation, complicating comparisons. Infrastructure investment is the main cause of higher tariffs, though countries differ in qualifying investments like battery energy storage systems (BESS) as recoverable through tariffs. Operational costs are rising sharply in some areas due to system balancing and congestion management, while some jurisdictions add charges to grid tariffs to socialise certain costs. These variations in cost categorisation across different countries complicate comparative analysis and strategic decision-making in addressing rising grid infrastructure expenses.

Grid investments provide upward pressure on grid tariffs

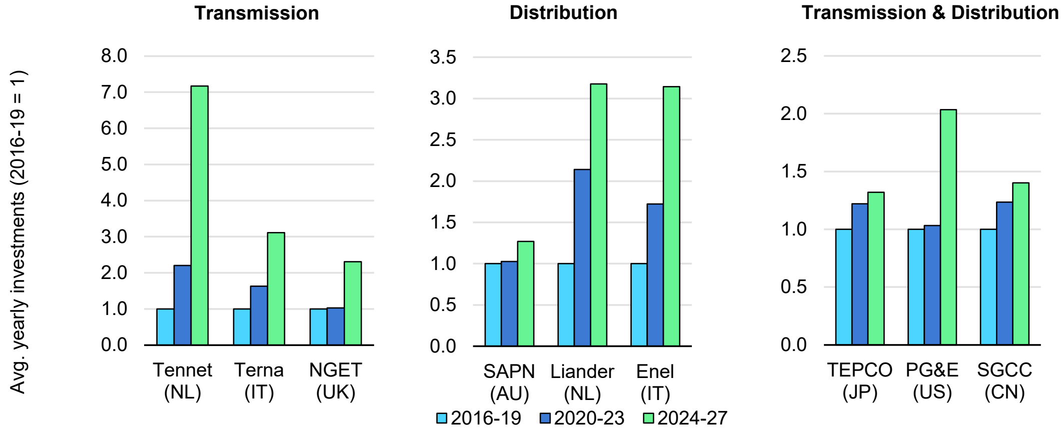
The main cost driver of grid infrastructure is, and will continue to be, the investments in new transformers, power lines and pylons, with significant expansion is expected both in advanced economies and emerging markets and developing economies (EMDEs). This expansion is needed to meet demand growth as well as to modernise ageing infrastructure and enhance its resilience. Modernisation is characterised by the deployment of digital, smart and flexible assets.

IEA analysis shows that transmission and distribution grids will need to increase by more than 20% in length by 2030 to meet energy and climate pledges in time and in full, requiring annual average investment in grids to rise to USD 600 billion from around USD 300 billion today. Investment in digital and smart grids, typically considered grid infrastructure, will also continue to grow.

Countries around the world are ramping up investments in grid infrastructure, though the underlying drivers vary based on local conditions and priorities. In many cases, expanding grids, upgrading ageing infrastructure, and integrating new demand are key factors behind rising expenditures. For example, Italy's Terna and Enel plan to allocate 67% and 55% of their respective capital expenditure for 2024-2028 and 2025-2027 to developing and upgrading assets and facilitating new connections, with Terna also investing over 10% of their capital expenditure in grid digitalisation. In the Netherlands, TenneT is set to increase its annual capital expenditures in offshore infrastructure from under EUR 500 million in 2022 to over EUR 5 billion by 2026, while distribution operator Liander is investing EUR 3.6 billion to overcome grid bottlenecks and integrating demand from electric vehicles and heat pumps between 2024 and 2026. TEPCO in Japan is preparing for rising demand from data centres and semiconductor manufacturers, with planned grid expenditures reaching USD 3.2 billion by 2027, and National Grid UK is dedicating 20% of its 2027-2031 investments, at GBP 6.6 billion, to improving grid resilience. By contrast, South Australia Power Networks (SAPN) is focusing on replacing and reinforcing existing infrastructure, allocating more than 57% of its 2025-2030 budget to asset replacement and network augmentation.

Several of the countries mentioned above have already projected the impact of planned investments on bills and tariffs. Regulators play a crucial role in determining how these investments are incorporated into grid tariffs, which are typically recovered based on approved expenditures and a cost recovery rate. In the Netherlands, TenneT forecasts an average annual increase in transmission tariffs between 4.3% and 4.7% from 2025 to 2034, depending on capital costs and whether external funding is available for grid investments, with offshore development constituting the largest factor. National Grid also forecasts an increase in the transmission costs element in electricity bills, from approximately GBP 23 per year in 2026 to GBP 44 in 2031 for average households. While transmission costs are expected to rise, they help achieve GBP 12 billion in savings from reduced system costs, primarily by decreasing congestion management costs, benefiting consumers with an average annual saving of GBP 40 per year. This largely offsets the increase from higher transmission costs. In South Australia, SAPN expects a slight decrease for residential and business consumers, with monthly bills dropping from AUD 613 to AUD 570 for residential customers and from AUD 1 466 to AUD 1 362 for businesses between 2024-2025 and 2029-2030. This is primarily due to assets constructed before 2010 being fully depreciated and the anticipated removal of the feed-in-tariff scheme in 2028.

Investments in grid infrastructure by selected companies, 2016-2027



Notes: NEGT is National Grid Electricity Transmission, SAPN is South Australia Power Networks, TEPCO is Tokyo Electric Power Company, PG&E is Pacific Gas & Electric Company and SGCC is State Grid Corporation of China. Data for Liander are up to 2026 and for SGCC up to 2025.

Source: IEA analysis based on S&P Global Market Intelligence (2025); TenneT (2024), Investeringsplan Net op Land 2024-2033; Tennet (2024), Investeringsplan Net op zee 2024-2033; Terna (2024), Industrial Plan 2024-2028; National Grid (2024), RIIO-T3 Business Plan; SA Power Networks (2024), 2025-30 Revised Regulatory Proposal; Liander (2024), Investeringsplan 2024 Elektriciteit en Gas; Enel (2024), Strategic Plan 2025-2027; Nikkei Asia (2024), Japan's TEPCO to invest $3.2bn in power grid to meet AI demand; PG&E (2024), Third Quarter Earnings 2024; GMK Center (2025), China's state grid operator plans USD 89 billion in investments for 2025.

The deployment of batteries is an emerging opportunity in many markets, as their costs continue to decline rapidly. While the main force behind the anticipated growth of BESS is the increasing need for flexibility, utilities are in some cases remunerating them through grid tariffs for their broader system benefits like voltage and frequency regulation. In some publicly-owned utility markets like Thailand and Namibia, BESS are treated as utility assets with costs partially recovered through tariffs, however, in liberalised markets, regulatory constraints typically prevent grid operators from owning assets that produce electricity. In these cases, countries such as India and Germany have used innovative financing mechanisms to remunerate BESS providers for grid services, creating predictable revenue streams while also tapping into their benefits for grid reliability and flexibility.

Rising operational costs contribute to grid tariff increases

While traditionally the main source of operational costs have been grid losses, maintenance and staff costs, congestion management and balancing costs are emerging as significant drivers too in some markets. In our analysis, we see this taking place in markets across the United States, Germany, the Netherlands, Spain and Great Britain. Congestion management costs can be relieved by more grid investment, which in turn raises grid costs and the grid cost component of the retail tariffs. A key question is how these changes will impact electricity prices for customers in the future. Yet, differences in reporting requirements as well as diverging grid management responsibilities and practices makes this difficult and highlights the importance of benchmarking and standardisation, which can help to enable international comparison and best practice sharing.

Balancing costs

Given the difficulty of precisely forecasting generation and consumption levels, there is often a mismatch between the amount of electricity generated and the actual demand at any given moment and node of the grid. Balancing costs arise from the need to correct these mismatches, mainly through market mechanisms where TSOs restore energy imbalances, such as dispatching generators and consumers increasing or decreasing generation and consumption during periods of oversupply or undersupply; and system imbalances by managing real-time supply-demand balances, frequency regulation and ensuring sufficient inertia. Locational mismatches in supply and generation may trigger the need for corrective action such as easing congestions and maintaining adequate voltages. The costs incurred during these operations are typically passed on to suppliers, and eventually to end users either in the energy and supply component or in the grid costs component of their electricity bill.

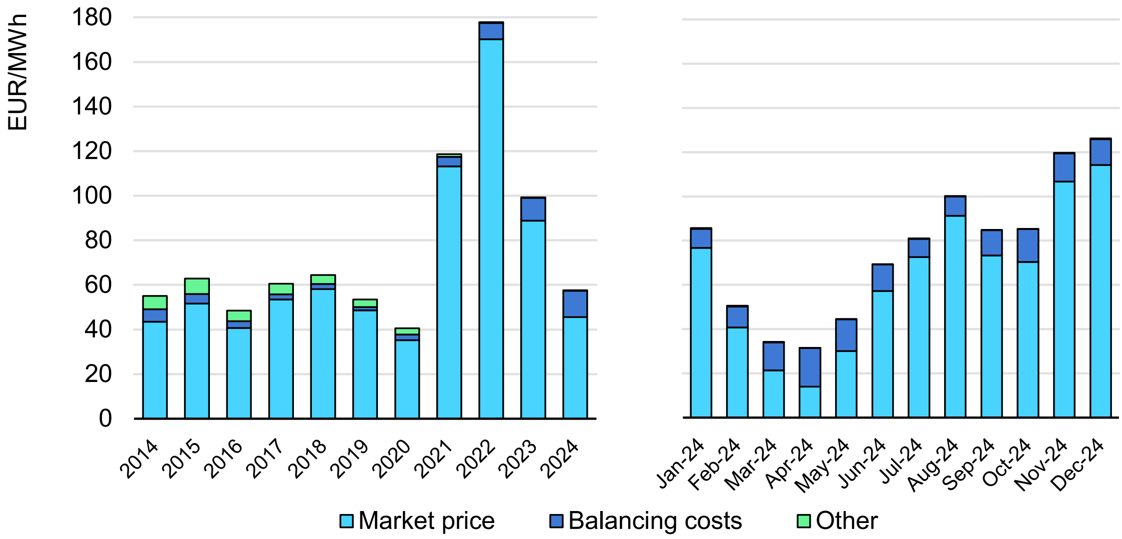
Countries with lower interconnection capacity or higher grid congestion have observed a significant increase in balancing costs, despite strategies to tackle cost by system operators. In the **United Kingdom**, the cost of balancing services use of systems (BSUoS) is mainly driven by constraint charges, and the fixed tariff to consumers was stable between GBP 2-3/MWh until 2019. It then rose to GBP 14/MWh for UK consumers between October 2023 and March 2024. Since then wholesale market prices have fallen, with the tariff now set at GBP 12.2/MWh between October 2024 and March 2025. However, National Energy System Operator (NESO) forecasts continued increases in the long-term.

Balancing costs in the **US PJM** market (Pennsylvania-Jersey-Maryland) are closely linked to wholesale market price trends and are generally comparably lower than in the examples mentioned above. Lower cost levels are influenced by a higher share of dispatchable generation given the relatively low integration level of VRE, with solar PV and wind power accounting for less than 7% of the generation mix in 2024. Between 2017 and 2022, the cost of balancing reflected in consumer electricity prices increased significantly, rising from USD 1-2/MWh in 2017 to USD 4-10/MWh in 2022. However, in 2023 and 2024, balancing costs moderated, returning to a range of USD 2-3/MWh.

In European liberalised electricity markets, it is common for balance responsible parties (BRPs), such as power producers, suppliers or large consumers, to balance their own portfolio, while the TSOs generally takes care of the residual balancing. For example, in **Germany**, while balancing energy costs are borne by the BRPs, the associated balancing capacity costs are included in consumer electricity bills, though they are neither fixed nor transparently itemised as a separate charge.

In **Spain**, balancing costs are included in the wholesale electricity price component and their share has been increasing in recent years. Since there is no fixed tariff for balancing costs in retail electricity tariffs and wholesale market prices now account for a decreasing proportion of the energy and supply component, various suppliers and consumers face growing uncertainty regarding this component.[24] Between 2019 and 2024, the balancing component paid by Spanish consumers has increased eightfold, from EUR 1.5/MWh to EUR 11.9/MWh. Despite the fluctuations in wholesale market prices, the share of balancing costs within the full wholesale market price rose significantly, from 3% in 2019 to 10% in 2023, and increased further to 21% in 2024. While low-carbon generation sources, especially solar and wind, significantly helped push market prices down, balancing costs remained substantial.

Electricity wholesale market price and added costs in Spain, 2014-2024



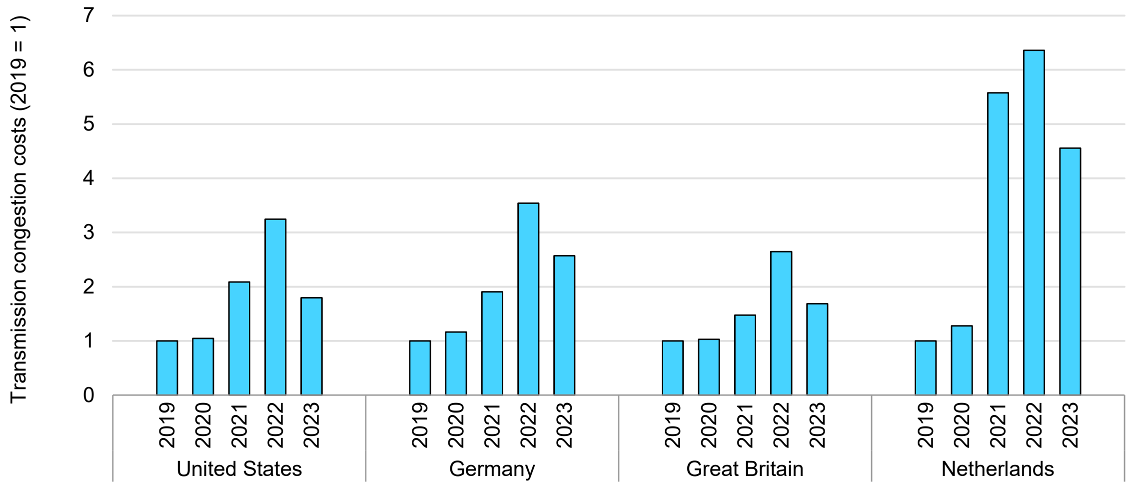
Note: Other includes capacity payments and demand response programmes, both of which have been affected by regulatory changes.
Source: IEA analysis based on data from Red Eléctrica.

[24] Large energy consumers in Spain are not exempted from these charges unlike in Germany.

Congestion management costs

Congestion management costs can contribute to electricity tariff increases. In countries like Germany, the United States and Great Britain, where congestion costs are recovered through grid tariffs, they tripled between 2019 and 2022. The increase was sixfold in the same period in the Netherlands. In 2023 congestion costs went down due to lower natural gas prices, even though congestion volumes remained high in both Germany and Great Britain. Over the same period, the United States saw reduced congestion volumes and costs due to lower gas prices and less extreme weather events. Yet, long-term concerns remain because of expected demand increases and renewables growth, combined with delayed build-out of grid infrastructure, spurring debate over cost distribution and mitigation strategies.

Transmission grid congestion costs estimates for selected markets, 2019-2023



Sources: IEA analysis based on Grid Strategies (2024), 2023 Transmission Congestion Report; Bundesnetzagentur (2024), Monitoringbericht 2024; National Energy System Operator (2024), Daily Balancing Services Use of System (BSUoS) Cost Data; Tennet (2024), Annual Market Update 2023.

Congestion management costs are handled differently among countries and are reflected in grid tariffs in various ways. In Great Britain, these costs are incurred through the balancing mechanism, where congestion is managed alongside balancing services via a market-based approach. While the costs are averaged across all producers and consumers through the grid tariff, there is a locational element within the transmission tariffs that aims to contribute to effective congestion management. In Germany, by contrast, congestion costs arise from re-dispatching conventional power plants and curtailing renewables to prevent grid overload. These costs are settled outside the market, with grid operators paying generators to adjust their output, and then they are passed on to consumers through grid tariffs. In the Netherlands, controllable generation is subject to redispatch while the demand side can also participate by making an agreement to increase or decrease consumption during anticipated or actual congestion periods against a compensation. In parts of the United States, congestion costs are directly tied to location and are reflected in electricity tariffs through locational marginal pricing. Here, the consumer causing the congestion pays higher prices, as congestion costs are embedded in price differences between where electricity is generated and consumed. However, part of congestion revenues in the United States are distributed back to consumers through credits or tariff adjustments, partially offsetting congestion costs.

Countries are implementing various measures to keep congestion management costs at reasonable levels. In Great Britain, introducing locational pricing is highlighted as a key strategy in market design discussions, as it could better reflect where congestion occurs and incentivise more efficient use of the grid. In Germany, the government introduced a new regulation in April 2024 called Use instead of curtail, (Energy Industry Act - EnWG), aimed at reducing congestion by offering cheaper electricity to industrial consumers in areas with high electricity production and grid bottlenecks. This measure is currently in a test phase until September 2026, with potential adjustments based on the outcomes. In the United States, regulators are exploring ways to allocate congestion revenue more effectively. Proposed changes include directing a larger share of congestion revenue back to consumers through reduced rates or credits and increasing the transparency of how these revenues are collected and distributed, allowing consumers to better understand their role in congestion costs.

Additional charges in grid tariffs reflect broader infrastructure and policy costs

In some countries grid tariffs contain additional charges as a way to socialise the costs to mitigate risks from the broader environment or to compensate specific segments of society for hardship due to the development of the electricity system. These kind of components are not uniform because it depends on the risk profile of the country.

Across the world there is a large variety of other tariff components that are added to grid tariffs to compensate for certain reliability functions. For example, in California the state regulator approved wildfire mitigation expenditures for utility companies on a yearly basis, part of which are collected through the grid component. These have been rising rapidly, with the largest increase seen at PG&E after it spent USD 74 million in 2019 on wildfire and catastrophic events mitigation measures, which rose to USD 2.65 billion in 2022, equal to 18.5% of the utility's total revenue requirement. Even though this level of expenditure is not expected on a structural basis, it still pushes electricity tariffs up significantly.

In Japan, the grid tariff contains two additional charges to cover costs of their nuclear fleet. These charges were introduced in April 2020 to ensure financial responsibility in managing nuclear energy. They are collected through electricity tariffs to support decommissioning efforts and provide necessary compensation to affected individuals. The decommissioning facilitation charge covers costs for safely decommissioning nuclear power plants, while a compensation charge funds reparations for victims of nuclear accidents.

Reliability: Extreme weather events make improved security imperative

The new era of electricity has heightened the need for secure and resilient power systems

As power systems continue to expand with continued electrification and both the demand and the supply of electricity becomes more weather-dependent, ensuring the security and reliability of electricity supply is imperative. Many power systems around the world face adequacy issues during periods of elevated electricity demand, such as during peak seasonal heating needs in winter and cooling in summer. Extreme weather due to winter storms or intense heatwaves, especially when compounded with impacts on the supply side such as droughts, fuel supply disruptions or power plant outages, can put significant strain on the power system. This chapter provides an overview of our monitoring efforts of global developments in electricity security and reliability. We compare and analyse recent weather-related disruptions, discuss their impacts and highlight measures to remedy them.

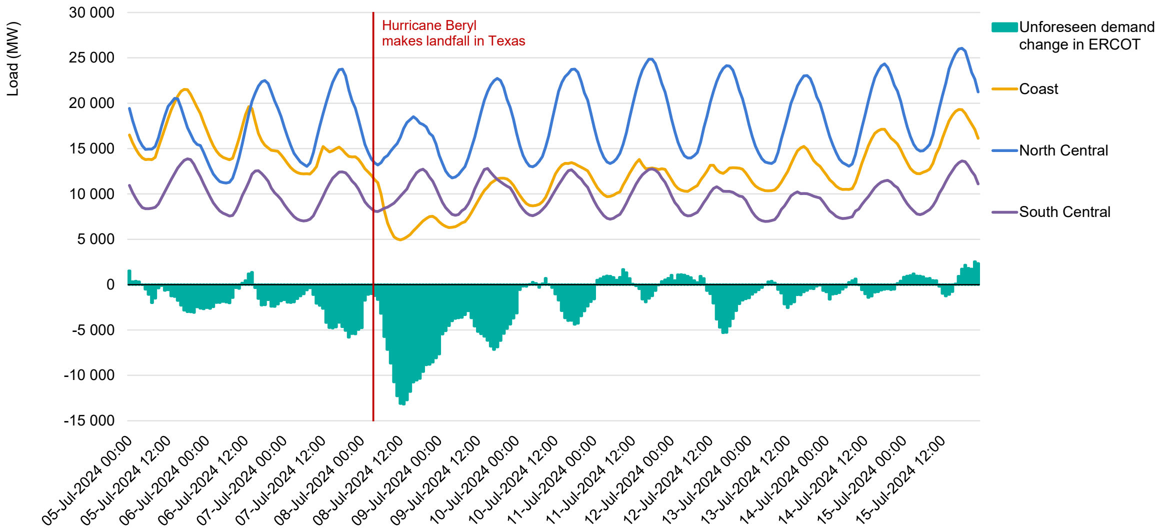
In a following section, resource adequacy assessments across different regions are discussed in light of the increasing impact of weather on power systems. We emphasise the need to incorporate the stochastic nature of weather impacts and the evolving changes on the generation and demand side into these assessments. Our analysis of recent adequacy-related power shortages illustrate that there is a range of measures that can be implemented. Improvements in adequacy assessment methods, adoption of more refined and multiple metrics in adequacy studies and more universal reliability standards could all help more effectively manage simultaneous and widespread impacts on power generation, grids and supply. This will become increasingly important with risks from extreme weather events expected to increase going forward (see below, *Planning for resource adequacy: Emerging risks and trends in assessment methods*).

2024 recorded major power outages across regions amid weather, fuel and grid issues

Extreme weather and natural disasters caused large-scale power outages in many regions. Extreme weather events such as storms, droughts and heatwaves led to widespread power disruptions in 2024. Large-scale power supply interruptions plagued a broad swath of countries and regions, highlighting the need to increase resiliency against the growing weather impact on power systems.

In the **United States**, major weather-related power outages in 2024 started in mid-January, as a massive winter storm left more than 800 000 residential and commercial clients in 12 states without power across the eastern half of the United States. The storm later moved towards the Midwest and Pacific Northwest, where 350 000 customers were affected. Hurricanes were particularly frequent in the Atlantic this year, as predicted by the NOAA in May, causing widespread damage to electric infrastructure despite utilities preparing for the season. Hurricane Beryl left nearly 3 million customers without power in Texas on 8 July 2024, 88 000 of which had not received power more than a week after the event amid a dangerous heatwave. As a result of the power outages, the electricity load in the ERCOT system, the independent system operator (ISO) that delivers approximately 90% of the electricity used in Texas, was reduced much more sharply than forecast, particularly in the Coast subregion, which encompasses major cities like Houston and Galveston, and the coastal region. The unforeseen change in demand reached -13.2 GW at 1 pm on 8 July, and it remained volatile for several days. The cost to repair Beryl's damage to CenterPoint's electric infrastructure in the Houston area was estimated at between USD 1.2-1.3 billion, leading to an expected increase in retail tariffs. The hurricane also decimated **Jamaica**, **Martinique**, **Tobago** and **other Caribbean islands** in early July. In **Jamaica**, more than 60% of electricity customers in the island were affected by power outages, which in some cases lasted over a month.

Electricity load in selected ERCOT subregions in Texas (US) during Hurricane Beryl, 5-15 July 2024



Notes: ERCOT = Electric Reliability Council of Texas. East, Far West, North, South and West subregions are excluded from the chart.
Source: IEA analysis based on data from Energy Information Administration (EIA) (2024).

In August, Hurricane Debby caused power outages for more than 300 000 electricity customers in Florida and Georgia, before moving up the coast as a tropical storm and causing further damage in Ohio, Pennsylvania, New York and Vermont. In late September, Hurricane Helene, the deadliest hurricane to hit the US mainland since hurricane Katrina in 2005, left nearly 6 million customers in ten states without power. According to Georgia Transmission, over 100 high-voltage transmission lines and more than 60 associated electrical substations went out of service in the state. Several nuclear plants in Alabama, South Carolina and Georgia were near the storm's path and, even though none of them sustained any significant damage, operations had to be adjusted to maintain grid stability. Just two weeks after that, in October, Hurricane Milton caused power outages for 3.4 million homes and businesses in Florida. Over 50 000 utility workers from different states and Canada were deployed to repair the damage on electric infrastructure. In mid-November, a bomb cyclone brought strong winds and heavy snow across the Pacific Northwest and left more than 700 000 customers without power.

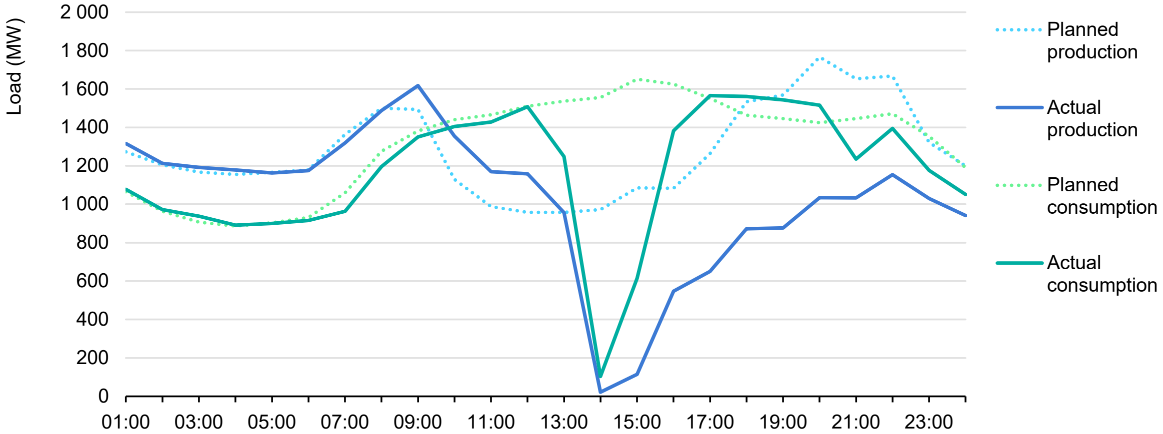
In **Australia**, a storm resulted in the physical collapse of six transmission towers in Victoria on 13 February, leading to 2.7 GW of generation being disconnected from the grid. More than 530 000 customers were off power across the state. Victoria's energy minister referred to this event as unprecedented in terms of impact of extreme weather on Victoria's power grid. Load shedding in excess of 300 MW was ordered by AEMO just after the event. In a preliminary operating incident report, AEMO stated that "the voltage depression during the fault was experienced throughout Victoria and was observed to be as low as 0.63 per unit (p.u.)". Tasmania also suffered the consequences of this event via the Basslink interconnector, recording a minimum frequency of 49.35 Hz.

In **Brazil**, Sao Paulo suffered a blackout on 11 October, where around 2.6 million clients lost power due to a 30-minute storm spike. The storm damaged 17 high-voltage lines, along with 11 substations. In the aftermath of the blackout, the recovery effort by Enel has been slower than expected by the local administration. One day after the event, more than 1.4 million homes were still without electricity, and by 14 October, around 530 000 homes were yet to have their power restored. In response, Brazil's Electricity Agency (Aneel) ordered Enel to provide the details of the event and raised the possibility of recommending the end of the Italian company's concession. Aneel considered that Enel had recurrent below-optimal recovery responses in recent times after major blackout events in the Sao Paulo region, particularly after the storm in November 2023. For both events, the major causes of the power outages were trees falling on medium-and low-voltage systems, highlighting the need for the maintenance of the grid and surrounding elements.

Ecuador declared a state of emergency for the electricity sector in April, as El Niño and the worst drought in decades resulted in critically low water levels in reservoirs that provide 75% of its electricity generation. The halt on imports from Colombia, which was severely affected by the drought as well, additionally contributed to electricity scarcity in the country. Nationwide power cuts were implemented for up to eight hours a day, and the government suspended working days on 18 and 19 April. Although rationing was suspended in May, the persistent drought resulted in another state of emergency in August and stricter power cuts, up to 14 hours a day in November, despite incorporating a 100 MW floating power plant into its power system. The industry sector estimates a loss of USD 12 million per hour of outage at the national level. By mid-November Colombia resumed electricity exports to Ecuador, following several weeks of significant rainfall and improved forecasts for upcoming months.

Albania, **Montenegro, Bosnia and Herzegovina** and **Croatia** were largely affected by a voltage collapse followed by a total blackout in the area on 21 June, amid a major heatwave. The blackout was caused by insufficient clearance with vegetation, as confirmed by the European Network of Transmission System Operators for Electricity (ENTSO-E) in November, at a moment of higher power demand due to the increased need for climatisation. Two high-voltage lines tripped due to line to ground faults, first in Montenegro and then in the Albania-Greece border. According to ENTSO-E, following this second trip, the voltage in the South-Eastern part of the Continental Europe power system started to decrease rapidly and led to several lines disconnecting one after the other causing a system separation, and then a voltage collapse in the area.

Electricity production and consumption in Bosnia and Herzegovina, 21 June 2024



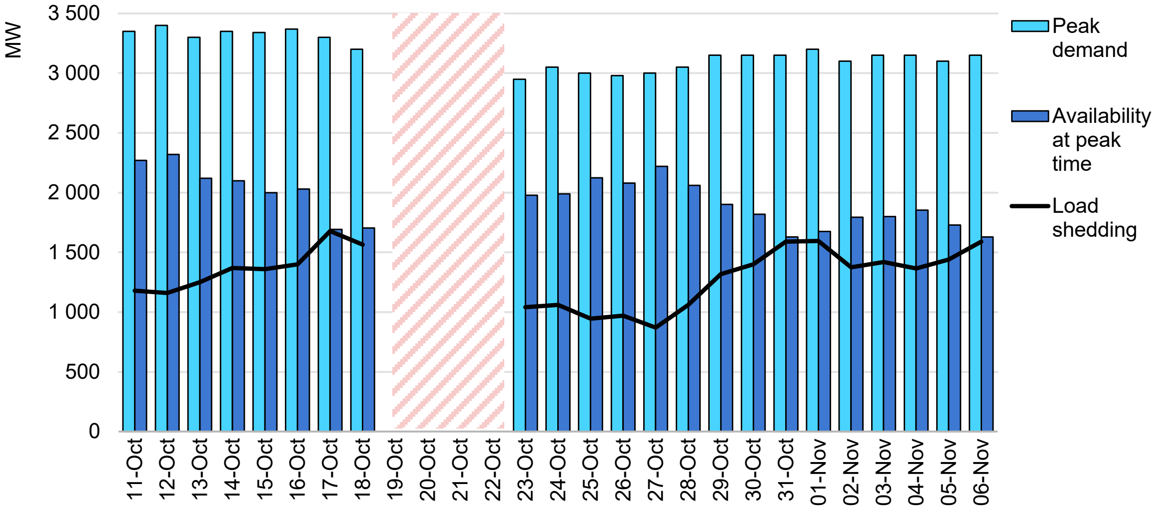
Source: IEA analysis based on data from Independent System Operator in Bosnia and Herzegovina (NOSBiH) (2024).

Power outages and blackouts resulted from fuel shortages due to supply disruptions in several countries

After years of frequent shortages and outages, **Lebanon** suffered a nationwide electricity blackout on 17 August 2024, as Electricité du Liban (EDL) was forced to shut down its last operational unit at the Zahrani thermal power plant due to the complete depletion of fuel oil reserves. EDL had warned about this scenario 10 days earlier, and other operational units had already been shut down in July due to lack of fuel, but the government did not make overdue payments to their Iraqi counterparts and the contracted oil volumes were not delivered. The outage affected essential services such as sewage systems, airport, port and water pumps, leading authorities to urge the population to limit water consumption. After two days, 80 MW from the Litani hydropower plant and an additional 80 MW from a small unit in the fuel-powered Zahrani plant were operational and supplied electricity to essential infrastructure only. The country was in the dark for nine days until an Egyptian tanker supplied the necessary fuel to generate 350-400 MW between Deir Ammar in northern Lebanon and Zahrani in the south, enough to supply electricity to EDL clients for 3-4 hours per day, roughly pre-blackout production levels.

In **Cuba**, a country which relies on oil-fired power generation for more than 80% of its electricity mix, the passage of several hurricanes through the Caribbean in October hindered the delivery of fuels, which in addition to heavy maintenance issues caused the 330 MW Guiteras power plant to go offline on 18 October, leading to a blackout for the whole island. Consequently, the government declared a national emergency and suspended all non-essential activities. To synchronise each of the thermal units, seven isolated subsystems powered by fuel oil or diesel-fired distributed generators were implemented, which supplied the necessary energy for a restart of the thermal plants. In the following two days, power was partially restored in the western part of the island, until another complete blackout occurred on 20 October. Power was again restored to around 70% of customers with more than 1 400 MW of demand met two days later, and as of 24 October, Cuba’s Electric Union (UNE) reported that the national electrical system was fully synchronised.

Planned peak demand, available capacity and load shedding in Cuba, October-November 2024



Note: Data is not available for the blackout period, 19-22 October 2024.
Source: IEA analysis based on data from Ministerio de Energía y Minas (MINEM) and Unión Eléctrica (UNE) (2024).

Grid infrastructure and maintenance issues left millions of users without power in 2024

Venezuela suffered a major power outage on 30 August 2024 which left power cutoff to practically all households and businesses in the country. Various causes for the blackout had been reported, ranging from sabotage to technical reasons due to disinvestment and lack of maintenance in the power system. The impact of lightning, which caused a fault that was not properly isolated by grid protection equipment, was also identified as a probable cause. The outage affected the main refinery in the country, which processes up to 70% of Venezuela's exports of oil products, and essential services were covered by emergency generators. Power supply was restored for many areas around 12 hours later, although smaller-scale outages were frequent during the days after the event.

On 7 November 2024, major cities in **Nigeria** including Abuja, Lagos and Kano, suffered blackouts as the country's national grid collapsed. According to the Transmission Company of Nigeria (TCN), the blackout was due to a sudden rise in frequency from 50.33 Hz to 51.44 Hz because of a malfunction in one of TCN's substations, which led to "a series of lines and generators tripping that caused instability of the grid and, consequently, the partial disturbance of the system". This blackout was the second time in the week of 7 November and marked the tenth outage that affected the whole power system in 2024, with the main reason of outages being system failure. The National Bureau of Statistics (NBS) of Nigeria indicated recently that on average, a Nigerian household experiences electricity blackouts 6.7 times per week, with each outage lasting 12 hours. Reports have attributed the frequent outages in Nigeria to deteriorating power infrastructure, vandalism and inadequate gas supply for its gas-fired generating units, which account for over 75% of the country's power output. Among the potential causes, the mismatch between Nigeria's generation capacity and distribution capacity can be seen as the foremost issue that leads to the grid collapses. Despite Nigeria's total installed capacity of 13 610 MW and transmission capacity of over 8 100 MW, the country's distribution companies (DisCos) only have a distribution capacity of around 4 000 MW, which could lead to overloading that significantly affects grid. According to the National Orientation Agency (NOA) of Nigeria, "On 2 September, a peak generation of 5 313 MW was recorded, the highest in three years, but the DisCos rejected close to 1 400 MW due to their systems' fragility".

In early January 2024, the island of Panay, **Philippines**' fourth most populated island with a population of more than 4.5 million, suffered a four-day blackout caused by the tripping of major coal-fired power plants. Panay has an average demand of around 500 MW during peak periods and 300 MW in off-peak periods. The total dispatchable capacity on the Panay sub-grid is 730.4 MW, well above the grid's reserve requirements. During the incident, one of the four coal-fired power plants on the island, PEDC 3 (150 MW) was undergoing a planned maintenance shutdown, which reduced the reserve capacity to 580.4 MW. At 12:06 PM, 2 January, another coal-fired power plant, PEDC 1 (83.7 MW) tripped unexpectedly, resulting in only 309 MW of actual in-island generation, below Panay's demand of 450 MW. Panay's grid was interconnected with other islands, but transmission bottlenecks prevented sufficient inter-island power supply. At 2:19 PM, another system disturbance brought the remaining two coal-fired plants offline, triggering an island-wide blackout. In the aftermath of the blackout, it was concluded that if manual load-shedding measures were taken in the two-hour window between 12:06 PM and 2:19 PM, the island-wide blackout could have largely been avoided. Despite the Philippine Chamber of Commerce and Industry (PCCI)'s pledge to devise new solutions to prevent a repeat of the outages, a similar island-wide blackout took place in Panay on 2 March when three of the coal-fired power plants went offline unexpectedly during the regular maintenance shutdown of the other power plant.

Planning for resource adequacy: Emerging risks and trends in assessment methods

As electricity makes up a larger share of final energy demand, safeguarding its supply is key to ensure a range of services vital for modern societies. Recent power shortages underscore evolving uncertainties in the power sector to consistently meet demand, particularly under extreme – yet possible – conditions.

Historically, in power systems dominated by fossil fuels and large generators, supply shortages often stemmed from a combination of unrelated outages of large generators or interconnectors during periods of high demand. In emerging economies, these challenges were at times compounded by rapid demand growth outpacing new supply, leading to systemic load shedding to manage shortages.

Looking forward, growing risks stem from changing weather patterns and extreme weather events. In particular, extreme weather events have been identified as the main risk to reliability in many regions, for example by the North American Electric Reliability Corporation (NERC), which can have simultaneous, large impacts on power generation, grids and demand. These events can also put upstream fuel supply at risk, particularly evident for natural gas in freezing conditions if the infrastructure is not winterised sufficiently. Thus, power shortages due to extreme weather events can have a much wider impact, particularly if their effect on electricity demand and renewables output is coupled with thermal generator outages or fuel supply risks.

In this context, resource adequacy refers to the ability of power systems to reliably balance electricity supply and demand within an area under normal conditions in terms of weather and generator outages (among others), with the precise definition of normal conditions varying by jurisdiction. Adequacy is normally analysed in forward-looking studies that assess whether the available resources would allow the power system to meet certain reliability targets – such as specified limits on loss of load hours – in the period and conditions analysed.

Resource adequacy studies are foundational for key decisions across various time frames. In the short-term, a week or a season-ahead study influences operational decisions such as plant maintenance and reserve capacity procurement. On the other hand, studies investigating five or more years influence investments (and potential generator retirements) and policy decisions more directly. The implications for security, costs and investments mean that these studies need to accurately represent risks and the readiness of power systems to tackle them.

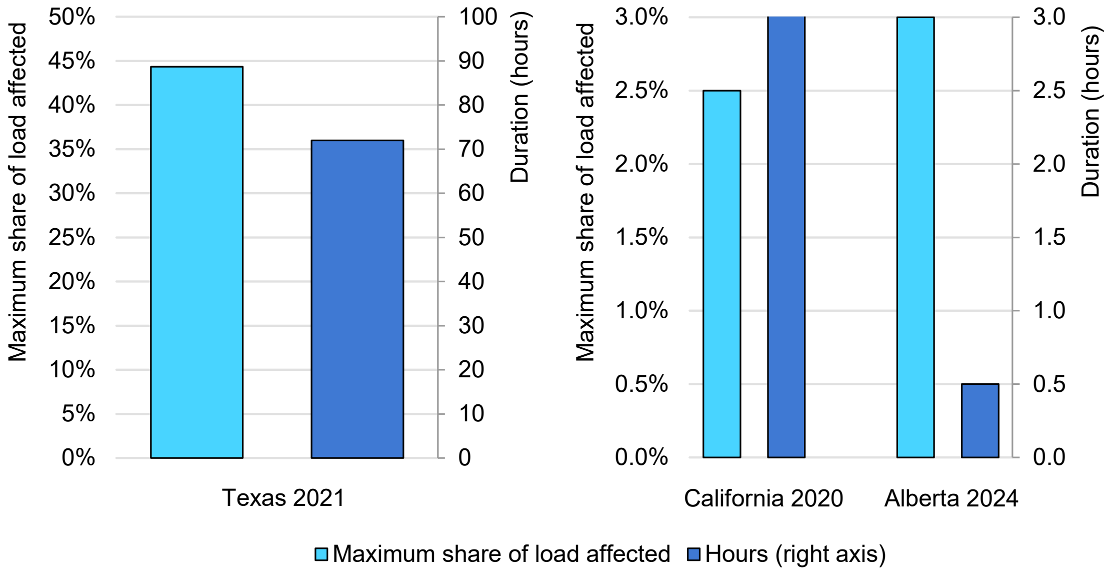
Recent events have highlighted adequacy risks worldwide. At the same time, several jurisdictions have been improving their resource adequacy studies, aiming to be better prepared for evolving demand, generation and weather conditions.

Surging electricity demand due to cooling needs during heatwaves or for heating in winter storms as a risk factor

In recent years, several countries faced significant power disruptions and adequacy risks. In some of these cases, risks were due to surging weather-related demand, for example during intense heatwaves, while in others they were mostly caused by supply-side shortcomings. In Mexico, an unexpected surge in electricity load in May 2024, which hit a record-high of nearly 50 GW (9% higher than 2023's peak) triggered load-shedding across 22 states, as the result of an insufficient reserve margin and exacerbated by a water shortage. Thousands of customers were affected as authorities implemented rotating blackouts to prevent grid instability.

In addition to extreme weather events, unplanned outages can put significant strain on the system if they occur during periods with tighter supply situations. On 5 April 2024, Alberta, Canada experienced load-shedding equalling up to 3% of total load over a 30-minute period (the first load shedding event since 2013). This occurred due to a series of unplanned outages coinciding with existing outages that reduced thermal generation supply by 4 GW and at a time when wind generation was 400 MW lower than expected.

Maximum share of load affected and duration for different power outages related to resource adequacy, 2020-2024

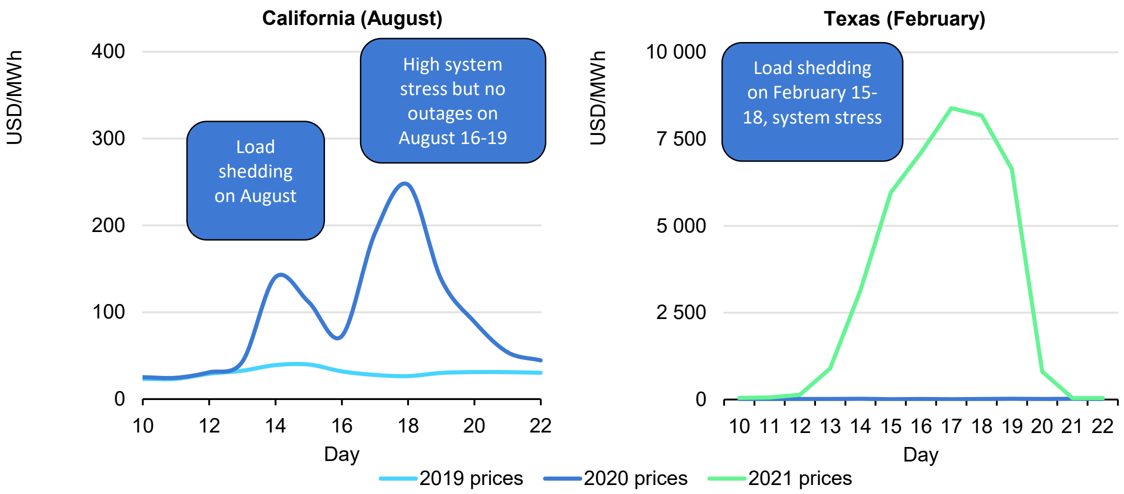


Sources: U.S. Energy Information Administration (2024), Real-time Operating Grid; FERC (2021), The February 2021 Cold Weather Outages in Texas and the South Central United States; CAISO (2021), Final Root Cause Analysis – Mid-August 2020 Extreme Heat Wave; Alberta Market Surveillance Administrator (2024), Alberta electricity system events on January 13 and April 5, 2024: MSA review and recommendations.

In Texas, ERCOT issued an Energy Emergency Alert Level 2 (EEA2) on 6 September, 2023 for the first time since winter storm Uri in February 2021. This measure – used in the case of severe scarcity – enabled ERCOT to access additional reserves only available in emergency conditions to avoid rolling outages. The EEA2 was triggered by strong customer demand due to extremely high temperatures, which pushed September demand to a record, surpassing 82 000 MW. The strong demand combined with low wind and solar PV generation, which led to lower operating reserves and a drop in system frequency.

System stress events have correspondingly led to surging electricity prices, adding to the already large impacts that losing power has on affected customers. During extreme events, such as the California heatwave in 2020 and winter storm Uri in Texas in 2021, prolonged outages affected thousands of customers, lasting several hours in California and up to multiple days in Texas. In these and other events, beyond the direct impacts on customers, electricity supplies saw wholesale price surge, providing a strong signal for demand response while also imposing significant cost burdens on customers exposed to them. In February 2021 in Texas, for instance, intra-day wholesale electricity prices hit the USD 9 000/MWh price cap in several periods during the cold snap. In Alberta on 5 April 2024, prices reached the price cap of CAD 1 000/MWh (Canadian dollar) for four consecutive hours and only returned to normal levels about 12 hours after load shedding finished.

Daily average wholesale electricity prices in system stress events in California (2020) and Texas (2021), 2019-2021

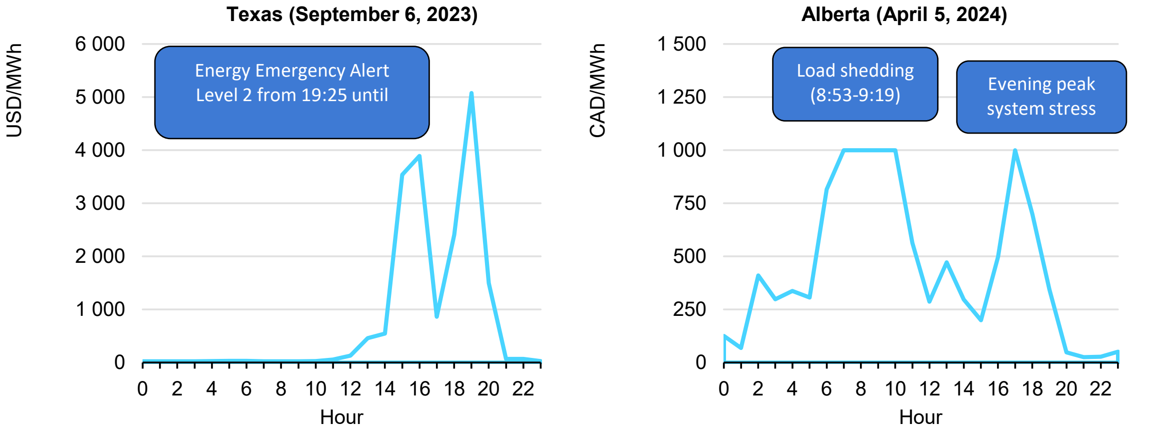


Note: The prices shown correspond to daily averages in each region.
Source: IEA (2024), Real-Time Electricity Tracker.

These events highlight the challenge of predicting specific abnormal conditions that can exacerbate vulnerabilities identified in adequacy studies. In North America, while the seasonal and long-term assessments by NERC did not indicate heightened risks for Alberta in 2024, unanticipated circumstances exposed vulnerabilities. For instance, an energy emergency was declared in Alberta on 13 January due to a cold snap that drove up demand, leading to low operating reserves.

The incidents discussed above underscore the importance of incorporating a broader range of weather-driven scenarios and coincident outages in adequacy studies to better prepare for such events, for example by influencing the sizing of reserves as an output of those studies.

Hourly wholesale electricity prices in system stress events in Texas (2023) and Alberta (2024)



Sources: IEA (2024), Real-Time Electricity Tracker; Alberta Electric System Operator (2024), Energy Trading System.

Extreme weather conditions are expected to remain a key driver of adequacy risks in many regions

Recent resource adequacy assessments studying the upcoming winter and three or four years ahead show tight adequacy conditions in several regions. In the near term, similar to recent events, these risks are mostly related to surging demand due to cold spells or heat waves, which could coincide with resource outages, low renewable generation and issues with fuel supply availability. These factors are also combined with potential impacts from generator retirements in some countries.

In **North America**, NERC's Winter 2024/2025 Reliability Assessment indicates that 9 out of 20 assessment areas are at elevated risk, potentially having insufficient operating reserves in extreme winter conditions. This can be exacerbated by gas supply risks in parts of the US Mid-Atlantic and Northeast due to legal challenges to the operation of an expanded gas pipeline. NERC'S 2024 Long-Term Reliability Assessment out to 2029 projects the Midcontinent Independent System Operator (MISO) assessment area to be at high risk, potentially not meeting adequacy requirements under normal conditions, and 10 other areas at elevated risk of not meeting them under above-normal conditions. These risks are stemming from a combination of factors, including demand growth, winter generator performance and fuel risks, and lack of capacity in some areas where generator retirements may not be fully offset by expected additions of new resources. These risks could be worsened if projects for new resources are delayed or cancelled.

In **Europe**, ENTSO-E's latest Winter 2024/2025 Outlook identified a positive adequacy trend for the upcoming winter overall. Countries such as Ireland and Finland present some adequacy risk if conditions such as cold days with abnormally low wind output materialise, particularly if they coincide with generator outages. By 2028, ENTSO-E's 10-year-ahead 2023 Resource Adequacy Assessment warns of adequacy risks in central and northern Europe, along with some island states. These risks stem from potential economic mothballing and decommissioning of some capacity resources, which may not be fully offset by expected capacity additions. The study warns that extreme climatic conditions could lead to adequacy risks in the region.

In **Australia**, AEMO's latest Electricity Statement of Opportunities reports for the National Electricity Market and the Wholesale Electricity Market (Western Australia) project adequacy risks to be above reliability standards in several regions in the 2024-2025 summer and in 2026-2028. For the 2024-2025 summer, these risks are mostly linked to potential conditions of high temperatures coinciding with low wind output or thermal generator outages. For 2026-2028, these risks are exacerbated due to the potential impacts of coal and gas-fired plant retirements, for example in New South Wales, Victoria and South Australia.

In the **southern and eastern Mediterranean countries**, the winter 2024/2025 adequacy study by Med-TSO analyses Morocco, Tunisia, Libya, Egypt, Jordan and Lebanon, and projects adequate resource availability for the first five countries. However, adequacy risks are identified in Lebanon, as it is already implementing load shedding due to domestic resources being regularly insufficient to meet demand.

In **Brazil**, the latest resource adequacy study within the 10-Year Energy Expansion Plan, published by the Energy Research Office (EPE) and the Ministry of Mines and Energy (MME), identified the need for additional capacity by 2027. Energy and power requirements show marked seasonality, peaking in the dry season and growing steadily over the decade. The study indicates a high risk of a power shortfall of 5.5 GW by Q3 2028, with 1.5 GW deficit emerging as early as September 2027, at the end of the dry season, in a scenario of severe drought and particularly low hydro output. In terms of energy needs, additional capacity will be required by late 2028, highlighting the need for expansion efforts to ensure adequacy.

In **India**, resource adequacy assessments are carried out by state, following guidelines from the Central Electricity Authority. Requirements are split into additional renewable energy and storage resources to ensure fulfilment of

Renewable Purchase Obligations (RPO) and additional thermal capacity. Given the fast growth rate of peak demand in the country (see Demand, *Strong growth in peak electricity load in India amid economic growth and rising AC usage*), mainly due to the use of air conditioning during heatwaves, most states identify further requirements by 2028. For example, Uttar Pradesh will need to contract for an additional 5 GW of coal-fired capacity and 8 GW of solar PV capacity by mid-2027.

Countries are increasingly using stochastic methods to make adequacy studies more robust

Adequacy assessments face significant uncertainties due to fluctuating electricity demand, extreme weather events, and the availability of generation resources. The increased frequency and intensity of extreme weather makes it harder for studies to capture all potential scenarios. Furthermore, the uncertainty on how much demand flexibility can be utilised during a stress event, and the rapid growth in demand from electrification – particularly for cooling, data centres and transport – adds to the challenges that adequacy studies must tackle. When looking beyond five years ahead, resource adequacy studies can better capture uncertainties by relying on several scenarios, focusing on modifications of key assumptions such as the future installed generation, storage, as well as demand-side flexibility resources. Additionally, variations on assumptions such as infrastructure availability and electricity demand levels can also help better capture longer-term uncertainties.

One traditional approach involves projecting adequacy for a certain planning reserve margin, which reflects the share of additional available capacity over the projected peak demand period. This is done with a deterministic approach, using static projections for peak demand and assumptions for resource availability. While this approach is straightforward, it has significant limitations, particularly in accounting for the variability and uncertainty inherent in modern power systems. Fixed assumptions fail to capture the dynamic nature of demand fluctuations, renewable energy variability, and the impact of extreme weather events. As a result, this method may either overestimate or underestimate the reliability of the system, leading to inefficiencies in resource planning or reliability risks. It also does not provide insights on key aspects such as the likelihood of an outage, potential unserved energy or the duration of the shortages.

Some of these limitations can be addressed using another traditional approach called probabilistic convolution. This method is based on doing mathematical operations using the probabilistic distributions of variables such as demand, generation and outages. While this method can provide additional insights such as the total expected hours with outages and expected unserved energy over the studied period, it has at least three notable limitations. First, it assumes a simplified representation of the power system. Second, it does not inherently account for temporal dependencies, such as prolonged weather events, where energy availability may be more of a concern than the capacity available, particularly when considering the contributions of storage and demand response. Third, its representation of rare but high-impact shortages (and of their causes) is limited.

To address the limitations of traditional methods and better represent key aspects such as energy storage and demand response, stochastic modelling approaches, such as Monte Carlo methods, are increasingly used. These approaches use random sampling of probabilistic input variables, including demand, generation, and weather patterns, to simulate numerous scenarios and generate a range of potential outcomes. Unlike simpler probabilistic approaches, simulation-based methods enable detailed system representations, like economic dispatch models.

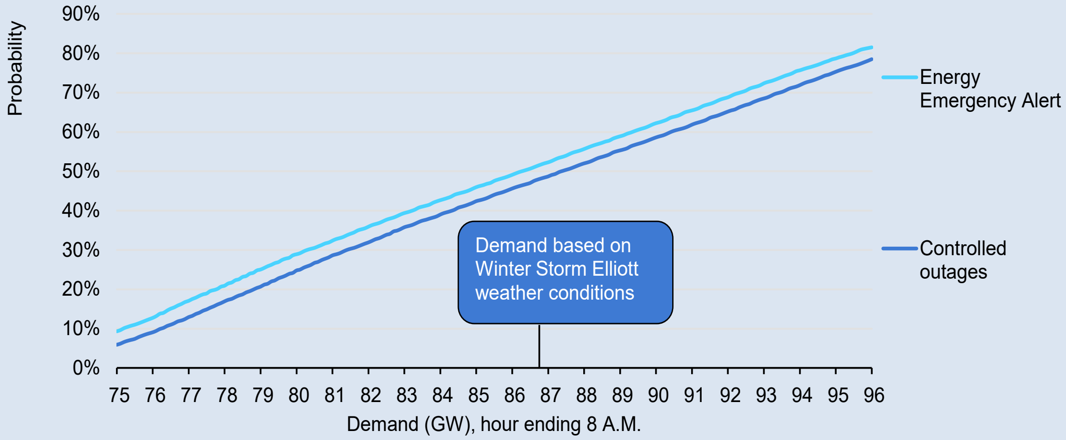
Beyond a more accurate representation of the underlying power system, notable advantages of Monte Carlo methods include improved insights into the duration, magnitude and frequency of shortages, as well as the ability to incorporate sequential modelling. This is particularly important for energy-constrained resources such as storage and demand response, in which the energy available at one moment is partially linked to past decisions. Additionally, these methods allow for a better representation of unexpected events and their interactions, such as varying weather conditions, demand fluctuations and capacity availability. They are particularly valuable for representing tail risks and to understand their causes as they allow for an isolated deep dive into potential high-impact events or periods. Monte Carlo methods are increasingly used, for example, by entities such as operators under the North American Reliability Council, by ENTSO-E, the Mediterranean TSOs, and in countries such as Australia, South Africa, India, and Brazil.

Enhanced representation of weather patterns and extreme events

Changing weather patterns and extreme weather events are gaining more attention in resource adequacy studies. On the one hand, assessing adequacy using several weather years, stemming from historical or projected future patterns, can help account for uncertainties on weather pattern developments. Studies for North America, Australia and by the Mediterranean TSOs are using historical weather data to assess future adequacy under different annual weather patterns. For example, the study of the Mediterranean TSOs for the upcoming winter 2024/2025 uses weather years, including a sensitivity on the most severe Monte Carlo climatic year. Moreover, in 2024, ENTSO-E started to use climate projections instead of reanalysis of historical weather years to better account for future changes in weather patterns.

On the other hand, specifically modelling the impacts of heatwaves, cold spells and other extreme events helps understand the potential impacts of tail risks tied to climate and the preparedness of the system to withstand them. While there is still room for improvement in identifying and analysing high-risk events, some adequacy assessments are already including specific analysis, with a focus on extreme weather events. For example, ERCOT's resource adequacy study for January 2025 includes a specific analysis of the adequacy risks due to extreme winter storm conditions. Using a Monte Carlo simulation combined with a stress-testing approach, the analysis reveals a 50% likelihood of controlled outages during the hour of highest projected system stress in January 2025, should weather conditions comparable to Winter Storm Elliott (2022) occur.

Extreme winter storm event simulation results, ERCOT, January 2025



Notes: ERCOT = Electric Reliability Council of Texas. Hour ending 8 A.M. is the hour with the highest risk of reserve shortfall in ERCOT's probabilistic assessment for January 2025. An Energy Emergency Alert is issued if operating reserves fall below 2 500 MW and are expected to stay below that level for at least half an hour.
Source: ERCOT (2024), Monthly Outlook for Resource Adequacy (MORA) January 2025, as modified by the IEA.

Adequacy studies and reliability standards are recognising the value of multi-metric approaches

Along with improvements to adequacy assessment methods, there is also a need to adopt more refined and multiple metrics in adequacy studies and reliability standards. Electricity shortages vary in magnitude, duration, frequency and timing, making reliance on a single metric, such as the traditionally used planning reserve margin or loss of load expectation, potentially insufficient, as no single measure can fully capture all aspects of reliability. This is particularly true if adequacy risks increasingly stem from rare, high-impact events, such as extreme weather events or prolonged low renewable generation. Multiple metrics enable a more comprehensive assessment, including both everyday risks and rare but severe events, as highlighted by the IEA, the Energy Systems Integration Group and the Electric Power Research Institute. This approach helps policy makers better understand reliability risks and balance them with cost considerations.

Leveraging probabilistic convolution and Monte Carlo methods, several adequacy studies are reporting various probabilistic metrics to have a better reflection of reliability risks. Widely used metrics include the Expected Unserved Energy (MWh/period) to measure the total size of the outages and the Loss of Load Expectation (hrs/period) to project the total hours of load shedding over the studied period. Tail risks can be assessed using metrics such as the 95th-percentile (P95) of an indicator such as the loss of load hours in the period, for example as done in the adequacy studies by ENTSO-E and the Med-TSOs. Monte Carlo methods, in particular, enable the reporting of additional metrics, such as the number of shortfall events in a specific period and their average duration, and risk profiles for specific times in the period studied, for example during early evening hours.

Beyond their inclusion in resource adequacy studies, multi-metric approaches are also being adopted in reliability standards. This can serve as a method to define the tolerable risks in several dimensions of outages, such as how often they occur, how long they last for, and their size. For instance, the Public Utilities Commission of Texas approved in August 2024 an update to the reliability standard to include three criteria: frequency, duration, and magnitude.

Regional Focus

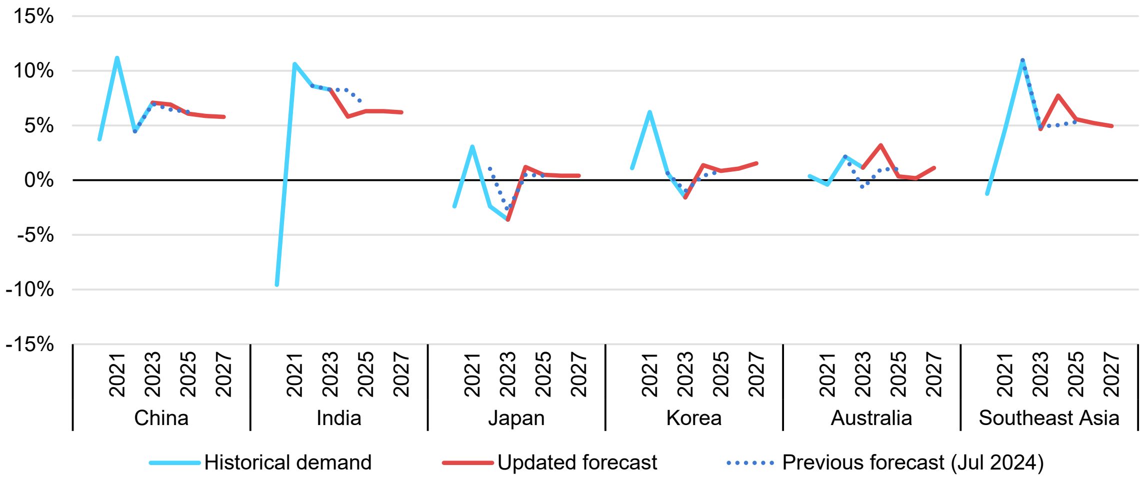
Asia Pacific

Solar PV set to continue its rapid growth while coal-fired power generation stabilises

The Asia Pacific region saw a sharp 6% rise in electricity demand in 2024, providing almost 75% of total growth globally. China and India were the main engines powering the expansion, at 7% and 5.8%, respectively, and combined accounted for 85% of the increase in consumption in the region. China's gains were largely driven by a stronger industrial sector, rising cooling demand and the expansion of both data centres and 5G networks. At the same time, India's robust economy and higher cooling needs amid severe heatwaves bolstered demand. We expect the region to register growth of 5.2% in our 2025-2027 outlook period.

Renewables posted the strongest increase in 2024, up by 14% y-o-y, while coal, the primary source of the region's electricity supply, rose by a much smaller 2%. However, coal's share of 55% contracts to 48% by the end of our forecast. By contrast, renewables' share rises from 29% to 37% by 2027. All renewable sources for power generation were up in 2024, with solar PV capturing the largest gains (32%), followed by wind (11%) and hydro (9%). Renewables are forecast to outpace growth from all other sources in 2025-2027, rising on average by 14%. Wind and solar will account for much of the increase, at an average 18% and 26%, respectively, over the period. We expect solar PV will surpass hydropower to become the biggest source of renewable power generation in the region by 2027.

Year-on-year percent change in electricity demand, Asia Pacific, 2020-2027



Note: Data for 2025-2027 are forecast values. The years on the x-axis start at 2020.

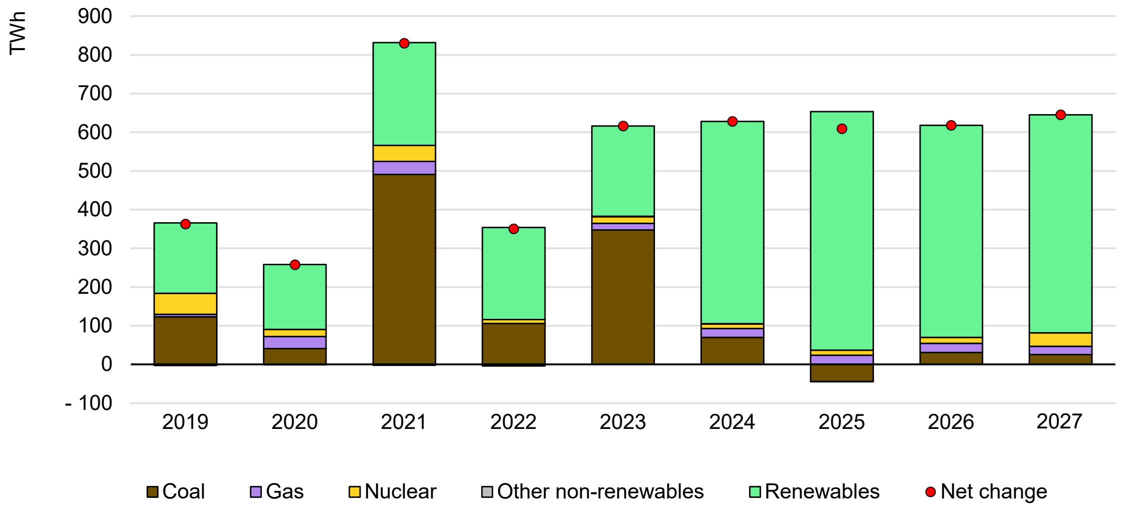
China

Solar PV and wind to meet most of the demand growth in 2025-2027, driving an increasing need for more system flexibility

Electricity demand in China rose by a robust growth rate of about 7% in 2024, underpinned by the acceleration of electrification across end uses, in line with the 7.1% rise in 2023. The higher growth in electricity demand was due to a multitude of factors, including the rapid expansion of energy-intensive manufacturing for solar PV modules, batteries and electric vehicles, as well as more stable production in traditional industries. Outside of industry, key contributors were increased space cooling needs due to intense heatwaves, growth in data centres and 5G networks, and rising demand for EV charging.

With the country's economy expected to slow as it shifts away from traditional heavy industry, we forecast the pace of electricity demand growth to ease gradually to 6.1% in 2025, 5.9% in 2026 and 5.8% in 2027. (see Demand, *Electricity demand in China has been growing faster than GDP since 2020.*).

Year-on-year change in electricity generation in China, 2019-2027



IEA. CC BY 4.0.

Notes: Other non-renewables include oil, waste and other non-renewable sources. Data for 2025-2027 are forecast values.

Despite strong electricity demand growth in 2024, coal-fired output was up by only 1.2% due to the rapid expansion in renewables generation. Hydropower increased by a substantial 11%, and remains China's largest source of renewable power generation. Solar PV generation posted strong growth of about 45% y-o-y, which corresponds to roughly an additional 265 TWh – roughly equivalent to the total electricity consumption of Spain. Wind power rose by 12% (+105 TWh). Over the next three years, China's solar PV and wind generation are expected to continue their strong growth at average annual rates of almost 30% and 18%, respectively, and both sources are individually set to surpass hydropower by the end of 2027. Generation from solar PV and wind are forecast to meet more than 85% of the increase in China's electricity demand over our outlook period, which will correspondingly constrain coal-fired power generation.

In July 2024, China reached a significant milestone in its clean energy transition, surpassing 1 200 GW of wind and solar PV capacity – six years ahead of its target. However, this rapid increase presents new challenges, particularly concerning system flexibility. In response, China is implementing measures such as accelerating the construction of energy storage facilities, including electrochemical and pumped storage, promoting the development of virtual power plants and speeding up the establishment of provincial and interprovincial spot markets.

Coal's role in providing flexibility will expand, alongside other emerging flexible energy resources

Despite strong growth in renewables, coal will continue to play an important role in Chinese power generation needs through 2027 amid continued robust electricity consumption. We expect coal-fired generation to roughly plateau in the forecast period. At the same time, coal's share in total generation will fall from almost 60% in 2024 to 50% in 2027 as it gives way to expanding renewable sources, with its role shifting from a core energy source to primarily supporting system flexibility and ensuring adequacy. In November 2021, China's National Development and Reform Commission (NDRC) and the National Energy Administration (NEA) jointly mandated that newly constructed coal units should fulfil flexibility requirements, and all retrofittable coal units (estimated at 500-700 GW) undergo flexibility modifications by 2027, enabling them to reduce their minimum output to less than 35% of rated capacity (and less than 40% for power-heat cogeneration units). This policy has accelerated retrofits, particularly in VRE-heavy regions. Each Five-Year Plan (FYP) since 2016 has emphasised retrofitting coal-fired plants to enhance flexibility. Retrofits can be carried out in a few months and are aimed at lowering the minimum operating range, increasing the ramping capability, and reducing the start-up time to allow for frequent up and down cycling. In the 14th FYP (2021-2025), the speed of retrofitting picked up, with 300 GW of coal capacity already retrofitted from 2021-2023, surpassing the plan's target of 200 GW.

Gas-fired power generation is projected to maintain steady growth at an average annual 7% in 2025-2027, following an 8% increase in 2024. Demand for system flexibility is one factor supporting higher use. Gas plant characteristics make them a high-quality source for peak shaving and frequency regulation in the power system, including more flexible startup and shutdown, faster ramping rates, and lower carbon emissions compared to coal generation.

New policies have been announced related to the integration of variable renewable energy sources

In 2024, China issued multiple policy documents, including the Action Plan for Accelerating the Construction of a New Power System and Guidance on Implementation of Renewable Energy Substitution Actions, among others, to promote the construction of a new power system dominated by variable renewable energy (VRE), as well as the replacement of traditional energy sources with renewables. On 8 November 2024, China officially introduced the Energy Law of the People's Republic of China, which took about 18 years to formulate and provides comprehensive and systematic regulations on energy planning, development and utilisation, market systems, reserves and emergency response, as well as technological innovation. The law explicitly supports prioritising the development of renewable energy, establishing its primary role in the energy mix. This legislation is set to guide China in further reducing its reliance on fossil fuels in the future.

However, there are challenges to integrating large amounts of VRE into the grid and this could affect renewable generation trends in the near term. In the IEA’s report Meeting Power System Flexibility Needs in China by 2030, the first half of 2024 saw an uptick in wind and solar curtailment rates in China. This was particularly pronounced in the Hebei province in the north of China where monthly curtailment rates were as high as 16% for wind and 12.6% for solar PV. These curtailments were largely a result of grid congestion and insufficient flexibility. Addressing these issues remains a priority to unlock the full potential of a VRE-dominated grid. China is actively developing various types of system flexibility resources such as energy storage, virtual power plants and demand-side response to meet the growing demand for flexibility. According to the IEA’s Announced Pledges Scenario (APS), 58% of flexibility needs in China in 2030 can be fulfilled with non-fossil fuel resources.

In early February 2025, China announced a market-driven reform of its renewable power pricing system. According to the new framework, all renewable electricity generation will participate in the power market, with a relaxation of price caps in the spot market. Furthermore, fixed feed-in tariffs will be phased out and replaced by a contract for difference mechanism.[25]

[25] The forecast is made based on the policy framework as of December 2024.

India

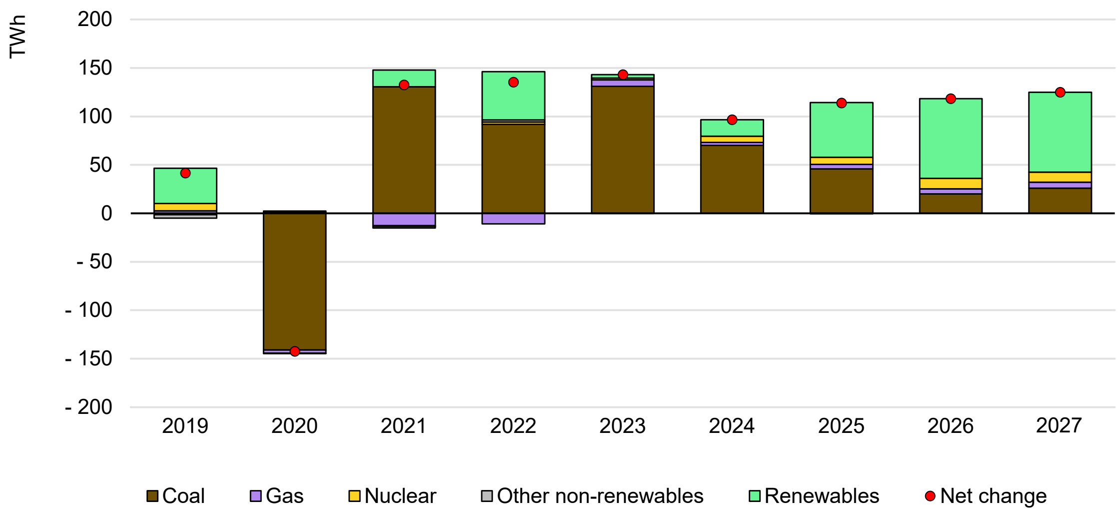
Electricity demand continued to grow strongly amidst robust economic growth and record heatwaves

Electricity demand in India increased by 5.8% in 2024 y-o-y, driven by a rapidly expanding economy that is estimated to grow by 7% in 2024, according to the IMF, and intense heatwaves, which further boosted power needs. Peak power use reached a record 250 GW in May, surpassing the previous high of 243 GW recorded in September 2023. Total electricity generation increased by 15% y-o-y to 168 TWh in May compared to the same month in 2023, driven by an unprecedented heatwave that led to a spike in cooling demand. According to India's Ministry of Power, by 2030 peak electricity demand is forecast to exceed 400 GW, with 65% of capacity expected to come from non-fossil fuel sources.

In February 2023, the Ministry of Power invoked Section 11 of the Electricity Act, 2003, which directed all imported coal-based power plants to operate at full capacity to avoid electricity shortages. This was extended multiple times, and the latest extension mandated that imported coal-based power plants operate at full capacity until the end of February 2025. Section 11 was also used to direct gas-fired power stations to operationalise according to government instruction for the months of May and June last year.

Hydropower saw an increase of 2.5% y-o-y, following a large 17% decrease in hydropower generation in 2023. Hydropower output in 2024 was lower than in any other year since 2018, except for 2023. The drought conditions continued in 2024, we assume hydropower generation to recover over outlook period, subject to hydrological conditions.

Year-on-year change in electricity generation in India, 2019-2027



Notes: Other non-renewables includes oil, waste and other non-renewable. Data for 2025-2027 are forecast values.

Coal-based generation remains the main source of electricity while renewables continue to grow

Coal-based generation remains the backbone of India's electricity mix, accounting for 74% of the total share in 2024, but is projected to fall to a smaller 67% by 2027. While coal remains the primary source, gas-fired generation is also rising, though from a much lower base, with an estimated growth of 6% y-o-y in 2024, and further increases are forecast for the next three years at an average 9% annually.

The share of renewable energy is on course to significantly expand as new capacity additions in wind, solar and hydropower come online. Although coal-based power generation has grown at a 4% compound average growth rate (CAGR) from 2018-2024, this is projected to slow to around 2% between 2025-2027, reflecting a gradual shift towards cleaner energy sources.

According to the Ministry of Power, India's thermal power capacity is projected to reach 283 GW by 2032, up from the current 218 GW. The government plans for a minimum of 80 GW of new capacity to come from coal-based power plants, complementing the anticipated 500 GW from non-fossil fuel sources by 2030.

Rapid expansion of renewable power generation to see double-digit growth through 2027

Renewables currently constitute 21% of the energy mix and are expected to rise to 27% by 2027. India aims to have 500 GW of non-fossil fuel capacity by 2030 to accelerate the clean energy transition and help achieve the country's target of net zero emissions by 2070.

Solar PV remains the fastest growing renewable generation technology, rising by over 28% between 2025-2027. India's PM-Surya Ghar: Muft Bijli Yojana initiative – its rooftop solar scheme for residential consumers – was launched in February 2024, with the aim of providing systems that can generate over 300 kWh of electricity per month for 10 million households and enable the addition of a total of 30 GW capacity. With a financial outlay of over INR 700 billion (Indian rupees), the scheme would subsidise up to 60% of the capital cost of the rooftop plant to consumers. The plan also has earmarked funding to incentivise distribution companies facilitating rooftop adoption.

India approved amendments to the Electricity (Rights of Consumers) Rules in 2024, aimed at streamlining the process for obtaining new electricity connections, simplifying the installation of solar power plants and empowering consumers. Under the revised rules, systems with a capacity of up to 10 kW are exempt from requiring a technical feasibility study by distribution companies (discoms), and installations are deemed approved if feasibility assessments are not conducted within 15 days.

The National Electricity Plan (Transmission) was launched in October 2024, which aims to transmit 500 GW of renewable installed capacity by 2030 and 600 GW by 2032, as well as set a target of 47 GW for battery energy storage systems (BESS) and 31 GW for pumped hydro storage plants. It also includes plans for transporting green hydrogen and green ammonia to manufacturing hubs at coastal locations. The plan will provide visibility to investors on the expenditures that will take place until 2032.

In 2024, India became self-sufficient in solar module manufacturing. In line with the domestic content requirement (DCR), India has reached a module manufacturing capacity of 50 GW for solar PV and 6 GW for solar cells. The Ministry of New and Renewable Energy noted that while the country has the ability to produce enough solar modules to meet domestic needs, it has yet to build up the production capacity necessary to become a major exporter.

Wind power generation has grown at 7% CAGR between 2018-2024 and is expected to increase by 11% CAGR between 2025-2027. The government approved viability gap funding of INR 74.5 billion to set up the first ever offshore wind projects in the country. This included funding for the installation and commissioning of 1 GW of offshore wind projects, with 500 MW off the coast of both Gujarat and Tamil Nadu.

Hydropower generation is assumed to increase at around 7% CAGR in 2025-2027. The Central Electricity Authority estimates the potential for small hydropower projects at 21.1 GW across 7 133 potential sites focusing mainly on run-of-river, canals and dam-toe projects. The government approved central financial assistance (CFA) of INR 41.4 billion to ensure equity contribution in hydroelectric projects across all northern states. In addition, budgetary support of INR 124.6 billion for the cost of enabling infrastructure for hydropower has also been approved. This scheme targets installation of 31.4 GW capacity by 2032.

As part of the National Green Hydrogen Mission, launched in 2023 to accelerate deployment of green hydrogen, the government issued guidelines for pilot projects in the transport, shipping and steel sectors. Accordingly, with an anticipated decrease in renewable energy costs and electrolyser prices, green hydrogen could become increasingly cost-competitive in the coming years, promoting broader adoption across these key sectors.

In 2024, nuclear generation rose by 13% y-o-y. According to the Department of Atomic Energy (DAE), India will triple its installed nuclear power capacity from 8.2 GW to 22.5 GW in 2031-2032. Current installed capacity is spread across 24 nuclear power reactors. India is currently advancing the development of pressurised heavy water reactors (PHWRs) and is focusing on the Bharat Small Reactor (BSR) for localised, or captive, nuclear power generation. Additionally, the DAE is working on a 220 MW Bharat Small Modular Reactor (BSMR) designed with light water reactor technology, to support flexible and scalable nuclear power solutions.

India is also developing 4 GWh of battery energy storage through a recently approved scheme, which will provide a subsidy of up to 40% of the capital cost of the system. A minimum of 85% of the BESS capacity will be offered to distribution companies to allow for greater integration of renewable energy into the grid. The Union Budget 2024-2025 proposed a policy to promote pumped hydro storage projects for the smooth integration of the growing share of renewable energy.

Japan

Electricity demand returns to growth after two years of declines, boosted by weather impacts

Following two years of consecutive declines, Japan's electricity demand rose by 1.2% y-o-y in 2024, supported by cold weather in March followed by a heat wave in the summer. In March, electricity demand was around 10% higher than the previous year due to these adverse weather conditions. During the summer period (between July and September) electricity demand increased by about 2% y-o-y. The Japanese government provided subsidies for electricity and gas bills from January 2023 to May 2024, renewed these subsidies from August to October 2024, and again from January 2025 to March 2025. The latest renewal is expected to provide relief for consumers, but they could correspondingly also support higher electricity consumption in 2025.

Annual electricity demand is forecast to rise by approximately 0.4% on average each year from 2025 to 2027, mainly due to the expansion of the electricity-intensive AI and semiconductor industries. Japan’s Organization for Cross-regional Coordination of Transmission Operators (OCCTO) issued a report, the Aggregation of Electricity Supply Plans for Fiscal Year 2024, confirming the growth trend in its longer-term 10-year forecast for electricity demand at an average annual rate of 0.4% from FY2023 to FY2033. The report noted a stronger economy, coupled with the rising number of both data centres and semiconductor factories, will outweigh the impact of energy saving measures and a declining population, which have contributed to the steady contraction in electricity demand for the past decade.

In 2024, nuclear generation rose by 8% y-o-y following to the restart of the Takahama 1 and 2 reactors in the second half of 2023 and the return to operation of the Onagawa Unit 2 in November 2024 and the Shimane Unit 2 in December. The restart of both plants will increase nuclear power use in 2025, and we anticipate that generation will be up to 25% higher in 2025 compared to 2024, followed by an average annual increase of 10% over the 2026-2027 period. Power generation from renewable resources was up by 7% y-o-y in 2024, and we predict steady growth of close to 8% annually to 2027. Gas-fired power generation remained relatively flat in 2024. Coal-fired power generation is estimated to have decreased by 2% y-o-y. Both coal-fired and gas-fired power generation are forecast to contract by 16% and 14%, respectively, in 2027 compared to 2024, as the share of low-emissions sources continues to rapidly expand.

There are still several nuclear reactors in the restart schedule during our forecast period. In April 2024, Tohoku Electric Power announced the postponement of the completion schedule of safety measures for Higashidori Unit 1. The plant previously aimed to complete the safety measures in FY2024. In August 2024, it was announced that there was going to be a delay in the completion of safety measures of Tokai Unit 2 from September 2024 to December 2026. In addition, Japan's Nuclear Regulation Authority (NRA) said that it would not grant permission for changes to the reactor installation at the Tsuruga Unit 2. This was the first time that the NRA concluded that it could not clear a reactor's safety compatibility examination.

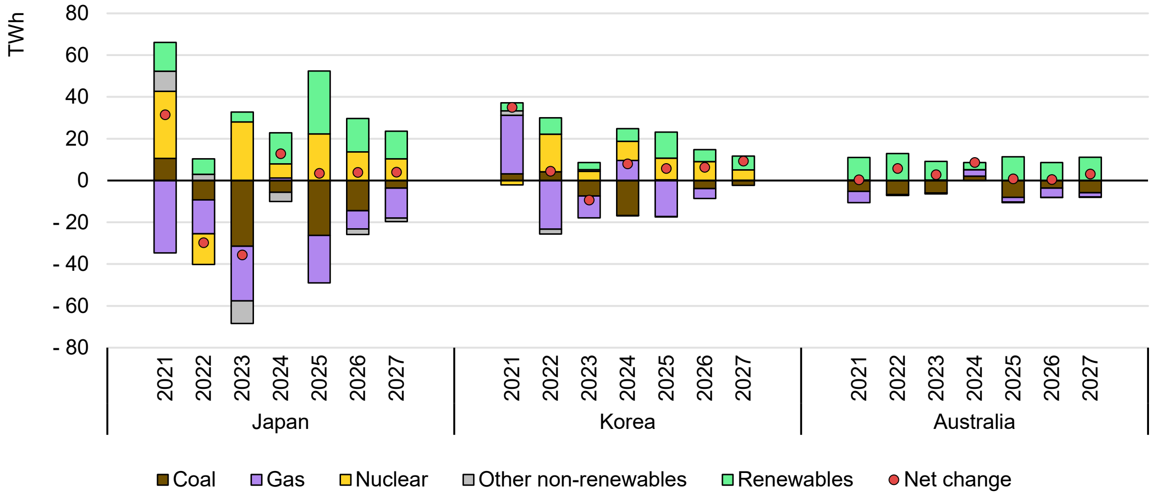
Initiatives to secure power supply capacity from low-emissions sources are important to tackle both decarbonisation and electricity demand growth, with auctions playing an important role. According to the result of the first long-term decarbonised power supply auction announced in April 2024, 4 GW of decarbonised power sources were awarded. It included 0.6 GW pumped storage hydropower, 1.1 GW battery storage, 0.06 GW hydrogen co-firing capacity, 0.8 GW ammonia co-firing capacity, 0.2 GW biomass power and 1.3 GW nuclear power. In addition, 5.8 GW of LNG-fired power generation plants were awarded. Furthermore, supply capacity reserved on the capacity market has been delivered since April 2024, which is expected to improve market stability.

Japan drafts new plan that could double targets for renewable energy in power generation by 2040

Japan's 2023 Basic Policy for the Realization of GX calls for the country to achieve a target of 36-38% for renewable energy sources in the power generation mix by FY2030. This includes several actions such as the development of power grids that can respond to fluctuating output and targeting the early adoption of next generation (perovskite) solar cells that can help with the wider implementation of solar PVs, which are expected to be a significant source of supply contributing to the rising share of renewables in power generation.

The Japanese Ministry of Economy, Trade and Industry (METI) released a new draft energy plan targeting 40-50% renewable energy in power generation by fiscal year 2040 (up from 24% in 2024), which would make renewables the largest source in the generation mix. The plan also sees a comeback for nuclear energy, with 30 reactors expected to restart by 2030 for a share of 20% in power generation by 2040 (up from 9% in 2024). According to the plan, thermal energy's share would decline to 30-40% by 2040, down from 66% in 2024.

Year-on-year change in electricity generation in Japan, Korea, and Australia, 2021-2027



Notes: Other non-renewables includes oil, waste and other non-renewables. Data for 2025-2027 are forecast values.

Korea

Share of low-emissions energy in electricity generation exceeded the 40% mark in 2024 and set to reach 47% by 2027

Korea's electricity demand rose by 1.4% y-o-y in 2024, mainly due to a summer heatwave. Peak electricity demand averaged almost 88 GW in August 2024, an increase of 6% compared to 2023. In addition, peak demand in September averaged 78 GW, the highest level ever recorded for this month.

According to the 11th Basic Plan for Electricity Supply and Demand strategy draft announced in May 2024, power demand in 2038 is projected to reach 129 GW, increasing by around 30% from the peak demand level in 2023, in order to meet the growing energy needs of data centres and semiconductor foundries. This plan aims to expand renewables capacity to 72 GW by 2030, up from 23 GW in 2022. Additional nuclear reactors are set to be built by 2038, and includes a small modular reactor (SMR) of 0.7 GW. The plan also calls for converting coal-fired power plants into gas-fired, and 12 ageing coal-fired power plants are set to be converted into low-emissions sources such as pumped storage hydro or hydrogen power plants.

In 2024, the Shin Hanul-2 (1.4 GW) began commercially operating, while Saeul-3 (1.4 GW) and Saeul-4 (1.4 GW) are under construction. In September 2024, the Nuclear Safety and Security Commission approved construction permits for the Shin Hanul-3 (1.4 GW) and Shin Hanul-4 (1.4 GW) reactors.

Nuclear generation rose by around 5% y-o-y in 2024 as new plants came online during the year. Gas-fired output rose by 6%, led by higher electricity demand from the summer heatwave. In addition, generation from renewable resources was up by a sharp 12% y-o-y. By contrast, coal-fired generation fell 8% y-o-y. We forecast that electricity demand will grow annually on average by 1.2% out to 2027. Nuclear and renewable power generation is expected to be 11% and 42% higher, respectively, in 2027 versus 2024. The share of nuclear power in total power supply in 2027 will account for 34%, up from 32% in 2024, and renewables will rise to 13% in 2027 from 9% in 2024.

The Ministry of Trade, Industry and Energy (MOTIE) established a hydrogen bidding market in 2023. In 2024, a general hydrogen bidding market process was conducted, aiming to accelerate the installation of distributed energy resources, with bidding volume reaching 1 300 GWh and power generation contracts spanning 20 years. Commercial operation must commence by 2026 following two preparatory years. In May 2024, MOTIE announced the launch of the world's first clean hydrogen power bidding market, aiming to auction 6 500 GWh of electricity generated from clean hydrogen over a 15-year period. Six power plants participated in the bid, however, only one bidder, with 750 GWh, was selected from the first round of bidding.

In May 2024, MOTIE announced its Strategies for Expanding Supply and Strengthening Supply Chain for Renewable Energy, which aims to expand renewable energy capacity and strengthen the domestic supply chain. This plan also aims to accelerate the adoption of renewable energy by supporting site selection, revising the Renewable Portfolio Standard system and easing PPA regulations. In August 2024, MOTIE released the Offshore Wind Power Competitive Bidding Roadmap, with up to 8 GW available for bids in separate auctions from the second half of 2024 to the first half of 2026.

Australia

Electricity output from renewable energy sources is set to surpass coal-fired generation by 2027

Electricity demand in Australia rose by 3.2% in 2024, largely due to a combination of a stronger economy amid population growth of 2.5% in 2023, as well as higher temperatures increasing power usage during peak demand periods. Electricity consumption is forecast to rise by an annual average of 0.4% in 2025-2027.

Efficiency is expected to continue playing an important role in limiting demand growth, with multiple initiatives, such as the Energy Savings Package, implemented in 2024. This includes a Community Energy Upgrades Fund programme, which allocates AUD 100 million (Australian dollar) as co-funding for energy upgrades at existing local government facilities.

Generation capacity additions in the coming years are anticipated to come mostly from renewable sources, with a small contribution from new gas-fired capacity. In 2024, almost 5.4 GW of renewables capacity was installed, including over 4.4 GW of solar PV and around 1 GW of wind. We expect a similar pace of installations to be maintained over the forecast period. The construction of the Tallawarra B gas-fired power station was completed in early 2024, and is Australia's first peaking power station with direct emissions offset. In other words, they will fully offset their emissions with Australian Carbon Credit Units. Its fast-start gas turbine can be brought online to full load within 30 minutes, generating 320 MW. The Hunter Power Project is an open cycle gas turbine (OCGT) anticipated to be online in June 2025. The OCGT is capable of initially running on up to 15% hydrogen. The ability to run on hydrogen is dependent on the balance of plant modifications and the availability of green hydrogen. The power station will have a capacity of up to 750 MW, with 660 MW supplied to the grid initially. The 200 MW/400 MWh Rangebank Battery Energy Storage System officially commenced full operations in December 2024. In 2024, Australia reached a storage capacity of 3 GW, including batteries, virtual power plants and pumped hydro.

In 2024, total renewable generation reached 34% of the electricity mix, consisting mainly of solar (16%), wind (11%) and hydropower (5%). The share of renewables is expected to reach 44% in 2027, surpassing coal for the first time and driving a steady decline in fossil fuel generation. Coal's share fell from 47% of the mix in 2023 to 46% in 2024 and is expected to decline to 39% in 2027. The share of gas remained constant at 18% in 2024 and is forecast to drop to around 15% by 2027. Despite the rising contribution of renewables and declining coal share, in 2024 Australia saw a rise in total emissions (2.3%) because coal and gas output rose to meet the increase in demand. We expect total power generation emissions to fall by around 5% per year on average over the 2025-2027 forecast period.

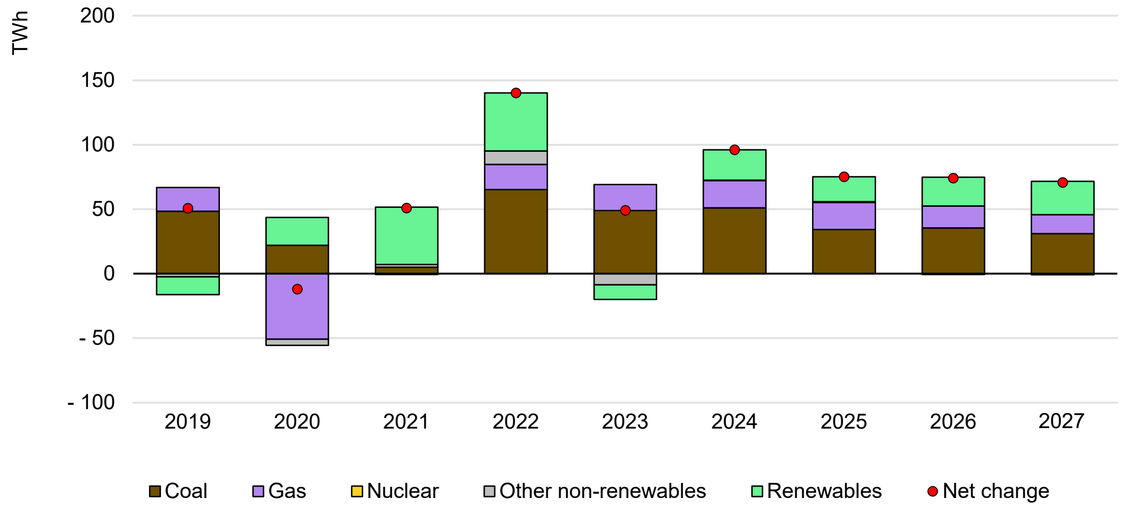
Southeast Asia

Almost 70% of additional electricity demand in 2025-2027 is expected to be met by fossil fuel-fired generation

Electricity demand in Southeast Asia grew significantly in 2024, recording estimated growth of 7.4% y-o-y. The two biggest consumers of electricity in the region, Indonesia and Viet Nam, were also the two countries that saw the highest levels of demand growth. Electricity demand was around 10% higher in both

Indonesia and Viet Nam, which combined represented two-thirds of all additional electricity demand in Southeast Asia. We forecast the region's electricity demand to increase at an average annual rate above 5% over the 2025-2027 outlook period, supported by strong economic growth.

Year-on-year change in electricity generation in Southeast Asia, 2019-2027



Notes: Other non-renewables includes oil, waste and other non-renewable sources. Data for 2025-2027 are forecast values.

Coal was the largest source of power generation in 2024, accounting for 47% of the share of electricity generation. The share of coal in the electricity mix is anticipated to remain at a similar level until 2027. Gas-fired power generation rose by slightly below 5% in 2024, and we expect moderately lower growth at an annual average rate of around 4% over the 2025-2027 period. Renewable power output posted the largest increase of all sources in 2024, rising 7% y-o-y. We forecast renewable power generation to continue growing at an average annual rate of 6% in 2025-2027.

Indonesia

Electricity demand rose strongly, with coal covering the largest share of this increase, but gas and RES also posted growth

In 2024, Indonesia's electricity demand rose by an estimated 11% year-on-year, with coal-fired output up by about 10%, providing about 50% of the additional generation. A notable trend supporting coal demand is that captive coal-fired power plants are increasingly supplying electricity to expanding nickel processing facilities. Gas-fired power grew by 8% and accounted for 14% of the total mix. Renewables, including VRE technologies, post the sharpest y-o-y increase at 15%, contributing 18% to the total supply. Despite strong growth in renewables, fossil fuel-based power generation, with a 67% share of total demand, resulted in a 9% increase in total emissions, with emissions intensity reaching 804 g CO_2/kWh. Renewable generation in 2024 primarily came from hydropower, geothermal and biomass, with solar and wind combined providing less than 1% of total output. Nevertheless, solar use saw significant progress, rising by an estimated 64% y-o-y, though making up only less than 1% of the country's electricity generation.

Projections for 2025-2027 indicate an average demand increase of 7% annually, supported by strong economic growth expectations. Renewables are forecast to grow by 8% per year over this period, while coal- and gas-fired generation are anticipated to grow at approximately 6% and 9%, respectively, maintaining their share in Indonesia's energy mix.

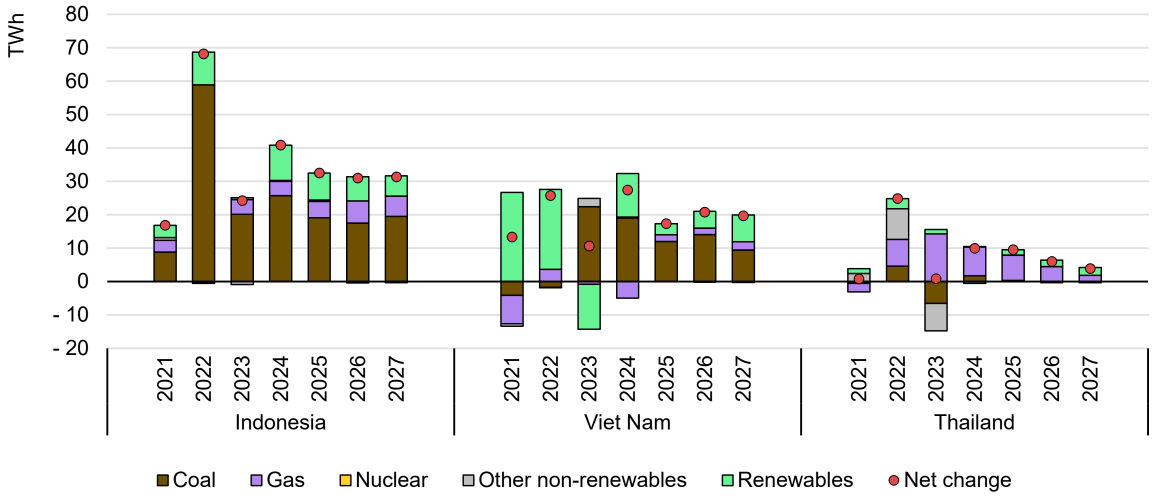
Policy changes aim to increase new investment in renewable energy projects

In Indonesia, the latest policy changes in are designed to attract more foreign investments in electricity infrastructure projects, particularly for renewable energy, by adjusting its local content requirements for solar projects in 2024. Ministry of Energy and Mineral Resources (MEMR) Decree 191/2024 relaxed the minimum local content requirement to 20% for solar projects, a reduction from previous levels set by the Ministry of Industry Regulation 5/2017. Furthermore, MEMR Regulation 11/2024 extended these changes to other renewable types, including wind and biomass, establishing a lower 15% local content requirement for wind projects. Local content exemptions were also introduced for projects financed by international loans or grants, such as those from the Asian Development Bank, World Bank and the Japan International Cooperation Agency (JICA), provided that over 50% of funding originates from development banks.

Significant infrastructure projects underscore Indonesia's ambitions in renewable energy. The launch of a 192 MW floating solar project at Cirata Dam established it as the largest in Southeast Asia and the third largest globally. Additionally, the Just Energy Transition Partnership (JETP) Secretariat conducted a kick-off meeting in May 2024 to study captive power in Indonesia, aiming to support an updated Comprehensive Investment and Policy Plan (CIPP) that incorporates off-grid industrial demand. The updated CIPP report, anticipated in early 2025, will outline a path for Indonesia's energy transition that matches their growing ambition.

Carbon management efforts also advanced since 2023 with the establishment of the country's carbon exchange and carbon capture agreements with ExxonMobil. Regional energy co-operation received a boost as Indonesia and Singapore signed a MoU for the export of 3.4 GW of clean energy, with Singapore permitting five entities to import 2 GW of low-carbon energy, including contributions from Indonesian firms.

Year-on-year change in electricity generation in Indonesia, Viet Nam, and Thailand, 2021-2027



Notes: Other non-renewables includes oil, waste and other non-renewable sources. Data for 2025-2027 are forecast values.

Viet Nam

Share of coal in electricity output rose rapidly, from 41% in 2022 to 49% in 2024, and is expected to exceed 50% by 2027

Viet Nam's electricity demand grew by almost 10% y-o-y in 2024, with the increase predominantly met by coal-fired power generation. Coal-fired generation jumped 14% y-o-y, with its share in total generation inching up to 49%, versus 47% in 2023. By contrast, gas-fired power generation declined by more than 15%, accounting for 8% of the generation mix in 2024, down from 10% the prior year. Generation from renewable sources rose 11%, reversing last year's decline of 10%, and raising its share by one percentage point to 43%. The resulting electricity mix led to a more than 10% y-o-y increase in total emissions in 2024, with emissions intensity estimated to be 595 g CO_2/kWh.

Electricity demand is projected to continue its upward trend, growing at approximately 6% per year from 2025 to 2027, consistent with the country's economic growth forecasts. Gas- and coal-fired power generation are expected to increase by an annual average rate of 8% and 7%, respectively, during the 2025-2027 outlook period. In 2027, Viet Nam's power generation is projected to derive primarily from fossil fuel sources, making up almost 60% of the total. Renewable energy is anticipated to expand at an annual average rate of 4% over this period, with its share in the total supply mix actually contracting to 40% in 2027 compared to 43% in 2024.

The Resource Mobilisation Plan, published in November 2023, under Viet Nam's JETP, outlines an ambitious pathway for renewable energy, targeting a 47% share by 2030, including substantial contributions from wind, solar and hydropower, contingent on international financial support. This plan, which is aligned with Viet Nam's net zero emissions goal for 2050, mandates no new coal-fired power plant developments after 2030. Additionally, it emphasises the advancement of technologies for battery energy storage systems, pumped-storage hydroelectricity, and thermal storage to support grid stability.

Thailand

Reliance on gas-fired power generation in Thailand will continue despite the growth of renewable energy sources

Thailand's electricity demand rose by 4% y-o-y in 2024, and is forecast to rise by 3% annually from 2025 to 2027. This projected growth is double the average annual rate of 1.5% between 2018 and 2024. The increase in electricity demand from 2025 to 2027 will be met primarily through renewable and gas-fired power generation.

Gas and coal were the predominant sources of electricity generation in Thailand in 2024, accounting for 65% and 17%, respectively. Gas generation is expected to rise at an average annual rate of 3% from 2025 to 2027, maintaining its 65% share in the electricity mix. Meanwhile, coal generation is forecast to remain relatively stable, with an annual average increase of under 1% from 2025 to 2027, accounting for about 16% of the electricity generation mix.

Renewable energy provided 16% of power generation in 2024, with bioenergy the leading source, accounting for more than 50% of the total, while VRE made up 27%. In the short term, solar PV is expected to be a key driver among VRE sources, with an average annual growth rate of 15% between 2025 to 2027. However, bioenergy will continue to be the dominant source in 2027, still contributing more than 50% of total renewable electricity output.

Thailand announced its draft Power Development Plan in July 2024, marking a significant shift in the country's energy strategy. By 2037, Thailand aims to reduce its dependence on gas and coal to 41% and 7%, respectively. Yet, the draft gas management plan for 2024 suggests imported gas could rise from 33% in 2024 to 43% by 2037, potentially increasing exposure to price volatility risks.

To advance renewable integration, the draft PDP 2024 has set a target to source 51% of its energy from renewables by 2037. Supporting this effort, the country is introducing power purchase agreements (PPAs), which will allow private companies – particularly in energy-intensive industries – to procure up to 2 GW directly from renewable producers. Furthermore, an additional 3.67 GW is allocated for renewable PPA feed-in-tariff (FiT), including 2 632 MW for solar and 1 000 MW for wind. Looking to diversify further, the draft PDP 2024 envisages adding 600 MW of SMRs and starting 5% hydrogen blending in gas power plants by 2030.

Malaysia

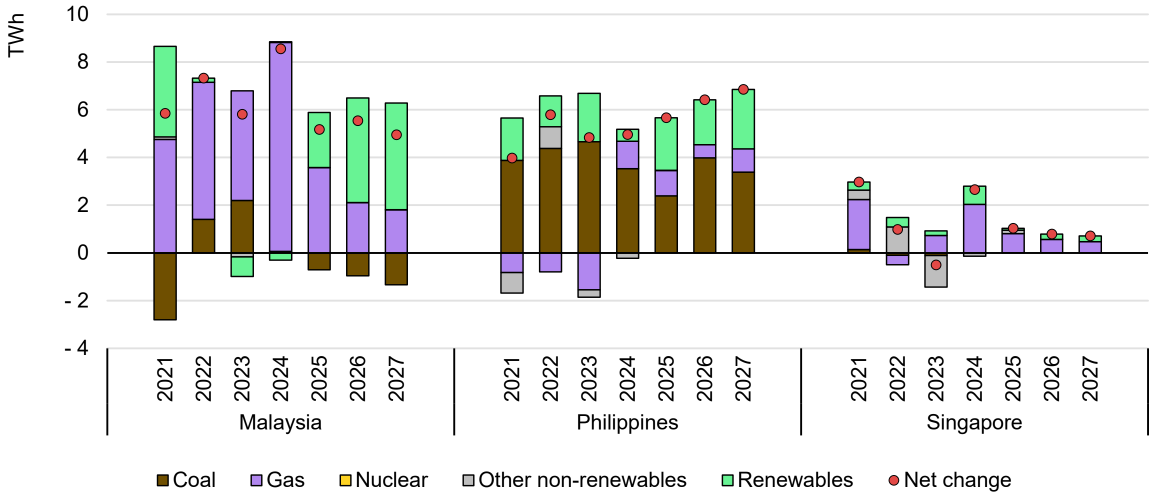
Share of renewable energies in electricity generation is forecast to reach the 20% mark by 2027, up from 17% in 2024

Electricity demand rose by more than 5% in 2024, and is expected to grow by 3% annually out to 2027, supported by increasing levels of economic activity and space cooling. Coal-fired generation was largely unchanged in 2024 and is forecast to contract by an annual average of 1% over the 2025-2027 period. Gas-fired generation rose by an estimated 1% in 2024, but growth is expected to moderate to 3% on average in 2025-2027. Renewable generation fell slightly by 1% but is set to rebound sharply in 2025, rising by 7%, and by an average 10% in 2025-2027. Among renewables, solar PV growth is expected to continue at a strong pace with an annual average rate at just above 20% to 2027.

The electricity mix was dominated by coal and gas in 2024, with shares of 45% and 38%, respectively. We expect the share of gas-fired generation to remain stable while coal-fired generation is forecast to decline to 40% in 2027. Renewable power generation's share is projected to rise from 17% in 2024 to 21% in 2027. This change in the electricity mix is set to deliver a reduction in the emission intensity, with an average annual decrease of 2.6% during 2025-2027.

Malaysia's 2023 National Energy Transition Roadmap (NETR) puts a strong focus on reducing its reliance on fossil fuels and on accelerating the energy transition, with ambitious targets for renewable energy, energy efficiency, carbon capture, utilisation and storage (CCUS), and alternative fuels. Malaysia has set a bold goal of reaching 70% renewable energy in the power capacity mix by 2050.

Year-on-year change in electricity generation in Malaysia, Philippines, and Singapore, 2021-2027



Notes: Other non-renewables includes oil, waste and other non-renewable sources. Data for 2025-2027 are forecast values.

Philippines

Renewables are expected to meet more than one-third of additional electricity demand growth over the next three years

Electricity demand in the Philippines rose by 5% in 2024, and we expect average annual growth of over 5% in the 2025-2027 period. The increase in demand is broadly in line with GDP growth expectations, with economic activity anticipated to be a key driver of electricity consumption over the forecasting period.

Overall, growth of coal generation moderates to 4% in 2025-2027, down from 7% in 2018-2024. Despite the coal moratorium, the Philippines remains dependent on coal, which account for 62% of the electricity generation mix in 2024, and is expected to only marginally decrease to 60% by 2027. The Department of Energy has stated that any approved coal projects prior to the 2020 coal moratorium will be maintained, so the effects of this policy will be seen in the medium to long term. We expect gas-fired power generation to maintain its current share of the electricity mix of 14% from 2025 to 2027. The share of renewable power generation to increase slightly, from 22% in 2024 to 24% in 2027.

Hydropower saw a decline of about 3% in 2024, as a combination of high temperatures and reduced rainfall caused drought conditions in much of the country. However, we assume a return to growth for hydropower generation to an average 3% annually over the 2025-2027 forecast period. Solar PV generation rose rapidly in 2024, up 35% y-o-y. This strong growth is forecast to continue over the 2025-2027 period, supported by government policies but also bolstered by the low cost of PV modules, with an average annual increase of 29%. Similarly, wind generation saw growth of 21% y-o-y in 2024, and we forecast a slightly stronger increase of 24% on average over the outlook period.

The Philippines continues to support increasing renewable energy capacity, with a particular focus on solar energy. The Department of Energy announced that the next green energy auction, eventually moved to February 2025, would include an auction on energy storage and integrated renewable energy and energy storage systems (IRESS) aimed at supporting overall variable renewable energy development. Policies like the Green Energy Auction Program and Renewable Portfolio Standards, implemented by the Department of Energy to support clean energy developments, continue to help attract investments for renewables.

Singapore

Targets for low-carbon electricity imports were raised, with power integration plans to double import capacity

Singapore's electricity demand rebounded by around 4.5% in 2024, following a 1% decline in 2023. We expect growth to average 1.5% a year in 2025-2027, driven largely by advanced manufacturing, the digital economy and the transport sector.

Natural gas continued to dominate Singapore's energy mix in 2024, accounting for 93% total power generation. However, this share is expected to slightly decrease in the coming years as renewable energy sources, mainly solar PV and biomass, increase. Renewable generation is forecast to rise by an average 6% annually in 2025-2027.

In April 2024, the Energy Market Authority (EMA) awarded a contract for two power generating units that will provide 100 MW of fast start (FS) generation capacity by Q2 2025 to ensure stable power supply in the event of a disruption. To further increase system stability, two 340 MW OCGT units are being constructed and expected to be operational in 2025.

Singapore announced that they are raising their targets for low-emissions electricity imports from 4 GW to 6 GW by 2035. In 2024, multiple electricity import plans made substantive progress, with five Indonesia-based projects awarded conditional licences for a total of Electricity imports are expected to make up around one-third of Singapore's energy needs by 2035. In May 2024, Singapore, Cambodia and Lao People's Democratic Republic (Lao PDR) formed a working group to facilitate cross-border electricity trade as part of the ASEAN Power Grid vision, including exploring frameworks for commercial arrangements and the development of generation and transmission infrastructure.

Singapore will double its power import capacity with the second phase of the Lao PDR-Thailand-Malaysia-Singapore Power Integration Project (LTMS-PIP). Under this new phase, the volume of electricity traded will rise from 100 MW to a maximum of 200 MW. The expansion was made possible by new multi-directional power trade, under which additional supply will come from Malaysia.

According to plans from SunCable, up to 1.75 GW of low-carbon electricity import capacity from Australia could become operational in 2035, following the EMA's conditional approval for the project this year. The imported electricity will be generated from solar power in Australia's Northern Territory and transported via approximately 4 300 km of newly installed subsea cables. If the project is successfully implemented, it would represent almost 10% of Singapore's electricity imports.

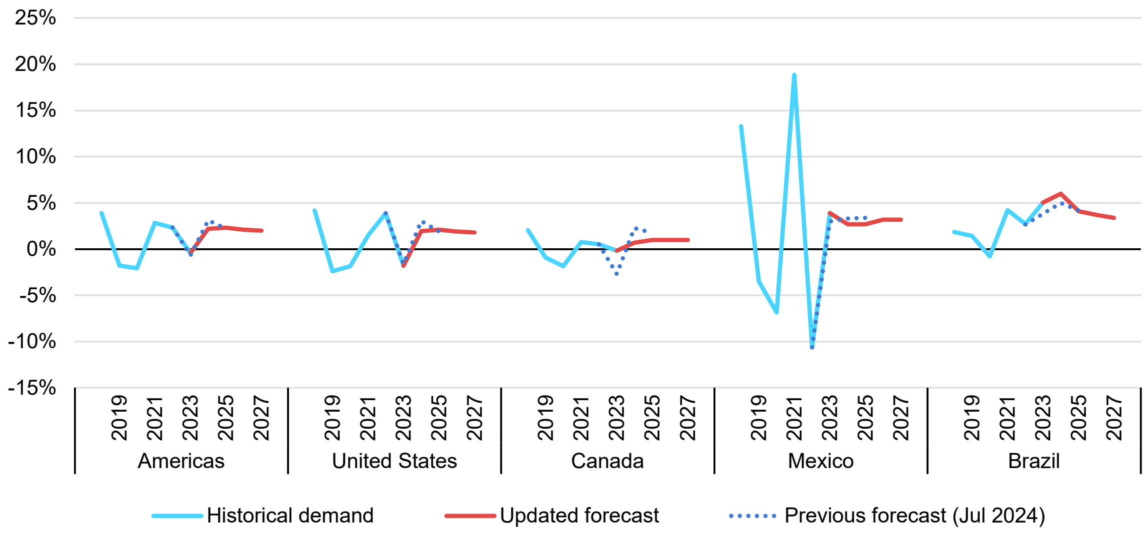
Americas

Growth in renewable power generation replacing fossil fuel sources

Electricity demand in the Americas returned to growth in 2024, rising by 2.2% following a modest decline of 0.4% the previous year. The rebound in demand was led by the United States (+2%), Brazil (+6%) and Canada (+0.7%), which are the three largest electricity consumers in the region and together account for just over 85% of the market share.

We forecast electricity demand in the Americas region will continue growing at an average annual rate of about 2.2% in 2025-2027. The United States, the world's second largest electricity consumer after China, will account for nearly 60% of the growth over the outlook period, with the continued expansion of data centres a key driver, followed by industry. Economic growth coupled with increased manufacturing activity also supported higher electricity demand in 2024. Emerging industries such as electric battery and solar panel production are expected to further boost electricity demand during our forecast period. Brazil, which represents 10% of the region's market share, will account almost 20% of the growth to 2027, with wind and solar providing for all the additional demand, while hydropower remains the mainstay of the country's electricity supply.

Year-on-year percent change in electricity demand, Americas, 2018-2027



Note: Data for 2025-2027 are forecast values. The years on the x-axis start at 2018.

Renewable power generation grew by over 4% in 2024 across the Americas, primarily due to growth in solar PV and wind of almost 30% and 8%, respectively. Solar PV will be a key driver of increased renewable generation, and we forecast an average annual growth rate of 20% during 2025-2027. Wind is also projected to play a significant role, up on average by 9% annually over the outlook period. Renewables, the primary source of electricity generation in the region, will see its share rise from 37% in 2024 to 43% by 2027. Hydropower will continue to account for about 20% of total electricity generation in the Americas over the outlook period.

Coal-fired generation declined by about 3.5% in 2024 and we expect this contraction to continue at a similar rate during 2025-2027. Gas-fired generation rose by nearly 4.5% and is expected to record a slight decline with an average rate of about 1% in the 2025-2027 period. The decrease in coal-fired electricity coupled with strong growth in renewables led to a reduction in the emission intensity in power generation of 2% in 2024 for the region, and we expect a continued decline at an average annual rate of around 4.5% in 2025-2027.

United States

Demand growth resumes on data centre expansion and robust manufacturing activity

Electricity demand in the United States recovered to growth of 2% after contracting in 2023 due to milder weather. A key contributor to higher demand is the expansion of data centres, which account for a growing proportion of the country's electricity consumption. Manufacturing activity rebounded on a stronger economy in 2024, after dipping in 2023. Record-high system peaks were observed by the Texas independent system operator ERCOT and the Western Interconnection (which includes US states as well as British Colombia and Alberta), as heatwaves significantly increased electricity usage. Weather events have caused increasing amounts of power outages and continue to impact systems, with major hurricanes Helene and Milton resulting in 4.7 million and 3.4 million customers, respectively, losing power.

From 2025 to 2027, we expect electricity demand to grow by an average annual rate of around 2%.[26] Data centres drive the increases in the commercial sector. New manufacturing capacity, especially from additional facilities for the development of batteries and semiconductor chips, is expected to further create additional demand growth. Continued electrification of the transportation and

[26] The forecast is made based on the policy framework as of December 2024.

building sectors will further support strong growth. (See Demand, *Electricity demand in the United States rebounds to new record in 2024*).

Total renewable generation increased in 2024 despite reduced hydropower output due to droughts

Renewable power generation rose by about 8% in 2024, led by strong growth in solar and wind. Solar PV saw the largest gain, up 30% y-o-y, thanks to the expansion of utility-scale capacity from 2023. Texas and California, the two biggest markets for solar PV in the United States, particularly saw strong growth in total solar PV generation. US wind power generation was up by more than 6%. By contrast, hydropower output continued to be impacted by drought conditions in 2024, particularly in the Pacific Northwest, which hosts the majority of US hydro capacity. Hydropower generation in the United States decreased by around 1% y-o-y, reaching its lowest level in over two decades. However, we see an improved outlook in our 2025-2027 period, with total renewable generation projected to grow at an average 10% annually.

Gas-fired generation rose by 3.7% y-o-y in 2024, a slower rate compared to the average growth rate of 6.7% recorded during 2022-2023, despite lower prices. Natural gas spot prices hit an all-time low of USD 1.49/Btu at Henry Hub in March 2024 due to both high production and inventories, coupled with low consumption. Out to 2027, gas-fired output is forecast to decline slightly, at an average annual rate of around 1%. Coal-fired generation fell 3.7% in 2024 y-o-y and accounted for 16% of total generation in the country. Coal retirements continued into 2024, with about 3 GW of coal-fired capacity decommissioned. Coal-fired generation is expected to decline at an average annual rate of around 2% in 2025-2027.

Nuclear energy is receiving strong interest, with momentum from policies and innovation building up

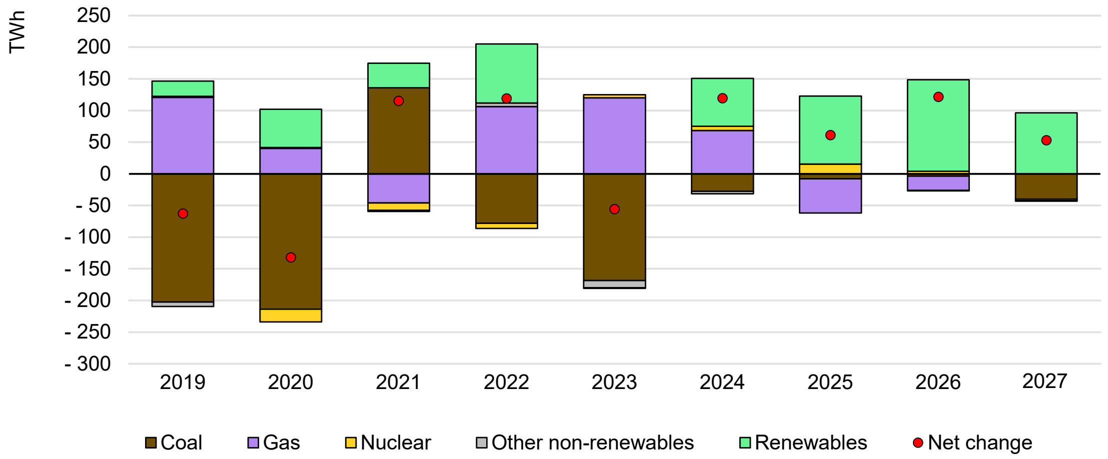
Nuclear generation increased by almost 1% y-o-y in 2024, following the first new nuclear project in the United States in over three decades commenced operations. Vogtle Unit 4 entered commercial operation in April 2024, which followed Unit 3 that came online in 2023. As a result, nuclear generation is forecast to rise by 2% in 2025, but thereafter will remain stable out to 2027.

Just beyond our outlook period, Constellation plans to restart the Three Mile Island nuclear plant after signing a 20-year power supply contract with Microsoft in September 2024, highlighting demand for nuclear power from the technology sector as they ramp up data centres to support artificial intelligence. The company expects the Unit 1 reactor at Three Mile Island in Pennsylvania to come back online in 2028, subject to approval by the Nuclear Regulatory Commission. It also plans to extend the plant's operations to at least 2054.

Data centres are already the largest contributor to US electricity demand growth and a growing number of technology companies are planning to secure their electricity supplies from a dedicated source of nuclear energy. Small modular reactors (SMRs) are particularly receiving increasing attention. Plans to build up to 25 GW of SMR capacity associated with supplying data centres have been announced globally, almost all of them in the United States.

The United States is a global leader in SMR innovation, with the federal government supporting the development of multiple designs. In addition, the Fire Grants and Safety Act included the ADVANCE Act, which is aimed at revitalising the nuclear power sector. The United States has the largest fleet of nuclear reactors in the world, and the share of nuclear in in power generation is currently just under 20%. The Act reduces certain fees and assigns additional staff for licensing reviews, while also including provisions that will fast track the deployment of microreactors and the development of nuclear plants on former coal sites.

Year-on-year change in electricity generation in the United States, 2019-2027



Notes: Other non-renewables includes oil, waste and other non-renewable sources. Data for 2025-2027 are forecast values.

Canada

Electricity demand growth returns as coal declines and hydropower contends with drought conditions

In 2024, Canada's electricity demand rose by 0.7%, after declining slightly in 2023, as a hot summer was offset by a warm winter. We expect demand to increase at a similar rate of 1% per year through the 2025-2027 forecast period. Data centres are projected to be a significant driver of growth, with both the Energy Regulator and utilities anticipating greater demand from these facilities. Data centre development is either underway or planned, especially in Toronto and Montreal.

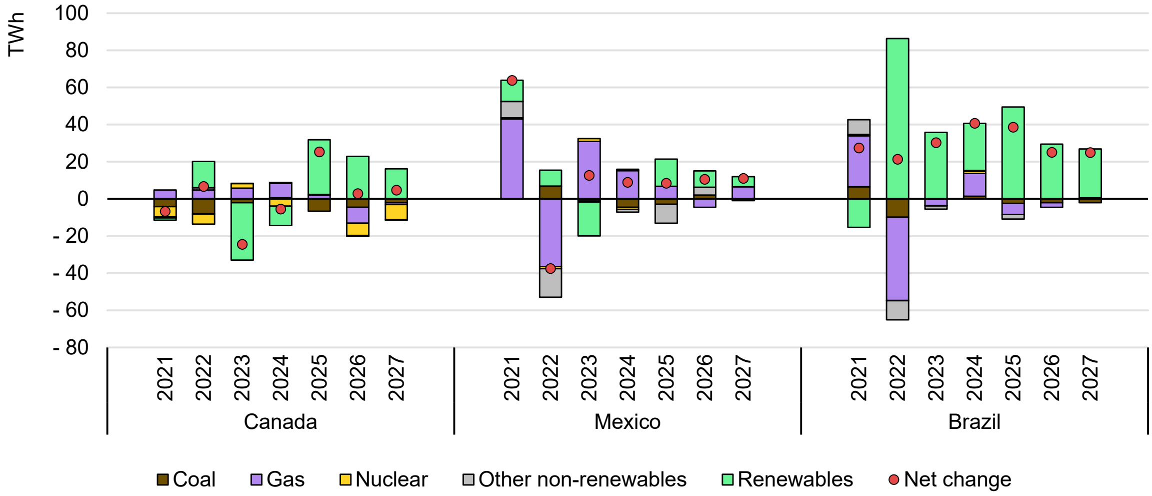
Coal-fired power generation is estimated to have increased slightly in 2024 but is projected to decline in our forecast, with output roughly halved by 2027, in line with Canada's commitment to phase out coal power by 2030. Gas-fired generation rose by an estimated 9% y-o-y, while nuclear generation declined by 4.4% in 2024. VRE sources continued their upward trajectory, with their share anticipated to reach 10% of total generation by 2027. In 2024, solar PV and wind recorded gains of around 45% and 18%, respectively. We forecast this growth to continue over the 2025-2027 outlook period, with annual increases averaging 6% for wind and 7% for solar PV.

Hydropower output – the dominant source of power generation, which accounts for around 60% of Canada's total electricity demand – dropped by 6% in 2024 due to severe drought conditions. In 2024, drought conditions in Canada resulted in the lowest recorded year for hydropower in over two decades. The decline in hydropower generation necessitated increased imports from the United States, with power imports exceeding exports to the United States for the first time in nearly a decade. Assuming a return to normal hydrological conditions, hydropower output is projected to rise through the remainder of the forecast period.

Nuclear output declined in 2024 due to maintenance at the Point Lepreau Nuclear Generating Station (660 MW) and the continued refurbishment of the Bruce Nuclear Power Station (6.2 GW), though works are ahead of schedule. The refurbishment of Darlington 1 was completed five months ahead of schedule in November 2024. Unit 4 is expected to complete refurbishment in 2026 as planned. Units 5-8 of the Pickering Station had their retirement postponed and will be refurbished instead, operating until end of 2026 before refurbishment begins. Over the 2025-2027 forecast period, we expect nuclear generation in Canada to decline on average by 3% annually.

The government released a new report, Powering Canada's Future: A Clean Electricity Strategy, detailing plans to develop a power system that provides clean, affordable and abundant electricity. The strategy focuses on growing the grid, managing demand, ensuring policy certainty, and collaboration with regions to develop specialised plans. The country's Clean Electricity Regulations were also finalised, which aim to reduce nearly 181 Mt of cumulative greenhouse gas emissions from the power generation sector between 2024 and 2050. Canada revised its target to achieving a net-zero power grid by 2050, updating the previous goal of an emission-neutral power grid by 2035.

Year-on-year change in electricity generation in Canada, Mexico, and Brazil, 2021-2027



Notes: Other non-renewables includes oil, waste and other non-renewable sources. Data for 2025-2027 are forecast values.

Mexico

Record-high electricity demand and extended droughts strained Mexico's power system in 2024

Mexico's electricity demand rose 2.7% in 2024, driven higher by economic and population growth, as well as increased industrial activity. Electricity demand is expected to grow at a steady annual rate of just 3% during 2025-2027, though political and economic uncertainties may impact this outlook.

Gas-fired power – the largest source of supply in the generation mix, exceeding 60% of the total – covered all of the additional demand. By contrast, hydropower generation continued to struggle as drought conditions persisted in 2024. Despite increasing by 9% y-o-y, this was the lowest level seen in over two decades, excluding 2023. This reduced the output from the country's large hydroelectric plants, which are critical for system flexibility and meeting peak demand. This prolonged water scarcity placed additional pressure on other generation sources and highlighted the importance of improving water resource management.

A series of [rolling outages](#) took place in May. Triggered by record-high electricity demand of nearly 50 GW – 9% higher than 2023's peak – and generation unavailability, the outages affected over 2.6 million customers nationwide. Investigations pointed to a combination of factors, including inadequate maintenance planning, infrastructure constraints, and the inability to meet surging demand with existing capacity. These events highlighted vulnerabilities in the power system and the urgent need for investment in reliability measures.

In November 2024, the Mexican government introduced a National Energy Plan (NEP), which aims to balance the roles of the state and private sector in electricity generation. The plan stipulates that the Comisión Federal de Electricidad (CFE) will maintain a minimum 54% share in new energy assets, while private sector investment is encouraged for the remaining 46%, particularly in renewable energy projects. Public-private partnerships will play a central role, with wind and solar power development prioritised to meet growing demand. To attract private investment, the government has committed to streamlining regulatory processes and addressing bureaucratic hurdles.

The plan also assures that electricity tariffs will not increase beyond inflation rates in order to maintain affordability for consumers while ensuring the financial viability of infrastructure investments. Additionally, the modernisation of transmission and distribution networks is a key focus, targeting a reduction in bottlenecks and the enhancement of grid stability. These efforts could help address longstanding challenges in Mexico's power infrastructure, including financial constraints and regulatory hurdles that have previously hindered progress.

The NEP is part of Mexico’s renewed commitment to its energy transition, with a focus on accelerating renewable energy development and modernising regulatory frameworks to support decarbonisation goals. Achieving these ambitions will require sustained effort, careful planning, and close collaboration between public and private stakeholders but will ensure a path for a reliable and sustainable energy system.

Brazil

Electricity demand in Brazil grew by a staggering 6% in 2024 amid robust economic growth and high summer temperatures

Electricity demand grew by 6% supported by robust economic growth. Higher-than-normal summer temperatures also boosted demand due to more intense use of air conditioning.

Electricity demand is anticipated to grow at around 3.7% annually from 2025 to 2027. In addition, the Luz Para Todos programme, or Light for All, which aims to combat energy poverty and enhance quality of life in rural and Legal Amazon areas by providing access to clean, renewable energy for electricity generation, is projected to support increased residential electricity consumption. In 2024, the programme received the largest investment funds since its creation in 2003, and the goal for the coming years is to serve the 318 000 families that are still without electricity.

On the supply side, from 2024 onwards, Brazil's electricity market is marked by substantial growth rates in renewable energy, particularly in solar and wind, while fossil fuel sources continue their steady decline. Renewables rose 4% in 2024 and are expected to post annual average gains of 5.1% over our outlook period. Wind power generation grew by 13% in 2024, and it is forecast to increase by an average rate of around 8% per year until 2027. Solar PV rose at the fastest rate of all sources, up 46% in 2024, and we expect an average yearly growth rate of 22% from 2025 to 2027. Despite a 2.8% decline in 2024, hydropower generation remains the largest source of power. In 2025, we assume hydropower to return to 2022 levels, though a slight increase is projected for the remainder of the outlook period. These trends underscore Brazil’s accelerated shift towards renewable energy sources, whose share in the total electricity generated will be, depending on hydrological conditions, about 90% by 2027, compared to 88% in 2024 and 78% in 2017. As a result, emission intensity will fall on average by 13% annually over the 2025-2027 period.

The rapid growth of variable renewable generation has led to frequent curtailments. To address the issue, Brazil held two transmission auctions (001/2024 and 002/2024) with three lots totalling 7 250 km in transmission lines, 19 200 megavolt-amperes (MVA) in transformation capacity for substations and investments of USD 4 billion. Additional regulatory measures that help balance supply with demand are under consideration in draft Bill 414/2021. Furthermore, discussions are ongoing in Public Consultation 45/2019 to improve the rules governing the prioritisation of generation curtailment by the system operator, aiming to mitigate both the technical and economic impacts on generators and electricity consumers.

Finally, Brazil faced the worst drought in its history in 2024, and although it was severe by historical standards, it was not as strong in the most important hydrological basins of the National Interconnected System (SIN). The energy system showed resiliency by planning for a reduction in hydroelectric supply during the drought. As hydropower reservoirs reached low levels, the country relied on thermal power plants, which led Brazil’s regulatory agency ANEEL to trigger an additional tariff (red flag tariff, level 1), resulting in a charge of USD 0.75 for every 100 kWh.

Progress is being made to open power markets to competition

To support plans to gradually open the power market to competition, the Ministry of Mines and Energy (MME) has issued Ordinance 50/2022, which enabled high-voltage consumers to access the free energy market. Beginning in January 2024, Group A customers – including small and medium-sized businesses such as supermarkets, bakeries, pharmacies, retail chains, and hotels – began migrating to this market. This transition allows consumers to select their energy suppliers and negotiate customised contracts, boosting competition within the sector. In 2024, the number of consumers in the Free Energy Market expanded by approximately 50%, highlighting the importance of a law project on power sector reform (Bill 414/2021). The proposed bill, currently under review in the National Congress, aims to reform Brazil's electricity sector regulatory framework to foster greater competition among energy providers. If approved, it would allow all consumers, regardless of size, to access the Free Energy Market.

Other Americas

Chile

In 2024, electricity demand grew by around 2.5% y-o-y, in line with economic growth. Annual hydropower generation rose by 14% y-o-y, reaching its highest level since 2006, as rainfall was particularly heavy in the central and southern areas during May and June. Strong hydropower output, together with the increased contributions from wind and solar PV, led the total share of renewables in the generation mix to reach almost 70%. By 2027, wind and solar PV combined are forecast to account for more than half of Chile's electricity generation, up from 32% in 2024, with solar PV the largest source in the electricity mix. The CO_2 emission intensity of power generation is set to halve between 2024 and 2027. Solar PV and wind combined would meet all new demand, which is set to grow by 2.2% per year on average in 2025-2027.

In August 2024, a strong storm caused large power outages in Chile's central and southern regions, mainly affecting the Santiago Metropolitan Region. In early August, severe storms hit the country, with wind speeds in Santiago exceeding 120 km/h – significantly higher than the previous record of 76 km/h. The storms damaged electricity networks, leading to outages that simultaneously affected nearly a million consumers nationally and more than 600 000 in the Santiago Metropolitan Region, which houses nearly half of the country's population. The prolonged outage, which lasted for more than a week for at least 60 000 customers, affected essential services and led to public demonstrations in various communes, highlighting the societal impact of outages and the need for resilient infrastructure.

Another key development in Chile's electricity sector in 2024 relates to regulated electricity tariffs. After having frozen electricity tariffs paid by end-users under regulated prices since late 2019, Chile began gradually normalising them in 2024, with accompanying subsidies to mitigate the impact on consumers. In April 2024, the Tariff Stabilisation Law was enacted to align tariffs with real costs, as frozen rates were about 30% below actual costs due to outdated exchange rates and unaccounted for increases in fuel prices and inflation. This measure was deemed essential, as frozen tariffs had created debt for power companies that amounted to more than USD 6 billion. The first increase came in June 2024 with the unfreezing of distribution network charges, raising bills by an average of 7%, followed by a 12% rise in July from transmission and generation charges. To repay the debt, a specific CLP 22/kWh (Chilean peso) charge was introduced in July 2024 for customers over 350 kWh/month, which will be reduced to CLP 9/kWh in 2027-2035. A temporary subsidy was also implemented to support more than 1.5 million households through 2026, with plans under discussion to expand its coverage to 4.7 million and to extend it to 2027.

Colombia

In 2024, electricity demand in Colombia declined by approximately 3% y-o-y. As forecasted by national authorities and weather organisations, the El Niño Southern Oscillation significantly affected rainfall and temperatures from October 2023 to April 2024, but the drought also persisted after the end of the phenomenon. This resulted in particularly low hydropower generation during this period. Hydropower on average, provided 70% of the country's electricity over 2017-2023, but was unable to meet its usual share in the electricity mix in 2024. Simultaneously, rising temperatures across the nation led to a significant increase in electricity demand, particularly for cooling.

Low hydro output resulted in higher generation from thermal power plants (mainly coal- and gas-fired) throughout the year, particularly in April as generation averaged 65 GWh per day – four times the output from the same month the previous year. Meanwhile, hydropower generation plummeted by 40%, reducing its share of the electricity mix to slightly below 50%, its lowest level since March 2016. Emergency measures from the government included water rationing as well as several restrictions and halts in exports to Ecuador, which led to electricity rationing in the neighbouring country. The latest halt order started on 30 September and was expected to be valid until end of July 2025. However, increased rainfall in November led to a restart in Colombian exports to Ecuador, a country which relies on electricity imports, and has suffered extensive outages during 2024.

With Colombia's only LNG terminal working at full capacity in critical periods, these episodes of low hydro generation, high electricity demand and declining domestic gas production, coupled with limited coal-fired capacity, raised concerns about a potential power supply-demand gap of 4-5 TWh by 2027-2028. The recent crisis also impacted retail prices for households, which have increased by 70% between January 2020 and August 2024.

Colombia has launched a USD 40 billion investment plan over the decade to accelerate its energy transition. This includes expanding solar and wind capacity, converting thermal plants, promoting electric vehicles and developing energy communities. The rapid increase in VRE capacity in 2024 reflects this commitment, as it surged from 500 MW in December 2023 to nearly 2 GW by the end of 2024, driven mostly by solar PV. This is part of the government's broader plan to reach 6 GW of VRE capacity to 15% of the electricity mix by 2026, with further expansion planned through 2032 (17 GW of solar PV, 4 GW of wind).

Costa Rica

Costa Rica also faced significant challenges in the early months of 2024 due to the El Niño phenomenon, which negatively impacted reservoir levels and hydropower. Between January and May 2024, hydropower accounted for only about 50% of the electricity mix. To compensate, thermal power plants running on imported fuel oil and diesel provided crucial backup, making up 20% of the electricity mix during the first five months of the year. These plants covered less than 2% of the total generation during years 2021 and 2022 but had already surpassed 9% in 2024. Despite the government preparing an electricity rationing plan in May, it was never activated as rains quickly restored reservoir levels.

The country's electricity demand grew by 1.3% y-o-y in 2024. This increase was largely due to higher air conditioning usage in the residential and commercial sectors, along with new urban developments. Future demand could see further growth with potential expansions in the semiconductor industry. Electricity demand is forecast to rise at an average annual rate of just under 1% during the 2025-2027 forecast period.

Politically, Costa Rica has seen discussions on a proposed law (Ley de Armonización del Sistema Eléctrico Nacional) to open the electricity generation market to greater competition, as privately-owned renewable capacity is currently capped at 15%. If enacted, this law could pave the way for much needed private sector participation in the energy sector. National authorities are actively encouraging private sector investment in EV charging infrastructure as Costa Rica anticipates having a fleet of more than 150 000 electric vehicles by 2030. This growing fleet is estimated to require around 290 GWh of electricity annually, accounting for approximately 2% of the country's total yearly demand.

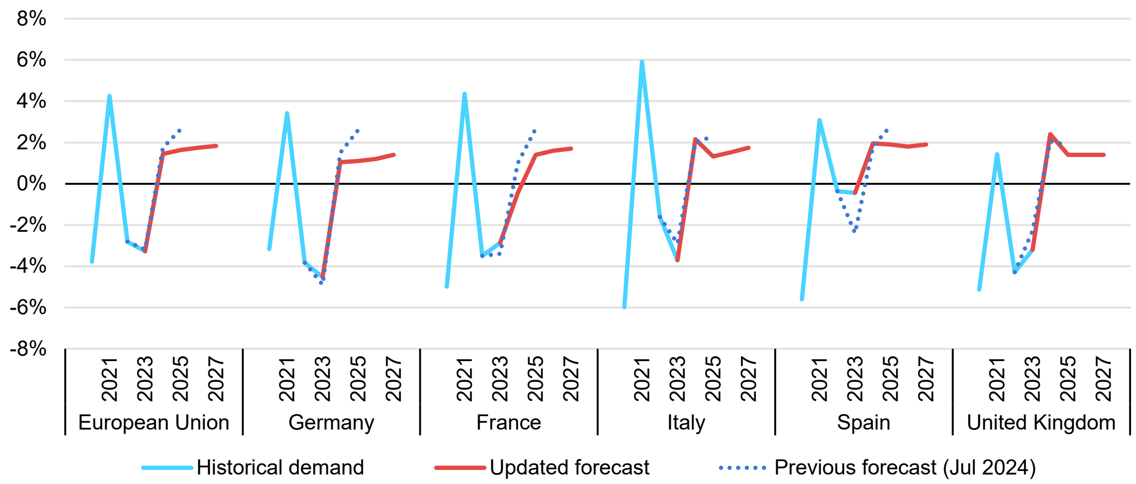
Europe

Demand growth varied among countries due to weather impact and economic conditions

Electricity demand increased by 1.9% y-o-y in 2024, after two years of contractions. Electrification of the heating and transport sectors progressed and data centres continued to expand in the region, while the industrial sector in the European Union stabilised and was relatively flat. Weather also had a marked impact on higher demand in some countries. One-quarter of the growth in total electricity demand in Europe in 2024 came from Türkiye alone, amid strong 4% growth on increased space cooling due to heatwaves. For Europe, we expect demand growth to continue at 2024 growth levels, at about 1.9% annually in 2025-2027, assuming industrial activity continues recovering while electrification gathers pace.

Even as the region's electricity demand recovered, coal- and gas-fired generation both declined, by 11% and 8%, respectively. By contrast, renewable power generation rose significantly, by 7% in 2024, displacing gas and coal. We expect growth in renewable generation to continue at a similar pace over the 2025-2027 period, at an average annual rate of approximately 7%. Solar PV and wind power generation will provide much of the increase over the outlook period, with annual growth of around 17% and 10%, respectively. This shift away from fossil fuel power generation in 2024 contributed to a reduction in CO_2 emission intensity of 12% in Europe and is forecast to average an annual decline of 9% in 2025-2027.

Year-on-year percent change in electricity demand in Europe, 2020-2027



Note: Data for 2025-2027 are forecast values. The years on the x-axis start at 2020.

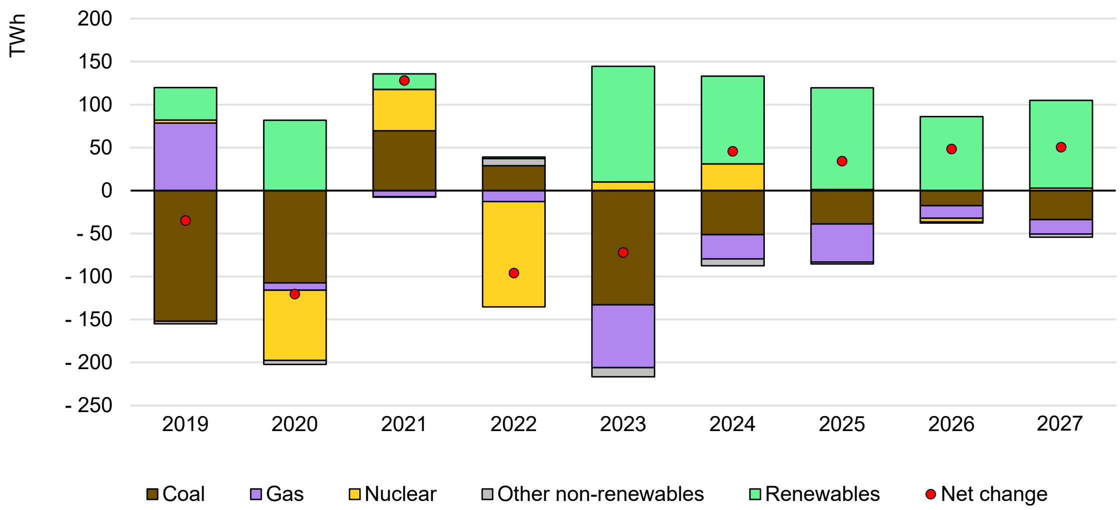
European Union

Electricity demand returns to growth, with renewables more than covering the increase and displacing fossil fuel sources

Electricity demand in the European Union rose by 1.4% y-o-y in 2024 after a weak economic landscape led to two consecutive years of decline. Demand is still below that in 2021 and is not anticipated to reach similar levels until at least 2027. We forecast an average annual growth of 1.7% over the 2025-2027 outlook period.

In 2024, renewable generation rose by 8.4% and this growth trend is expected to continue in the 2025-2027 outlook period, albeit at a slightly lower annual average of 7.2%, which will more than replace fossil-fuel sources and cover additional electricity demand. Solar PV generation marked a milestone in 2024, surpassing coal-fired output. Coal-fired generation was down by about 15% in 2024, and we forecast the decline will continue over the outlook period, but at a slower rate of approximately 11% per year. Gas-fired power decreased by 6% in 2024, with an average yearly decline of 6% forecast for 2025-2027. Nuclear power rose by 5% in 2024, with output to remain stable over the outlook period. The share of renewables in the power supply is forecast to grow from 48% in 2024 to 56% in 2027.

Year-on-year change in electricity generation in the European Union, 2019-2027



Notes: Other non-renewables includes oil, waste and other non-renewable sources. Data for 2025-2027 are forecast values.

The Green Industrial Plan initiatives support raw material acquisition, net-zero industries and electricity market reform

The Green Industrial Plan introduced by the European Commission (EC) in 2023 aims to implement measures to support Europe's net-zero industry through the scaling up of the EU's manufacturing capacity for green technology. The EC proposed three measures to improve the regulatory environment and ensure that the European Union has secure access to the raw materials necessary for industry to build net-zero technologies, a regulatory environment that allows for the scale-up and deployment of these technologies and an electricity market design that protects consumers while allowing them to benefit from the increasing share of low-cost renewables.

Firstly, the Critical Raw Materials Act (CRMA) provides a framework to strengthen the supply chain of critical raw materials. The European Union continued to enter into strategic partnerships on sustainable raw material supply chains in 2024, bringing the total number of agreements to 14. These agreements ensure the European Union has a variety of suppliers of critical raw materials in line with achieving their goal of no more than 65% of annual consumption of a raw material coming from a single country.

Secondly, the Net-Zero Industry Act (NZIA) also came into force in 2024, and targets the build-up of manufacturing capacity so that at least 40% of the EU's net-zero deployment needs are met by domestic production by 2030. The NZIA allows national priority status for net-zero projects, with benefits that include faster administrative responses, permitting and prioritisation in judicial issues and disputes. The act also proposes that the European Union develop yearly storage capacity for at least 50 Mt CO_2 for hard-to-abate emissions by 2030. The EC set out the Industrial Carbon Management Strategy detailing the necessary steps to establish a union market for CO_2 services by 2030.

Finally, measures were adopted for reforming and improving electricity market design. These reforms are intended to provide derisking and price stability through state-backed two-way contracts for difference (CfD) for new investments in select forms of power generation. The reforms also promote stability through power purchase agreements (PPAs), which are a contract between a producer and a buyer at mutually agreed rates over a long-term period. The electricity market design reforms also include mechanisms for a future crisis such as empowering the European Council to declare a crisis if prices increase significantly and allowing member states to take measures to protect disadvantaged consumers.

Furthermore, electricity market design reform aims to increase the uptake of non-fossil fuel flexibility through national Flexibility Needs Assessments, which, using an EU-wide methodology that is being developed, identify flexibility needs. These assessments also aim to provide additional capacity support for non-fossil fuel flexibility, support national flexibility measures based on assessed needs, and ensure the integration of renewables while maintaining grid stability. The reform enhances consumer protection by ensuring consumers have the right to choose suppliers, access dynamic pricing, and fixed-term contracts, while introducing stricter rules for suppliers to shield customers from wholesale market volatility. Vulnerable customers are to be protected from disconnections by 'supplier of last resort' systems if they did not exist already.

The European Commission plans to follow with a Clean Industrial Deal in 2025, building upon the European Green Deal to boost EU industrial competitiveness and decarbonisation. Related aspects include the Industrial Decarbonisation Accelerator Act, new state aid frameworks, clean trade and investment partnerships, revision of public procurement rules, action plans for affordable energy, the Circular Economy Act, strengthening grid infrastructure, a sustainable transport investment plan and measures against carbon leakage.

The EU-ETS was expanded and the CBAM continues to phase-in changes

Since January 2024, the EU Emissions Trading System (EU-ETS) has been extended to cover the GHG emissions from maritime transport. To account for these additional emissions, the EU-ETS emissions allowance cap rose by 78.4 million European Union Allowances (EUAs), each representing the right to emit one tonne of CO_2-eq. This brought the total union-wide cap to 1 386 051 745 EUAs for 2024. The EU-wide cap on emissions declines each year and the rate at which this decline occurs is given by a reduction factor. In 2024, the reduction factor increased from 2.2% to 4.3% a year to 2027, and this is set to increase further to 4.4% in 2028. EU-ETS auctions raised approximately EUR 43.6 billion in 2023, with most of this revenue disbursed to the member states and the remainder allocated to the Innovation Fund, Modernisation Fund and the REPowerEU plan.

The transitional period (2023-2025) of the carbon border adjustment mechanism (CBAM), which is the EU's policy for preventing carbon leakage by pricing carbon emitted in the production of certain products that are imported into the region, started on 1 October 2023. The initial regulation ran from 1 October 2023 until 30 June 2024 and allowed importers to use default values for emission data reporting during this period. However, from July 2024, declarants were required to fully report the emissions from the production of the imported product. During this period, which lasts until the end of 2025, importers must report the greenhouse gas emissions embedded in their imports on a quarterly basis. This period serves as a pilot phase to collect data and refine the methodology in preparation for the full implementation of CBAM.

From 1 January 2026, the CBAM will transition to its final phase. Importers will need to report emissions annually and purchase CBAM certificates equivalent to the carbon content of their imports. The price of the certificates will be based on the weekly average price of EU-ETS allowances. However, if importers can prove that a carbon price has already been paid in the production of the imported goods then this amount can be deducted. The CBAM aims to ensure that the carbon price of imports is equivalent to the carbon price of domestic production, thereby preventing carbon leakage.

Germany

Electricity output from solar PV rose by a staggering 19% in 2024, with its share in total generation reaching 15%

After two consecutive years of declines, Germany's electricity consumption increased by 1.1% in 2024, with renewable power generation meeting the additional demand and partially replacing declining coal output. Particularly noteworthy on the supply side was the surge in PV capacity, which expanded from 82 GW to 99 GW. This expansion led to a significant increase in PV generation of 19%. Wind energy saw minor growth, with onshore capacity rising from 60 GW to 63 GW, and offshore wind capacity increasing from 8.5 GW to 9.2 GW. Despite these capacity expansions, total wind generation saw a reduction of 3.3%.

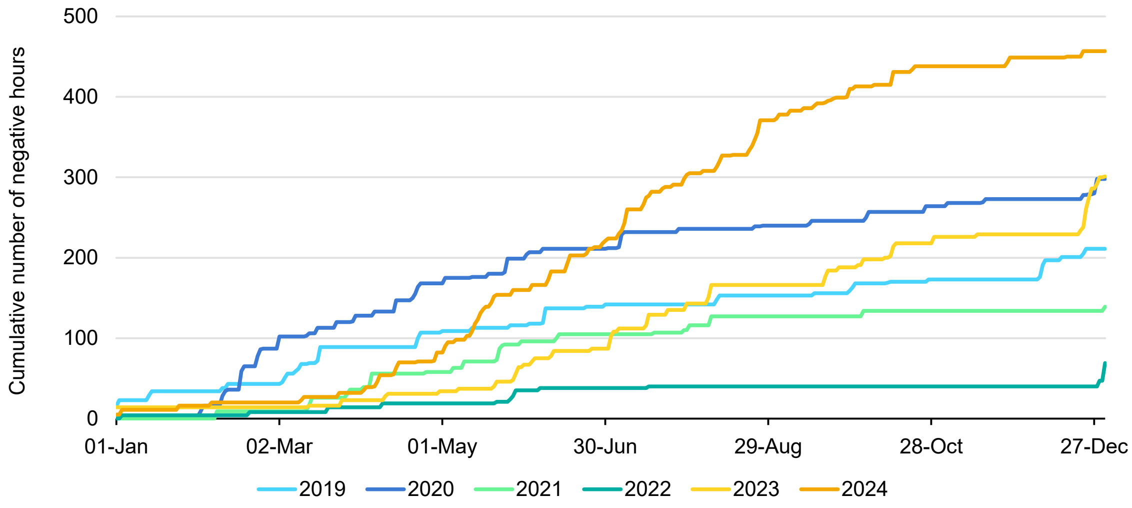
Coal-fired power generation declined by 14% year-on-year, with about 6 GW of coal and lignite plants decommissioned in 2024. Some of these retirements were initially scheduled for earlier dates but were postponed due to the record high energy prices in 2022 and to reduce natural gas consumption in the power sector.

During our forecast period 2025-2027, we anticipate electricity demand to grow by an average 1.2% annually, with renewables supplying all the growth while all other sources of supply decline. PV and wind power generation are projected to increase by average growth rates of 20% and 9%, respectively. Robust growth in renewable energy of approximately 10% per year in 2025-2027 will more than offset the forecast decline of 16% in coal generation and 8% fall in gas-fired power. Germany switched from being a net exporter of electricity to being a net importer in 2023, with total net imports of 9 TWh. In 2024 net imports more than tripled to 32 TWh, and we expect Germany to remain a net importer of electricity over our forecast period.

Of the 96 GW of solar PV capacity, over two-thirds receive a feed-in tariff, which does not provide an incentive to respond to market signals, such as reducing generation during periods of oversupply. Consequently, as PV penetration continues to rise, the frequency of negative wholesale prices has increased in recent years, though the share of negatively priced hours was still less than 5% in

2024. In tandem with the expansion of solar PV capacity, battery storage, which provides flexibility to mitigate negative prices, also experienced significant growth. We expect this trend to continue into 2027, with an additional 3.8 GWh of utility-scale storage reported to the regulator.

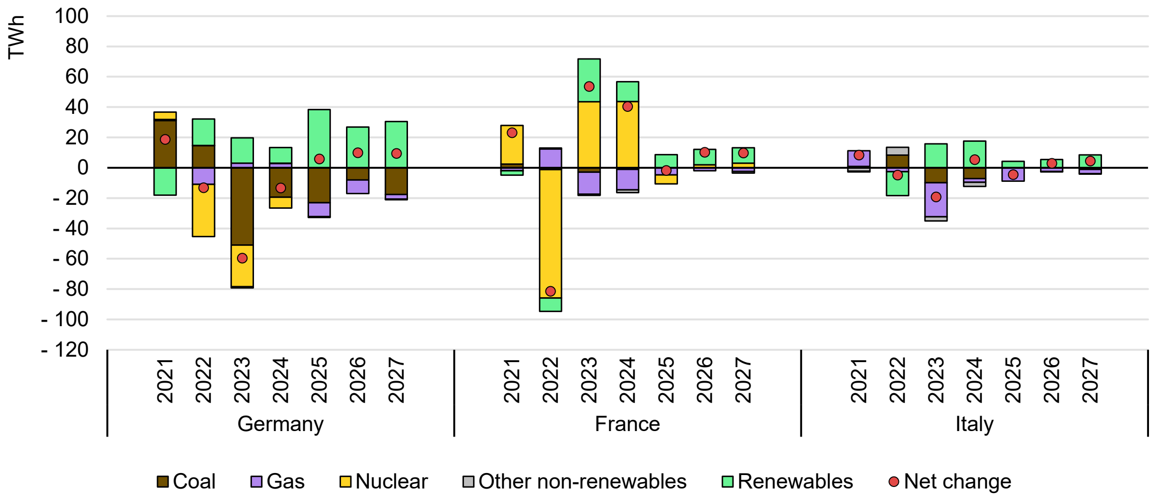
Number of hours with negative wholesale electricity prices in Germany, 2019-2024



Source: IEA analysis based on hourly day-ahead electricity market data from Smard (2024).

With a further 2.3 GW of coal capacity expected to be decommissioned by 2026 and only 1.6 GW of all new firm capacity projected to be added between 2024-2026, the government acknowledged the need to support financing of new capacity investments to ensure security of supply. The German government announced in July 2024 plans to auction capacity payments for 12.5 GW. This includes mostly new gas-fired power plants, some of which must be hydrogen-ready, with a mandate to convert them for hydrogen usage by the end of the 2030s. Political uncertainty may impact the original plans for the capacity auction. Towards the end of the decade, Germany plans to implement a more comprehensive capacity mechanism. The initial proposal envisions a combined capacity market that features central auctions for new capacities and a certificate system to ensure capacity availability during peak demand periods.

Year-on-year change in electricity generation in Germany, France, and Italy, 2021-2027



Notes: Other non-renewables includes oil, waste and other non-renewable sources. Data for 2025-2027 are forecast values.

France

Highest level of electricity exports recorded as nuclear generation showed strong recovery in 2024

Following a major supply-side recovery in 2023, French power market fundamentals continued to strengthen in 2024. Nuclear generation made substantial gains over the second half of the year and renewable power growth maintained its strong momentum. These trends are set to extend into the short term, bolstering France's position as a net electricity exporter.

The French nuclear fleet continued to undergo stress corrosion inspections in 2024 following historic outages in 2022, but streamlined maintenance procedures led EDF to increase nuclear generation targets for the year by early September. Monthly nuclear output had come back in line with the 2017-2021 average by June and tracked above average over the second half of the year, leading to growth of nearly 13% in nuclear generation for the entire year.

Renewable power output grew by over 9% in 2024, with year-on-year gains recorded by solar PV and hydropower. Despite strong capacity additions in 2023 and 2024 (including the commissioning of France's second and third offshore wind farms) helping to drive solar PV generation to new record highs, wind output saw a slight decline. However, hydro provided by far the greatest upside in renewable power generation, growing by 23% y-o-y as above-average rainfall in the spring months helped keep reservoir levels comfortably above recent historical average levels in the second half of the year.

Demand dynamics remained relatively soft, with electricity consumption down marginally in 2024 at just under than 0.5% y-o-y. The combination of lower demand and the continued supply-side recovery helped boost French power exports to their highest-ever level in 2024, particularly as exports through the UK and Belgium/Germany interconnections recovered to above their pre-2022 levels, and despite unavailabilities in France's eastern interconnections. France's net electricity exports in 2024 of 89 TWh were the highest ever recorded in the world. The strong net export trend is set to continue in the short term as the nuclear recovery continues, supported by the commissioning of the Flamanville 3 reactor – France's largest at 1 600 MW – in late 2024 (after a 12-year delay). The unveiling of the draft Pluriannual Energy Programme (PPE3) in November also confirmed the renewed political support for nuclear in the French electricity mix, although concrete impacts – notably from building new reactors and extending existing reactor lifetimes beyond 50 or 60 years – are expected mostly beyond our current outlook period.

Although renewable output growth continues to be subject to annual variations, it is set to maintain its momentum as wind surpasses hydro as the single largest source of renewable electricity in the outlook period. From below 15% in 2023, the share of variable renewables (wind and solar PV) in total power generation rises to 20% by 2027, helping further marginalise electricity output from fossil fuels and waste to below 3% of the power mix.

Overall, the recovery in France's total power generation is forecast to continue at approximately 1% CAGR in our outlook period, bringing output back in line with pre-Covid highs by 2027. With demand expected to recover at moderately higher rates but from a lower starting level, net exports are set to remain strong, on average accounting for a larger share of total generation than in the years immediately preceding the 2022 crisis.

One of the most significant developments in the French power market expected in 2025 is the planned phasing out of the Regulated Access to Incumbent Nuclear Electricity (ARENH) mechanism. At the end of 2025, the system through which alternative electricity providers (i.e. not the incumbent producer EDF) can access a share of nuclear-produced electricity at reduced cost is set to give way to an alternative market-base framework to support competition in the retail energy market. While an initial agreement between the government and EDF on nuclear revenue sharing was reached in late 2023, some details around the functioning of the new mechanism had yet to be confirmed by early 2025.

Italy

Electricity generation from renewable sources surpassed fossil-fired generation in 2024

In 2024, electricity demand in Italy increased by 2.2% y-o-y and was marked by a significant shift in the energy mix, with renewable energy generation surging by 15% and surpassing fossil fuel-fired generation for the first time. By contrast, fossil fuel-based power generation declined by 8.4%. Renewable sources covered 50% of Italy's electricity demand in 2024, up from 44% in 2023. Hydropower showed the largest growth, rising by 28% y-o-y, followed by solar PV with an 18% increase.

Italy's coal phase out is on track to be completed by 2028 as key interconnections between mainland Italy and Sardinia are expected to be brought online. Despite previous plans to phase out coal by 2025 with the closure of the Sulcis plant in Sardinia, this deadline is likely to be extended to 2028 as the full phase out is dependent on the completion of key interconnections, specifically Sacoi 3 and the Thyrrenian Link. The status of these two major interconnection projects, aimed at enhancing grid stability and integration, have been recently updated in the final version of the National Energy and Climate Plan (NECP). The Thyrrenian Link, supported by REPowerEU with EUR 4.5 billion in funding, includes two high voltage direct current (HVDC) connections linking Sicily to Sardinia and Sicily to the Italian mainland. It is expected to be completed by August 2026. The Sacoi 3 project is an HVDC link connecting Sardinia, Corsica and Tuscany and is designed to replace the existing Sacoi 2 with a capacity of 400 MW.

In July 2024, Italy unveiled the final version of its updated National Energy and Climate Plan (NECP) that sets an ambitious target for 63% of electricity demand to come from renewables by 2030. It also outlined plans for significant capacity expansions, including targets of 80 GW of solar PV and 28 GW of wind power by 2030, alongside updated energy efficiency targets. This includes an annual energy savings rate increase to 1.3% for 2024-2025, which is expected to rise to 1.9% per year by 2030. The NECP set annual retrofitting targets at 1.9% for residential buildings and 2.8% for the tertiary sector from 2020 to 2030. The Minimum energy performance standards (MEPs) mandates that 16% of the worst-performing buildings be renovated by 2030 to enhance energy performance.

Spain

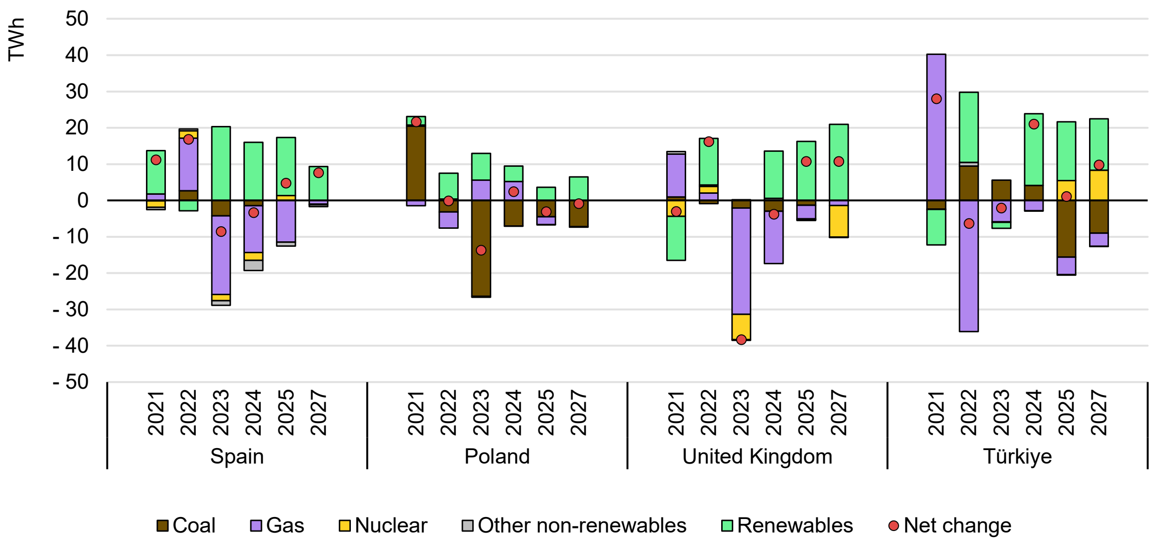
Solar PV generation continues its rapid growth, with its share in total generation nearing 20% in 2024

Electricity demand rebounded with growth of 2% in 2024 on rising industrial and services activity, reversing two years of declines, although demand is still lower than pre-Covid levels. We expect electricity demand to increase by an annual average rate of 1.9% over the 2025-2027 outlook period. New capacity is led by solar PV as Spain has gone through a period of extensive solar expansion in recent years. In 2024, solar PV surpassed wind (30.7 GW) as the largest installed capacity, with over 25 GW at utility scale and an estimated 7 GW of distributed solar PV. By contrast, coal capacity continues to decrease on plant closures, with the shutdown of the Aboño plant expected in 2025.

The high solar PV generation capacity linked with strong hydropower output (up 33% y-o-y in April) pushed wholesale electricity prices below zero in the face of limited demand flexibility during less than 3% of the hours of the year. This was the first time negative prices occurred in the Spanish market, following the implementation of updated rules on the operation of electricity markets in December 2023, which allowed for negative prices. Below zero prices have led to renewable curtailment, but in accordance with TSO data, curtailments have been below 5% of production even in April or March when strong hydropower and solar PV generation were particularly prominent.

In 2024, the government submitted a final updated NECP for 2021-2030. The plan assumed electricity demand growing by 35% compared with 2019, with renewables anticipated to cover 81% of the demand. The schedule of the nuclear power plant closure is unchanged. In accordance with that schedule, Almaraz I will close in 2027, Almaraz II in 2028, and Ascó I and Cofrentes in 2030. Unless there is an uptick in storage, the dependency of the electricity system on combined cycles will increase, which has renewed debate surrounding capacity mechanisms.

Year-on-year change in electricity generation in Spain, Poland, United Kingdom, and Türkiye, 2021-2027



Notes: Other non-renewables includes oil, waste and other non-renewable sources. Data for 2025-2027 are forecast values.

Poland

Coal-fired output declined in 2024 as the share of renewables in total generation neared 30%

Electricity demand in Poland rose of 0.7% in 2024, with higher gas-fired and renewable generation amid lower coal-fired power output. Generation from renewables increased by 9.5% y-o-y and is forecast to average 8.5% growth over the 2025-2027 period. By contrast, coal generation declined by 7% in 2024, and is expected to contract further in 2025-2027, albeit a smaller 5.2% annually. During the same period, Poland's electricity demand is anticipated to grow by an average annual rate of 1.1% due to stronger economic growth and the shift towards electrification.

As renewable energy captures a growing share of the electricity generation mix, rising from 29% in 2024 to 38% in 2027, enhancing flexibility and balancing activities, as well as developing the electricity grid, will be central to ensuring the security of the energy system. On 14 June 2024, Poland implemented a reform of the balancing power market, changing settlement intervals from an hourly to a fifteen-minute basis. The reform opened the balancing market to participants with a minimum generation capacity of 0.2 MW, down from the previous 1 MW. It also addressed operation plans for the national electricity system within the European energy market. Progressing on its 2020 plan for the Implementation of Electricity Market Reforms, Poland aims to increase flexibility in the balancing market in line with EU regulations.

Following Poland's 2022 cap on power prices, the government has extended the measure to cover the latter half of 2024 and into 2025. The maximum power price was set at PLN 500 (USD 123) per MWh for households, an increase from the previous PLN 412 (USD 100) per MWh. The step-by-step curb of energy subsidies sparked concerns over rising inflation in early 2024, however, it is still significantly below levels seen at the height of the energy crisis.

In April 2024, preparations began for the geological survey of Poland’s first nuclear power plant site in Choczewo. Updated in 2020, the Polish Nuclear Power Programme aims to commission the country’s first nuclear reactor by 2033 (1-1.6 GW), with plans to achieve a fleet with a total generation capacity of 6-9 GW by 2043. Poland also opened its first renewable heating plant, which uses a combination of solar PV, heat pumps and a storage system to convert electricity to heat for 2 000 residents. In October, an announcement was made for the start of commercial operation of the country's largest gas-fired power plant, PGE Gryfino Dolna Odra Combined Cycle, of approximately 1.4 GW. Additionally, a EUR 194 million investment aid plan for the construction of an offshore terminal to facilitate the installation and maintenance of wind turbines as well as a

EUR 1.2 billion state aid scheme to support at least 5.4 GWh of newly installed electricity storage facilities have been reported. Both measures were approved by the European Commission in 2024 under EU state aid rules. In November, the Polish multinational Orlen Group obtained a EUR 800 million loan from the European Investment Bank (EIB) to upgrade the country's electricity distribution networks by integrating smart grid technologies and expanding renewable energy connections.

Denmark

Share of wind and solar PV in total power generation rose to a combined 68% in 2024, and is expected to reach 75% by 2027

In 2024, electricity demand in Denmark rose sharply, up by approximately 5%. Renewable generation grew by 8.7%, with solar and wind generation up by 25% and 6%, respectively. The share of renewables increased further in 2024 and now accounts for 87% of total generation. The source of the bulk of this renewable electricity production is VRE, especially wind. Denmark benefits from being well interconnected with sufficient electricity imports and exports, which plays an important role in successful grid integration of VRE sources in the country.

For the 2025-2027 period, electricity consumption is forecast to increase by an average of 3.5% per year, supported by continued electrification of the heating and transport sectors as well as data centres. Coal-fired generation is projected to decline by an average 24% annually as Denmark moves towards its target of phasing out coal by 2028. We forecast continued growth in renewables, averaging about 5% yearly over this period, driven by both solar and wind rising by an annual rate of 14% and 5%, respectively. Denmark is the country with the highest share of VRE in electricity generation mix in the world, with an estimated 68% in 2024. This share is expected to reach 76% over our forecast period.

Denmark launched a tender in 2024 for at least 6 GW and potentially 10 GW of offshore wind capacity, to be completed in 2030. However, the first offshore wind auction in the North Sea I area failed to receive any bids. This was attributed to a multitude of reasons, including large upfront costs and a lack of revenue stability like that provided by CfDs. Another factor is the increasing level of competition from other European countries offering subsidies and using CfDs to attract developers. Other projects like the development of an energy island in the North Sea have seen delays with rising costs and high interest rates impacting project economics.

The Danish TSO Energinet announced a EUR 1.4 billion agreement to expand the grid to support the further integration of VRE. In 2024, Energinet joined the Platform for the International Coordination of Automated Frequency Restoration and Stable System Operation (PICASSO), gaining access to the shared common aFRR balancing energy market. The PICASSO cooperation ensures that aFRR is sourced from the most competitive provider. As a result, Energinet benefits from a more efficient balancing response and a larger pool of balancing resources.

Denmark provided an update to their NECP for 2021-2030 to the European Commission. The government also published a roadmap for energy efficiency outlining current and upcoming work in line with the corresponding EU Energy Efficiency directive. This roadmap details how policies targeting energy behaviour and renovations, electrification, excess heat conversions, as well as flexibility with the support of digitalisation and competencies, can improve energy efficiency.

Ireland

Combined share of solar PV and wind in total generation reached 40% in 2024

Electricity demand increased by 3.8% y-o-y in 2024, continuing the trend of strong growth from previous years. Coal-fired generation decreased by 15% as the country transitions to end coal power use by 2025. Gas-fired generation fell by 3% but remained the largest share of electricity generation in 2024. Wind remains the leading renewable energy source, accounting for approximately 80% of renewable electricity generation in 2024. While wind generation remained stable compared to 2023 levels, solar PV expanded by 80%, supported by growth in other renewable sources, including biomass. This contributed to an overall increase of 4.2% y-o-y in renewable electricity generation.

Over the period 2025-2027, we estimate that electricity consumption will grow on average by 3.3% per year. Gas-fired electricity generation is expected to decline by around 1% annually in 2025-2027, whereas renewables will continue to see strong growth of 12% over the outlook period. We anticipate solar PV and wind power generation to be the primary drivers of increased renewables, averaging growth of 32% and 12%, respectively.

Data centres in Ireland are estimated to have consumed 6.3 TWh in 2023, according to the Central Statistics Office, an increase of 20% over 2022. Accordingly, data centres accounted for about 20% of total electricity consumption in 2023, more than the 18% of total electricity consumption by urban households. Data centres are scrutinised closely at the planning stage, with some applications rejected due to concerns such as how their operation would affect the grid.

Additional investment of EUR 750 million was injected into the development of electricity grid infrastructure, particularly for offshore grid development. One aspect of back-up to the grid will be provided by the Moneypoint 900 MW power station. This was originally a coal-fired power station but is being converted to heavy fuel oil where it will operate as a generator of last resort until 2029. The 700 MW Celtic Interconnector project, which will allow electricity exchange between France and Ireland, is under construction and scheduled to become operational in 2026.

In 2024, the Infrastructure, Climate and Nature Fund (ICNF) was established to provide countercyclical capital expenditure in the event of an economic downturn and to support expenditure on environmental projects from 2026 to 2030. EUR 3.15 billion from the ICNF is designated for projects that assist in the transition to a net zero carbon economy. Government support to provide relief in response to high energy prices for households continued in 2024 in the form of electricity credits, with two EUR 125 payments credited to all domestic electricity accounts. Funding has been allocated to schemes that provide home energy upgrades, including retrofitting and solar PV.

United Kingdom

Renewables surpassed the 50% mark in the share of power generation

Electricity consumption in the United Kingdom rebounded to growth of 2.4% in 2024, driven by data centre expansion and increased electrification, following declines in both 2022 and 2023. The National Energy System Operator (NESO) estimates that data centre demand could increase fourfold by 2030. Electrification is set to progress over the forecast period, evidenced by a 25% share of cars sold being electric in 2023 and the planned tenfold plus rise in annual heat pump installations between 2021 and 2028. Moreover, 80% of cars sold are expected to be zero emission by 2030.

The UK imported more electricity in 2024 as domestic generation declined by about 1.3% compared to previous year. Gas-fired power fell by around 15% in 2024, after falling by 23% in 2023. However, the recent expansion of interconnection capacity allows imports to displace more domestic generation and provide flexibility, compensating for the coal phase out, reduced gas-fired generation and historically low levels of nuclear generation. Generation from renewable energy is correspondingly forecast to increase by over 11% on average annually over the forecast period. Growing renewable generation alongside increased imports allowed the United Kingdom to achieve more than a 50% share of renewables in total generation in 2024.

Coal was completely phased out in the United Kingdom's electricity mix after the final remaining units ceased operation in October 2024. Electricity generation from gas is expected to decline over the forecast period, though several new gas plants are set to be commissioned before 2027 through the Capacity Mechanism, which aims to ensure system adequacy. Long-term plans to raise nuclear capacity significantly by 2050 remain in the early stages.

Imports are able to play a greater role in providing flexibility through the UK's expanding interconnection capacity. Having achieved interconnection capacity of 8.4 GW in 2023, Great Britain's electricity market reached 9.8 GW of capacity in 2024 with the addition of the 0.5 GW Greenlink interconnector with Ireland and the 1.4 GW Viking Link with Denmark, which was commissioned at the end of 2023. NESO forecasts that interconnection capacity will reach 12 GW by 2030 through additional projects, including the NeuConnect 1.4 GW interconnector to Germany, which is set to be commissioned in 2028.

The newly-elected government has stated a goal of 'clean power' by 2030, bringing a shift in policy that seeks to accelerate power-sector decarbonisation. Key interventions so far include permitting 2 GW of solar, removing the ban on onshore wind in England, and agreeing on funding for multiple CCS projects. The government has also established "Great British Energy", a government-owned energy company in partnership with the Crown Estate which aims to lead up to 20-30 GW of new offshore wind seabed leases by 2030. This expands on the Crown Estate's new role in offshore wind development, building on its new powers to borrow up to GBP 400 million to accelerate offshore wind by investing in enabling infrastructure.

Türkiye

Strong electricity demand growth coincided with a rebound in hydro in 2024, limiting the increase in fossil-fired generation

Electricity demand saw a sharp increase of 5.7% in 2024 after a year of relatively flat consumption, with Türkiye accounting for an exceptionally strong 25% of total European demand growth The demand growth was boosted by increased need for cooling as the country's experienced the hottest summer in 54 years. We expect growth to moderate to an average annual rate of 2.4% over the 2025-2027 outlook period.

In 2024, the largest decrease in electricity generation was seen in gas-fired power, which declined by 4.1%. We expect the share of gas in the electricity mix to continue to contract in the coming years, from 19% in 2024 to 12% in 2027. Coal saw an increase of 3.5% but we expect coal-fired power generation to begin to decline this year, with an average annual decrease of 7.5% during 2025-2027.

Renewable forms of power generation saw strong growth, particularly hydropower. Following a decline due to drought at the beginning of the 2023, hydropower generation increased by 17% y-o-y in 2024, the highest levels seen since 2020. Solar PV and wind power generation both saw strong year-on-year growth, at 26% and 10%, respectively, in 2024. We expect both VRE sources to continue to post robust growth in the future as renewable deployment gathers pace, particularly driven by the rapid expansion of solar PV. Solar PV generation is forecast to average yearly growth of 23% over the 2025-2027 period. Total renewable power generation is set to make up 50% of the share of electricity mix by 2027.

Türkiye is planning to quadruple renewable energy capacity by 2035, which would involve increasing renewable generation capacity from 30 GW to 120 GW. To achieve this goal, the government announced an investment target of USD 80 billion in renewable energy and USD 30 billion to improve energy infrastructure. This is intended to help Türkiye achieve its 2053 net-zero target.

To achieve the goal of net zero by 2053, nuclear is anticipated to play a critical role. Türkiye is building its first nuclear power plant with the first phase completed in Akkuyu in 2024 and the first reactor currently expected to be commissioned later in 2025. More nuclear power plants are being planned in Sinop and the Thrace region.

Ukraine

Russia's full-scale invasion of Ukraine leaves half of electricity generation capacity out of service

Having declined by 30-35% in 2022 in the wake of the full-scale invasion by Russia, peak electricity demand for the winter of 2024/2025 is expected to rise to within 23% of pre-war levels due to high heating needs. Simultaneously, Russia's ongoing attacks on Ukraine's energy infrastructure have significantly reduced electricity generation capacity, with approximately half of it having been occupied, damaged or destroyed by the end of 2023. As of May 2024, 70% of thermal generation capacity remained unavailable, increasing Ukraine's reliance on its remaining nuclear plants.

Recent attacks have highlighted the risk to supply from nuclear plants as damage to nearby substations can prevent these facilities feeding the grid or endanger the backup supply that keeps the reactors safe. Therefore, alternative electricity sources are also being prioritised. Renewable energy sources are playing an increasingly important role, representing 18% of electricity generated in 2023, with solar and wind contributing about 29% of renewable generation, and the majority of the remainder from hydroelectric power. While this percentage may decrease as a share of traditional generation capacity is rebuilt and recovered, the installation of new renewables is projected to steadily increase.

This rising level of demand and reduced generation capacity resulted in a electricity deficit exceeding 2.3 GW during the summer months and in significantly higher levels during the winter. Managing this deficit has necessitated rolling blackouts and scheduled interruptions, which amounted to just under 2 000 hours in 2024. In some regions, electricity supply has been limited to only a few hours a day, particularly given the prevalence of massive attacks on energy infrastructure. Decentralised renewable energy installations combined with storage systems are beginning to be deployed across the country, which can provide four hours of backup power supply to critical infrastructure, such as water supply systems and healthcare facilities.

Looking ahead to the winter of 2025/2026; interconnections and the development of new generation infrastructure will be critical in offsetting the power supply deficit. On 1 December 2024, the interconnection capacity between the neighbouring EU TSOs and the combined systems of Moldova and Ukraine was increased from 1.7 GW to 2.1 GW, with the possibility of an additional 250 MW in emergency assistance. Conservative estimates expect 1.2 GW of interconnection capacity to be added for the winter of 2025/2026.

In neighbouring Moldova, electricity supply risks stem from the dependency on the Moldovskaya GRES power plant in the breakaway, Russian-backed region of Transnistria. In 2024 the plant covered two-thirds of the country's electricity demand, benefitting from an agreement with Gazprom, whereby they received gas volumes via Ukrainian transit for free and then sold on the electricity to Moldova. The Gazprom-Ukraine gas transit deal came to end on December 31, 2024, which has resulted in a state of emergency for both Moldova and Transnistria. Uncertainty with the continuity and costs of this gas supply through rerouting poses risks to the country's electricity supply. These risks may spill over to Ukraine's electricity balance if Moldova increases its reliance on imports throughout 2025, until new interconnector projects such as the Vulcanesti-Chishinau 400 kV line are completed.

In the longer term, Ukraine's energy system integration with the European Union and ENTSO-E requires a number of reforms. Market coupling of Ukraine's day-ahead, intraday, and balancing market with those of the European Union is expected to gradually be implemented in the next 2-3 years. This will further facilitate cross-border electricity trade and effectively utilise price signals to incentivise desired market behaviour.

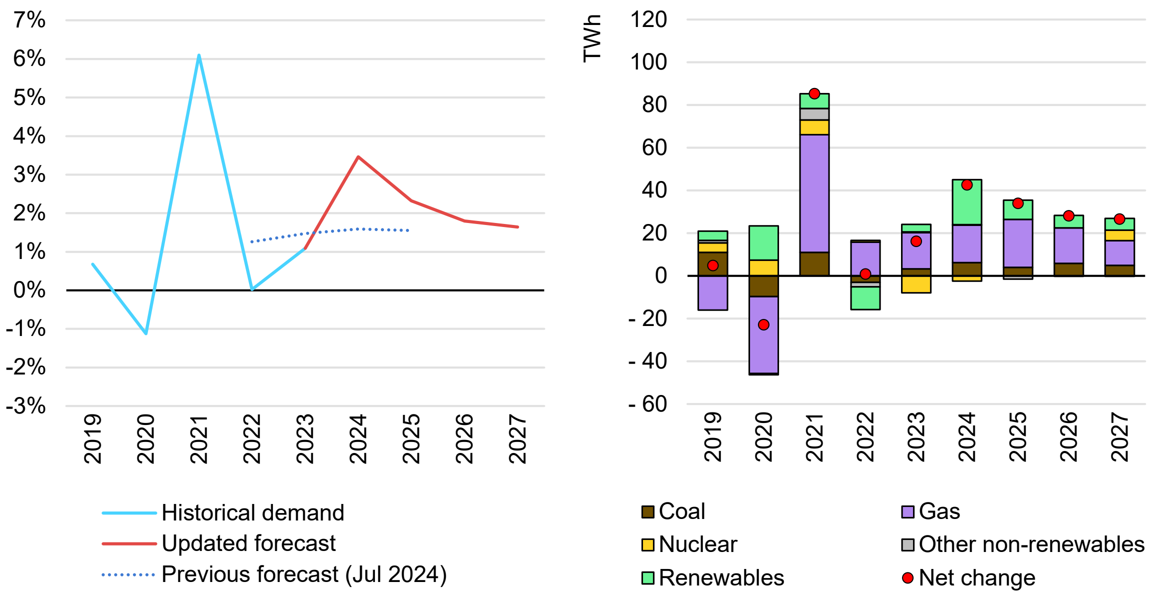
The information made in this section are based on assumptions and forecasts of information available at the time of writing. However, due to the ongoing conflict and rapidly changing situation in Ukraine, these estimates are subject to change.

Eurasia

Eurasia returned to stronger electricity demand growth in 2024

Eurasia's electricity demand grew by 3.5% in 2024 – its strongest growth rate since 2021, when the post-Covid recovery boosted the region's consumption by almost 6%. Industrial activity related to Russia's full-scale invasion of Ukraine, economic stimuli and adverse weather effect supported higher electricity demand growth in 2024. The region's demand growth is expected to moderate to an average annual rate of 1.9% over the 2025-2027 forecast period. Fossil-fired power generation will continue to dominate Eurasia's electricity mix with a share of around 66% over the forecast period.

Year-on-year percent change in electricity demand (left) and year-on-year change in electricity generation (right), Eurasia, 2019-2027



Notes: Other non-renewables includes oil, waste and other non-renewable sources. Data for 2025-2027 are forecast values.

Russia

Electricity demand growth is estimated to have increased by around 3% in 2024

The availability of energy-related data has deteriorated since Russia's full-scale invasion of Ukraine, making it difficult to estimate the country's electricity consumption. Russia's electricity demand is estimated to have grown by around 3% in 2024, a marked increase from the 1.3% growth the previous year. Industrial activity related to Russia's war against Ukraine, economic stimuli measures and adverse weather effects (heatwaves during the summer and colder than average weather in Q1 and Q4) supported higher electricity consumption.

Russia's overall electricity generation increased by 2.4% y-o-y in 2024. Fossil fuel-fired thermal generation rose by 2.7%. Nuclear power output declined by 1% y-o-y in 2024, while hydropower generation was up by near 5% y-o-y. Solar and wind power generation rose by 9.6% and over 27% y-o-y, respectively. In 2024, Russia faced power shortages and blackouts in the southern region, primarily due to insufficient maintenance and a lack of equipment for new construction due to technology sanctions.

Russia's electricity exports dropped by more than 20% in 2024, while imports rose by around 10% y-o-y. The country's electricity exports to China continued to decline and dropped by over 70% y-o-y in 2024, as lower hydro availability and maintenance at thermal power plants in Russia's Far East weighed on the region's ability to export electricity.

Electricity demand growth is forecast at a slower rate of 1.5% on average in the 2025-2027 period. Nevertheless, there is significant uncertainty surrounding Russia's economic development and the structure of its economy, which can impact electricity demand trends in the country. The share of fossil-based thermal generation in the country's power mix is set to remain near 63% on average over the forecast period. The build-up of wind and solar capacity remains slow. Unit 1 of the Kursk II nuclear plant is expected to be commissioned in 2025.

Kazakhstan

Economic growth continued to drive stronger electricity demand in Kazakhstan

A robust macroeconomic performance, with GDP expanding by around 4%, supported stronger electricity demand growth in 2024. The country's electricity consumption rose by 4.2% y-o-y in the first eleven months of 2024, and we forecast an average annual increase of 2.5% over the 2025-2027 period, primarily met by the expansion of gas-fired power generation and renewables.

Kazakhstan's power generation rose by 4.8% y-o-y in January-November 2024. Fossil-based thermal generation accounted for about 85% of the country's generation mix, with coal providing 60% and gas-fired power around 25%. Coal-based generation was up by approximately 1.3% y-o-y over the same period, while gas-fired power increased by almost 8% y-o-y. Following the dry weather conditions in 2023, Kazakhstan's hydropower generation surged by almost 30% y-o-y in 2024. Domestic power generation was also supported by stronger wind output, which increased substantially, to over 4 TWh, in the first eleven months.

Other Eurasia

Combined electricity demand grew in other Eurasian markets by 4% in 2024. Electricity demand in Eurasia excluding Kazakhstan and Russia is forecast to rise at an average growth rate of 3.7% per year in the 2025-2027 period. This will be largely supported by the region's rising population and economic expansion.

In **Uzbekistan**, electricity generation rose by 4.7% in 2024. The country's electricity mix is largely dominated by gas-based generation, although Uzbekistan is taking steps to diversify and to develop renewable power generation capacities. The country is planning to raise combined wind and solar power generation capacity to 20 GW by 2030.

In **Azerbaijan**, electricity demand rose by almost 4% in 2024, a significant increase from 2023. Electricity production in Azerbaijan declined by nearly 3%. Fossil-fired thermal generation (largely gas-based) fell by 10%, while hydropower output increased substantially. Electricity exports from Azerbaijan declined by almost 60% in 2024.

In gas-rich **Turkmenistan**, electricity generation continued to expand in 2024. The country continues to increase electricity exports to neighbouring markets, including to Afghanistan, Iran, Kyrgyzstan and Uzbekistan. Turkmenistan started electricity exports to Kyrgyzstan in August 2021, with deliveries reaching 1.6 TWh in 2023, and planned to export between 1.7-2 TWh in 2024. In January 2024, Turkmenistan agreed to supply 1.8 TWh to Afghanistan. In October 2022, Turkmenistan and Uzbekistan reached an agreement to ramp up electricity supplies to 4 TWh/yr, although actual trade volumes were not disclosed.

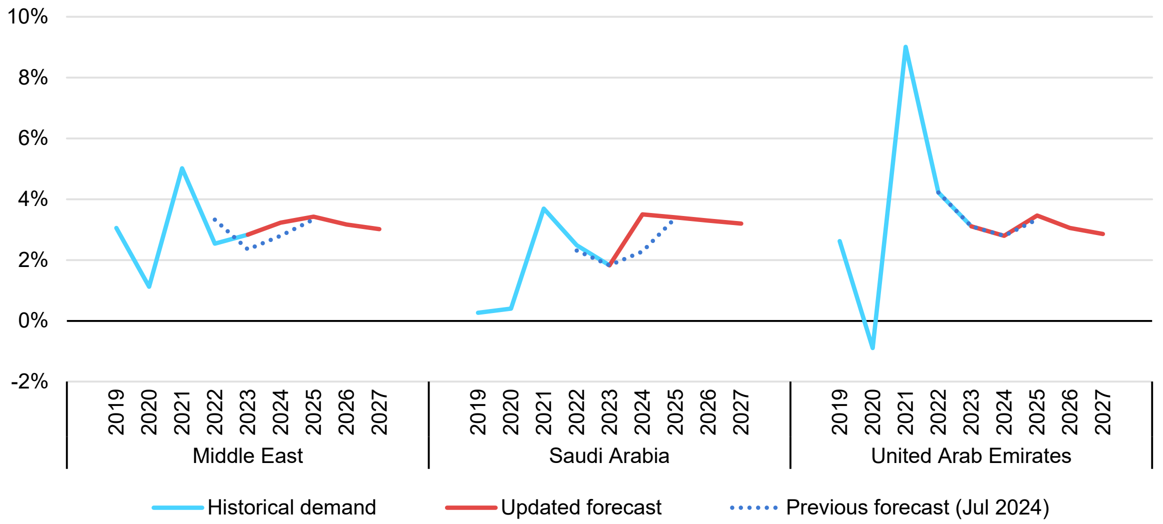
Middle East

Switching from oil to natural gas in power generation is expected to gain pace

The Middle East saw growth in electricity demand of 3.2% in 2024, up from 2.8% in 2023, in large part due to an exceptionally hot summer season boosting air conditioning use. We expect the region's growth to continue near this higher level at approximately 3% on average over the 2025-2027 outlook period as economic growth and strong cooling demand continue to support consumption levels.

Gas-fired generation grew by 2.9% in 2024, the primary source of power in the region, and is forecast to accelerate to an average annual 5.3% during 2025-2027, as further fuel switching from oil to gas takes place in line with government policies, with its share of the electricity mix rising from 68% to 73%. Renewable generation is forecast to grow by approximately 14% a year during 2025-2027, albeit from a low baseline, with its share rising from 5% to 7%. Solar PV dominates growth, with its share of renewable generation increasing from around 55% to almost 70% by 2027, while hydropower contracts from over 30% to just below 20%. Saudi Arabia, the United Arab Emirates (UAE) and Israel saw significant gains in solar PV generation, accounting for the majority of the solar growth in the region. We expect annual average growth of 23% for solar in 2025-2027. Nuclear also played a more prominent role in power generation in 2024, up 20% y-o-y, led by the UAE.

Year-on-year percent change in electricity demand, Middle East, 2019-2027



Note: Data for 2025-2027 are forecast values.

Saudi Arabia

Oil-fired generation contracts sharply as switching to natural gas accelerates over the forecast period

Electricity demand grew by a strong 3.5% in 2024 on increased air conditioning consumption amid extremely hot temperatures and an improved economy, almost double the 1.8% increase of the previous year. Growth is expected to be maintained at similar levels over the forecast period to 2027, at an average annual rate of 3.3%.

Saudi Arabia's focus on expanding natural gas use for electricity led to a decline in oil-fired generation of 3.8% in 2024, and we now forecast an even sharper contraction of over 15% in the 2025-2027 forecast period. The share of oil in the generation mix will drop from slightly above 40% in 2023 to just over 20% in 2027 as gas use rapidly expands. Saudi Arabia is strategically investing in gas production and new gas-fired generation to meet rising electricity demand and replace oil burn in power plants. Gas-fired power, the primary source of supply for electricity, rose by around 6.5% in 2024, and we forecast much higher growth of 10% over the outlook period, with its share of total supply rising from 60% in 2024 to 74% in 2027.

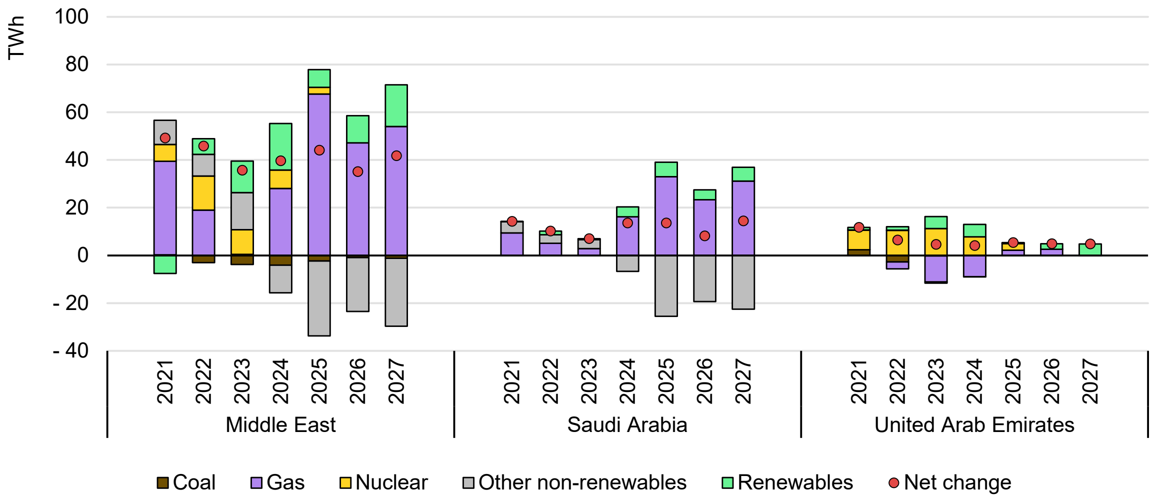
State-owned Saudi Aramco signed a USD 1.5 billion deal with Siemens Energy for two gas-fired power plants with a combined capacity of 4 GW. The Taiba 2 and Qassim 2 plants are being built in the country's western and central regions, with grid connection expected by 2026, and full operation reached one year later. The related emissions savings from the new plants are forecast to represent 60% relative to oil-fired equivalents. This contract is complementary to the USD 10 billion plan to expand the country's massive Master Gas System (MGS) aimed at fast-tracking oil-to-gas switching at power plants.

The MGS Phase 3 project also includes converting a number of Saudi Arabia's existing power plants from oil to natural gas, contributing to the goal of eliminating most oil-fired electricity generation by 2030. The Saudi Electricity Company (SEC), along with GE Vernova and Alfanar Projects, started work on converting the 3.5 GW Power Plant 10 in Riyadh (PP10), one of the largest power stations in the world, at end-2023. The new PP10 gas-fired plants will save up to 60% of CO_2 compared with oil-fuelled operations, with the project expected to lower carbon emissions by 1.7 MT per year. Recent gas discoveries, including the country's largest unconventional natural gas field Jafurah, will be supporting this plan.

Saudi Arabia is also accelerating its renewable power expansion, led by solar PV, which generated more than 5 TWh for the first time in 2024. We anticipate overall annual growth for renewable power generation to average around 55% over the outlook period. The increase in renewables is set to lower the emission intensity of power generation by around 3% a year in 2025-2027.

A sixth round of licensing for renewables was launched on 24 September 2024 and will bring the combined capacity of operational, under development and out-of-tender plants up to 28.2 GW. An estimated 5.3 GW is expected to be commissioned in 2025. The surge in renewable power capacity will contribute to meeting growing domestic electricity demand, reducing the country's dependence on oil-fired power generation, and driving down power sector emissions. The Kingdom plans to reach a renewable power capacity of 100-130 GW by 2030.

Year-on-year change in electricity generation in the Middle East, 2021-2027



Notes: Other non-renewables includes oil, waste and other non-renewable sources. Data for 2025-2027 are forecast values.

United Arab Emirates

Share of low-emissions sources in power generation reached 35% in 2024, up from only 3% in 2019

Electricity demand rose by 2.8% in 2024 and is expected to increase at a slightly higher rate of around 3% over the forecast period. Strong year-on-year growth in solar PV of 29% and nuclear of 25% helped displace thermal generation, which was down by almost 8% y-o-y. These supply shifts drove down the emission intensity of the power sector by 10% in 2024 and this declining trend is expected to continue with an average 1.5% annually over the 2025-2027 forecast period.

Power generation rose to a high of 164 TWh in 2024, of which 40 TWh was generated from nuclear (+25% y-o-y), with the Barakah nuclear power plant reaching its full 5.6 GW capacity this year. According to the state-owned power off-taker Emirates Water and Electricity Company (EWEC), which has been holding quarterly clean energy certificate auctions, 85% of them have been powered by the Barakah nuclear power plant. This has supported the country's industrial decarbonisation efforts, including heavy industries such as aluminium.

VRE sources, exclusively Solar PV, rose by over 28% in 2024, and growth will continue at around 15% on average in 2025-2027, with its share in the mix of 9% expected to rise to 13% by the end of the forecast. Several new renewable projects are supporting growth, with the Mohammed bin Rashid Al Maktoum (MBR) Solar Park in Dubai, currently with 2.9 GW capacity, moving into its Phase 6, which should bring Dubai's renewables generation to 4.7 GW by 2026, close to its 5.3 GW target by 2030.

Other Middle East

Kuwait

Kuwait is facing a worsening power crunch amid growing demand, stagnating capacity, and an ageing generating fleet. As of 2023, the country's total generating capacity was just over 20 GW, almost unchanged since 2020. At the same time, electricity demand has grown, straining the grid and leading to periodic outages during the peak summer period. Electricity demand rose by 4% in 2024 and is forecast to increase at an annual average rate of 3.3% between 2025 and 2027, driven by strong population growth, mounting water desalination requirements, and rising cooling demand during the peak summer period.

Kuwait's generation is dominated by natural gas-fired units, which make up over 50% of the fleet, while most of the remainder is composed of older, less efficient power plants capable of running on oil or natural gas. Kuwait has a renewable fleet of just over 110 MW, which accounted for about 0.5% of its installed capacity and total generation in 2023. To address the challenges associated with the country's ageing and insufficient power infrastructure, the Ministry of Electricity and Water (MEW) has long-term plans to modernise or develop 7.5 GW of new combined-cycle gas turbine (CCGT) capacity, but as of mid-2024 only a 900 MW expansion at the Sabiya power complex had been approved with a targeted online date at the end of 2025. Under the country's Vision 2035 plan, Kuwait set the goal to generate 15% of its electricity from renewables by 2030, implying a capacity of 14 GW. As a first step towards this goal, the government launched a tender and shortlisted six potential developers for the 1.1GW third phase of the Dibdibah Power and Al-Shagaya solar project, but capacity will not come online until after our forecast period.

Qatar

In 2024, Qatar's electricity demand saw an estimated increase of slightly below 5%, and we expect growth of 3.8% over the 2025-2027 period as accelerating economic activity and the start-up of large industrial facilities (including the expansion of the Ras Laffan petrochemical complex) continue to support higher consumption. The vast majority of gas-rich Qatar's 13 GW installed generating capacity in 2023 is made up of gas-fired power plants (94%). In 2022, Qatar commissioned its first large-scale solar project, the Al Kharsaah Solar PV Park, with a capacity of 800 MW. By the end of 2024, Qatar's total solar PV capacity reached almost 1.7 GW following the completion of a 458 MW solar project at the Ras Laffan LNG facility and a 417 MW project at the Mesaieed Industrial City by QatarEnergy. The 2 GW Dukhan solar project is in an advanced stage of planning. In May 2024, Qatar published its first renewable energy strategy, which aims to bring the country's renewable capacity to 4 GW by 2030, and the share of renewables in the electricity mix is targeted to reach 18% by the end of the decade. However, even with this ambitious rollout of solar capacity, the share of renewables in Qatar's generation mix is only projected to increase from 3% in 2024 to 5% by 2027, while the share of gas-fired power plants is expected to decrease only marginally, from 97% to 95% over the same timeframe.

Oman

Oman's electricity consumption increased by nearly 6% in 2023, driven by strong population growth and the development of power-intensive industrial projects. Electricity demand growth in 2024 and the following three years is set to moderate to an annual rate of around 3%. Oman's power generating fleet (totalling 14.5 GW) is dominated by gas-fired power plants, which accounted for 94% of installed capacity and 93% of total generation in 2023. As of 2023, Oman had 672 MW of installed solar PV capacity (including the 500 MW Ibri II facility, its only utility-scale solar PV project) and a 50 MW wind farm. An additional 1 GW of solar capacity (Mahah I and II) is under construction and scheduled to enter service in 2025, while another 1 GW of solar and 1.2 GW of wind capacity is in various stages of development, targeting completion by the end of 2027.

With no new gas-fired power plants under construction, the share of renewables in Oman's total generation is projected to increase from 4% in 2023 to around 12% by 2027, while the share of gas is set to drop from 93% to 85% over the same period. Oman's ambitious north-south grid interconnection project, Rabt, completed its first phase in November 2023 and launched the second phase in 2024, with a scheduled online date in 2027. In a major step towards improving the efficiency of energy use, the government is planning to phase out electricity subsidies by 2025 following a temporary 15% subsidy increase in 2022-2023.

Israel

Israel's electricity consumption declined by over 1% in 2023 due to the economic disruption following the conflicts in the region. Power demand recovered in 2024 at a rate of 2.6%, and a similar annual average growth rate of 2.8% is projected for 2025-27.

Israel has a predominantly natural gas-based generating fleet. At the end of 2023, the country's 23 GW installed capacity was comprised of 12.3 GW of gas-fired units, 4.8 GW of coal-fired blocks and 5.9 GW of renewables, mainly solar PV. The government plans to convert the remaining coal-fired units at Orot Rabin (2.6 GW) and Rotenberg (2.25 GW) to gas by 2026, although the country's state-owned power utility IEC noted that a delay to 2027 is possible due to the uncertain geopolitical environment. Israel has also taken precautionary steps to restart mothballed units at the two remaining coal plants if needed and has stockpiled coal and diesel fuel for emergencies.

Israel's renewable capacity has expanded significantly in recent years and crossed the 6 GW mark in early 2024. Various integrated solar PV and storage facilities came online, and construction is ongoing at several utility-scale renewable projects, such as the 100 MW Ashalim 3 solar PV project in the Negev Desert. IEC is also building two new CCGT units with a combined capacity of 1.2 GW to replace idled coal-fired units at the Orot Rabin site. The new gas-fired units are expected to be operational in 2025.

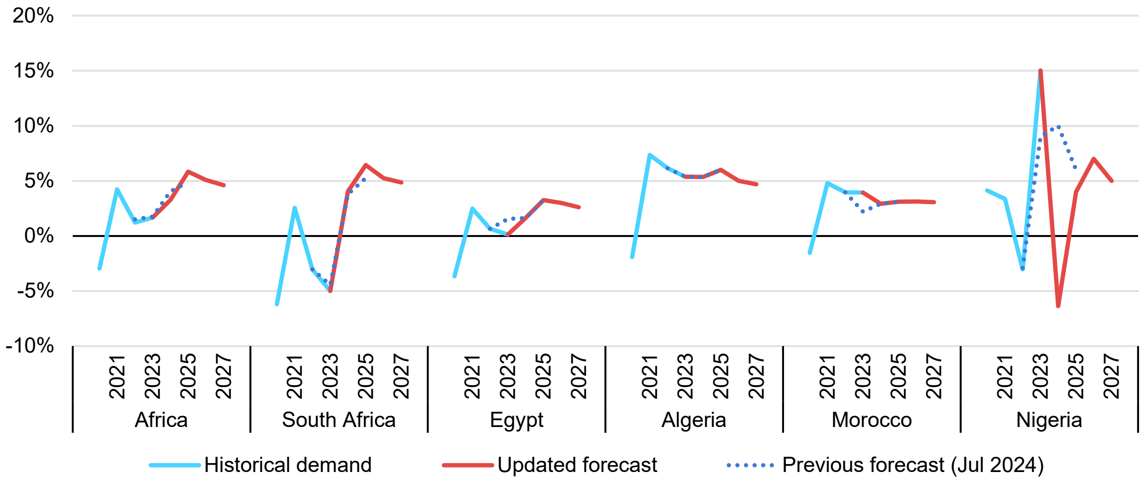
Our projections anticipate a delayed phase out of coal for supply security reasons, and coal-fired generation is expected to retain a 6% share in Israel's generation mix in 2027 (down from 12% in 2024). The share of gas in the power mix remains steady at just over 70% throughout the forecast, while the contribution of renewables increases from 16% to 23% between 2024 and 2027.

Africa

Electricity consumption growth is hampered by insufficient generation capacity

Electricity demand in Africa grew by an estimated 3.4% in 2024, up from just under 2% in 2023. South Africa bounced back from a contraction in demand in 2023 to growth of 4.1% as new capacity was brought online and the power sector limited load shedding. Egypt saw an increase in the yearly rate of demand growth to 1.6% and Algeria continued the trend of strong growth of recent years with a rise of 5.4%. These three countries combined consume over half of all electricity in Africa. We expect this trend of rising electricity demand throughout much of the continent to continue over the 2025-2027 period, averaging approximately 5% per year. Nevertheless, electricity consumption growth is hampered, especially in sub-Saharan Africa, due to lack of supply.

Year-on-year percent change in electricity demand, Africa, 2020-2027



Note: Data for 2025-2027 are forecast values. The years on the x-axis start at 2020.

Natural gas-fired generation in 2024 saw an increase of 2.2% and renewable generation of about 5.5% to meet the higher demand for electricity. Traditionally, hydropower had the biggest share of renewable generation at over 80% in 2018, but its share has declined to just over 70% in 2024, as solar PV and wind increased. Wind power generation rose by approximately 4.5% and output from solar PV grew by a substantial 46% in 2024. This rapid growth in solar PV is expected to continue in 2025-2027, at an average annual growth rate of over 25%.

The expansion of renewable power generation will be important to meet the electricity demand over the outlook period.

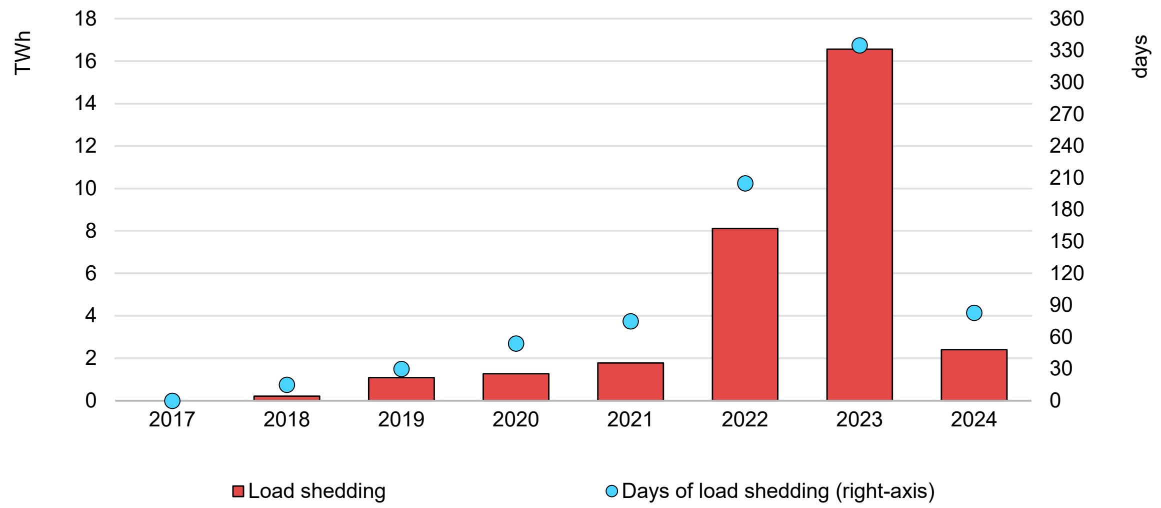
South Africa

Struggling power sector shows first signs of recovery as capacity comes online amid increasing demand

After several years of contractions, electricity demand bounced back, with growth of 4.1% y-o-y in 2024. This reverses the trend that started in 2018, when the current energy crisis began, which saw demand reductions in all years except a post-Covid bounce in 2021.

South Africa is still struggling with power generation shortages, straining the electricity sector. However, load shedding has been limited since March 2024 and Eskom expects to avoid load shedding until at least April 2025. This is a substantial difference from the high levels of load shedding seen in 2023 and is mainly driven by improved thermal power station performance. The South African grid also saw significant capacity expansion with an 800 MW unit starting up in July at the Kusile coal power plant and the first 100 MW concentrated solar plant in sub-Saharan Africa coming online in mid-2024. Further, the 1.9 GW nuclear power plant Koeberg received a twenty-year extension, while Eskom delayed the decommissioning of several coal power plants.

Load shedding in South-Africa, 2017-2024



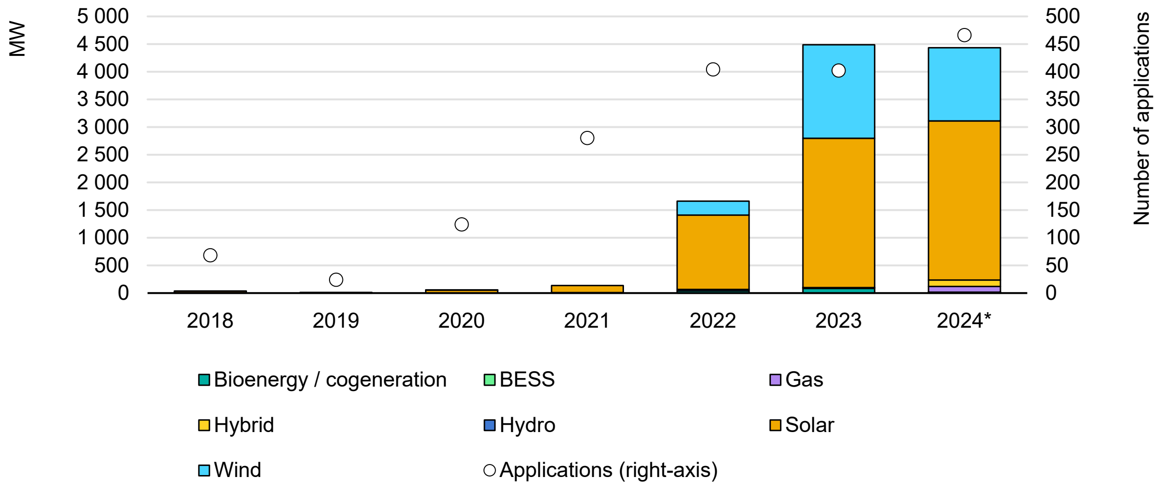
IEA. CC BY 4.0.

Source: Eskom (2024), Eskom Data Portal.

Although the amount of load-shedding has decreased, electricity tariffs for consumers are rising significantly. The National Energy Regulator of South Africa (NERSA) recently approved a tariff hike application by Eskom for 12.6% to start on 1 April 2025, for the financial year 2025/2026. While it helps Eskom's finances, this may be a tough blow for consumers that already saw increases of 18% and 13%, respectively, in the last two years.

The installation of distributed energy resources is continuing to expand. Due to an easing of licensing requirements for private generators in 2023, there has been a sharp rise in private projects from 2022 onwards, with more than 4 400 MW installed in 2024. This is primarily driven by solar and wind, seeing increases over the last year of 2.8 GW and 1.3 GW.

Installation of private generation facilities in South Africa, 2018-2024



Note: Data for 2024 is up to 19 December.
Source: National Energy Regulator of South Africa (2024), Registered Generation Facilities (19/12/2024).

Grid constraints are currently a major roadblock for renewable energy deployment, especially for wind projects. Regulatory obstacles have hampered grid expansion, while transmission bottlenecks have forced Eskom to curtail renewable energy, leading private producers to seek compensation for revenue losses. In early 2024, Eskom introduced a curtailment framework permitting up to 10% curtailment for wind projects, which opens 3 470 MW of additional transmission capacity. To accelerate infrastructure build-out, the government is considering private sector investment in grids, particularly in regions with large constraints such as the Northern, Eastern and Western Cape.

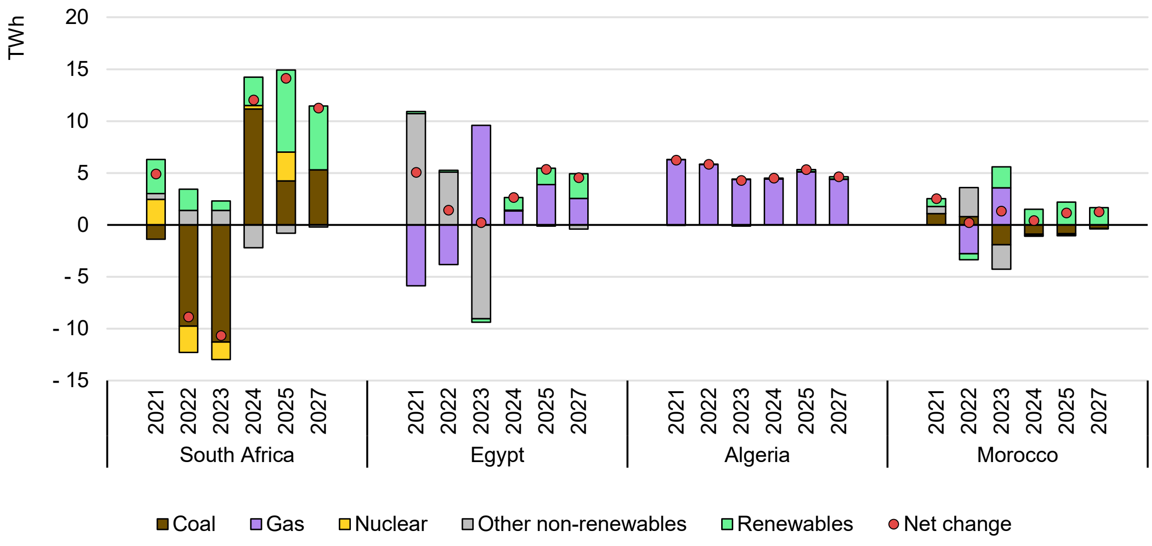
Important policies and frameworks were introduced to facilitate market liberalisation and unbundling

In 2024, there was strong progress towards the liberalisation of the power sector. Most notably, the government introduced amendments to the Electricity Regulation Act (ERA). The act provides the groundwork for an open market for wholesale and retail electricity, with NERSA empowered to license market operations and develop a code to regulate them. To ensure fair competition, the system operator must offer non-discriminatory access to transmission and distribution networks. Additionally, severe penalties have been introduced for damaging power infrastructure.

Another key milestone in power sector liberalisation took place in July 2024 when the National Transmission Company of South Africa (NTCSA) started trading, which marked the next step in the unbundling of Eskom, South Africa's vertically integrated utility. NTCSA will also perform the role of interim-TSO while a new transmission operator is being created between now and 2029, as mandated by the ERA.

Looking ahead, the government has released a draft Integrated Resource Plan 2023 (IRP) laying out its strategy for the power sector until 2030. Compared to the plan released in 2019, it increases total planned capacity by about 11% to 84 GW. The IRP maintains coal capacity by scrapping prior decommissioning plans, adding 1 440 MW of coal, and excluding the Grand Inga hydro project. Despite a 150% increase in distributed capacity, there is a reduction in planned VRE capacity of 17%, due to a 29% decrease in solar PV and a 55% cut in wind. Notable additions include 4 GW in battery energy storage and nearly 11 GW in gas generation to stabilise the grid.

Year-on-year change in electricity generation in South Africa, Egypt, Algeria, and Morocco, 2021-2027



Notes: Other non-renewables includes oil, waste and other non-renewable sources. Data for 2025-2027 are forecast values.

Egypt

Egypt issued contingency plans to balance electricity supply and demand amid blackouts

In 2024, Egypt continued to struggle with balancing electricity supply and demand amid recurring blackouts. Electricity consumption rose by 1.6% y-o-y, driven by population growth, economic expansion and an increasing need for space cooling. While demand for fossil fuels remained stable, renewable power production expanded by almost 5%. For the 2025-2027 outlook period, total electricity consumption is expected to grow by just under 3% per year, supported by the continued expansion of renewable sources at an average annual 7.1%.

However, Egypt faces the challenge of declining domestic gas production, particularly from the Zohr gas field, which resulted in the country becoming a net importer of LNG in 2024. To address recurring blackouts, particularly during peak summer months, the government launched contingency plans to increase oil fuel reserves for power plants and issued a significant number of tenders to purchase LNG cargoes for the winter of 2024/2025 to stabilise electricity supply during periods of high demand.

The government has set ambitious renewable energy targets, aiming for 40% of the energy mix to come from renewables by 2040, including significant investment in green hydrogen. In addition, Egypt began construction of the fourth unit of the El Dabaa nuclear power plant in January 2024, with each unit having a capacity of 1.2 GW. The country is also actively working on electricity interconnection projects with neighbouring countries to create the Arab Common Electricity Market.

In 2024, Egypt introduced significant policy changes to enhance the electricity market's competitiveness and sustainability. The Egyptian Electric Utility and Consumer Protection Regulatory Agency (EgyptERA) issued new rules for private-to-private electricity schemes, aiming to boost private sector involvement in renewable energy production and facilitate the transition towards a competitive electricity market. Additionally, the Ministry of Electricity announced a substantial increase in household electricity prices, with rates set to rise by up to 50%. This decision aligns with recommendations from the EgyptERA to reduce energy subsidies, reflecting the government's commitment to fiscal sustainability and market efficiency.

Algeria

Electricity demand growth to average over 5% in 2024-2027, while renewables play a limited role

Electricity demand in Algeria is estimated to have grown by 5.4% in 2024 and is forecast to grow by 5.2% on average annually to 2027. Natural gas remains the predominant source of power generation in the major gas producing country with a 99% share, while renewables contribute around 1%. Gas-fired output is estimated to have increased by about 4.7% in 2024, similar to its growth rate in 2023. We expect the increasing trend in gas-fired generation to continue over the forecast period, with an average annual growth rate of 4.5%.

On 17 July 2024, Algeria hit a new peak demand record at over 19 GW. With installed capacity of over 25 GW due to grid enhancements and a partial start-up of the 1.5 GW CCGT Mostaganem power plant, Algeria is able to manage rising demand. The delayed power plant, initially scheduled for full operation by 2017, is expected to be completed by 2025.

Algerian national oil company Sonatrach and utility Sonelgaz signed an MoU with Italy's Eni on 31 July to conduct a feasibility study for an electricity interconnection between Algeria and Italy. While Algeria maintains its 15 GW renewable power generation target by 2035, current capacity remains below 600 MW. Sonelgaz moved forward with a 3 GW solar capacity project awarded in March. Nevertheless, Algeria will need to rapidly expand renewable deployment to ensure they reach their capacity targets. Having increased by 13% in 2024, we forecast solar PV generation to grow on average around 22% annually out to 2027.

Morocco

Rapid deployment of solar PV and wind contribute to renewables making up a larger share of power generation

Morocco’s electricity consumption rose by almost 3% in 2024 and is expected to continue at this rate over the forecast period. While the share of electricity generation from renewables grew to 24% in 2024, coal-fired power remains Morocco’s primary source, with a share of 60% in total electricity supply. However, coal-fired output is expected to continue declining over the forecast period by an average of 2.5% annually, with its share in electricity generation easing to almost 50% in 2027.

Renewable generation is forecast to grow by 16% on average over the outlook period, with its share rising from 24% in 2024 to 35% in 2027. Solar PV generation is expected to grow rapidly, with an average annual growth rate of 57% in 2025-

2027, while wind is projected to grow at an average of 15% per year. Morocco aims to increase the share of installed capacity of renewable generation to at least 52% by 2030.

As Morocco focuses on diversifying generation and integrating renewables, grid flexibility and battery technology have become central to the country's energy policy. Three new electricity decrees were announced in 2024. The decrees aim to promote metering bidirectional flows taken out of and fed into the grid, introduce conditions for certificates of origin issued by the Ministry for Energy Transition and Sustainable Development as well as enable energy service companies to conduct studies and implement energy efficiency mechanisms.

Morocco has suffered from consecutive years of drought, which continued in 2024. In 2023, in response to the droughts, a freshwater emergency plan was activated, which aims to increase the deployment of desalination plants, some of which are expected to start pumping water by the end of the forecast period. In late 2024, further planned seawater desalination projects were announced, including one targeting a capacity of up to 822 000 m^3 of drinking water per day. An increase in desalination plants would correspond to additional electricity demand. Desalination plants are an inflexible load on the electricity grid due to their need for constant water production and consistent electricity consumption. This inflexibility poses a challenge for integrating such loads into a grid with a large share of intermittent VRE.

Nigeria

Supply issues continued to constrain gas-fired generation, while distributed solar PV in rural areas saw robust growth

An estimated 70% of Nigerians had access to electricity in 2023, up from 50% a decade ago. But the gap between rural and urban areas remains stark: nearly 95% of residents in cities have access to electricity, compared to only 40% in rural areas. Electricity demand declined by around 6% in 2024, but we forecast that it will increase on average by more than 5% annually between 2025 and 2027.

Following the start of the Zungeru hydroelectric plant in April 2024, Nigeria now counts 28 grid-connected power plants, which increased the country's total installed capacity to 14 GW, compared to 12.6 GW in 2023. However, this growth in installed capacity did not suffice to compensate for the decrease of available capacity. In the first half of 2024, the average daily available capacity was 4.14 GW, slightly lower than the 4.54 GW recorded in 2023.

One factor explaining this discrepancy is the worsening of gas supply constraints, which have significantly impacted the operational performance of gas-fired plants. In 2024, gas accounted for 77% of the country's electricity generation, and we expect it to continue holding the majority share in the electricity mix with an estimated 2.4% annual growth in 2025-2027. Yet, lingering gas shortages remain a critical bottleneck. Renewables, mostly hydropower, account for the remaining on-grid generation, but solar PV is surging across the country, particularly as a distributed generation solution in rural areas.

Electricity tariffs in Nigeria remain below cost-reflective levels, making it difficult for power companies to cover production costs. This has led to the accumulation of significant debts owed to gas producers, resulting in reduced gas supply to electricity generation companies. In March 2024, the Nigerian government intervened by partially settling these debts to ease tensions and stabilise gas supply.

In the first half of 2024, several gas-fired plants saw their plant availability factor drop to under 5% due to limited gas supply. The consequent decrease in electricity output forced Nigerian power distribution companies to ration electricity supplies in some areas. In the second half of 2024, grid collapses became more common, with a significant increase in the total number for 2024 compared to three recorded in 2023 and six in 2022. Contributing factors include gas shortages, but also vandalism and ageing infrastructures.

The Minister of Power also commissioned five transformer installation projects under the Presidential Power Initiative, which are expected to enhance transmission wheeling capacity by 272 MW. The Rural Electrification Agency (REA) signed five MoUs with private developers for decentralised renewable energy (DRE) projects, including mini-grids and industrial power solutions, totalling 1.26 GW to boost rural access. Additionally, the REA signed an MoU with Husk Power to deploy 250 MW of DRE projects in rural and peri-urban areas. Nigerian company Geregu Power also signed an MoU with Siemens Energy to expand capacity of its Geregu gas power plant to 1.2 GW.

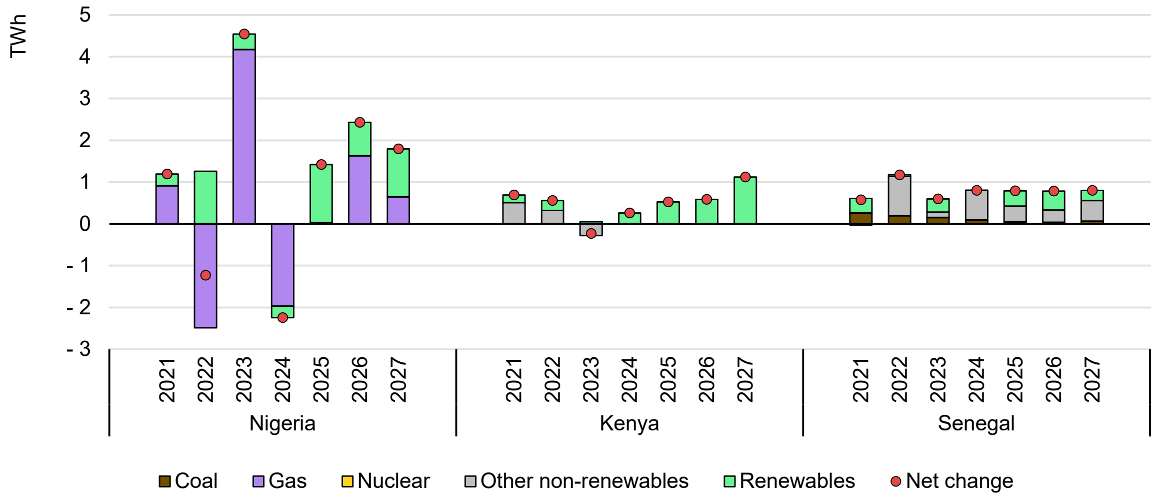
Power sector reforms were initiated, including creating local electricity markets and simplifying electricity tariffs

The Nigerian gas and power sectors have undergone various reforms in the past months, notably following the adoption of the Electricity Act 2023. With the aim of decentralising power generation and distribution, the Act empowered states to establish legislation to create local markets for generation and transmission of power to all areas within their boundaries. In 2024, several states exercised this new power by issuing orders to formally transfer regulatory oversight of their electricity markets from the Nigerian Electricity Regulatory Commission (NERC) to state-level regulatory bodies. The NERC also issued an order to establish an Independent System Operator for Nigeria. This new entity will take over all market and system operation contracts and obligations previously managed by the Transmission Company of Nigeria (TCN). If effectively implemented, this reform could mark a significant step forward in Nigeria's electricity sector liberalisation.

Building on these provisions, Lagos State is taking a major step forward by seeking to establish a distinct Lagos Electricity Market designed to operate independently of the national grid. The Lagos State Electricity Bill 2024 aims to set up a comprehensive framework for a sustainable and competitive electricity landscape in the state, with a particular emphasis on enhancing infrastructure, promoting renewable energy adoption and ensuring consumer protection.

Other recent reforms include an 11% increase in the domestic base price for natural gas for power generation companies, and an electricity tariff hike for Band A customers (highest tariff category), who are guaranteed 20 hours of electricity daily. This price adjustment reflects the government's effort to reduce reliance on state subsidies for electricity, particularly for higher-paying customer categories. This new initiative aims to address the estimated NGN 2.9 trillion (Nigerian naira) electricity subsidy in the 2024 fiscal year. The government plans to transition the entire power sector to a single, cost-reflective tariff band within the next three years.

Year-on-year change in electricity generation in Nigeria, Kenya and Senegal, 2021-2027



Notes: Other non-renewables includes oil, waste and other non-renewable sources. Data for 2025-2027 are forecast values.

Kenya

Clean energy sources make up 90% of the electricity generation mix, with new low-emissions projects planned

According to IEA analysis, Kenya is on track to achieve its Sustainable Development Goal 7 (SDG7) of universal access to electricity by 2030, with the access rate reaching 79% in 2023. Improvements can be attributed to the Last Mile Connectivity Project (LMCP), aimed at speeding up the electrification efforts, which has connected almost 750 000 households since its launch in 2015. Further, from 2022 to 2024, Kenya increased its power distribution lines by 2 600 km, representing 3.2% growth.

Electricity demand in Kenya rose by an estimated 3.2% annually from 2018-2024, and we forecast an annual increase of 6.5% during 2025-2027. We anticipate Kenya to continue to see strong growth in renewables, rising annually by 6% in the next three years. Wind and solar PV experienced the largest yearly generation growth from 2018-2024, at 63% and 34%, respectively, and they are expected to continue strong growth over the 2025-2027 period, albeit at lower rates, at 12% and 28%, respectively. Several wind and solar PV projects are currently under development, including a 42 MW solar PV project in the Seven Forks dam, which is expected to come online in 2027.

Geothermal power remains the largest source of electricity generation in Kenya, at 41% of total generation in 2024. Kenya estimates that it has about 7 000-10 000 MW of untapped geothermal energy in its Rift Valley region. The Geothermal Development Company (GDC) aims to develop 465 MW of geothermal capacity in the Menengai steam field over five phases, providing electricity to half a million households. The Menegai III plant (35 MW) began operations in 2023, and Menengai II (35 MW) is slated for completion by 2025. Additionally, Kenya aims to develop 800 MW in the Baringo Silali geothermal block, and to rehabilitate some of its old geothermal power plants to increase output.

Several large hydropower plants are expected to come online in 2031-2032, including the High Grand Falls Power Station with a capacity of 700 MW. Kenya has a high potential for small-scale hydro, estimated at 3 000 MW, but only 15 MW is currently connected to the national grid.

Kenya aims to diversify its electricity supply, and plans to start the construction of its first nuclear power plant in 2027, expected online in 2034. An interconnector between Kenya and Tanzania is set for completion at the end of 2024, seeking to eventually connect to Zambia and join the Eastern Africa Power Pool (EAPP) to the Southern African Power Pool (SAPP) by November 2025.

Kenya faces high network losses, estimated at 23% in the 2023/2024 financial year, with about half due to technical losses from transmission and distribution lines. In the 2022/2023 financial year, Kenya Power posted a 46% rise in cases of transformer vandalism. The government proposed a Critical Infrastructure Protection Bill (2024), which is still under review, to enhance security of critical infrastructure installations.

Senegal

Renewables are expected to meet more than 40% of the demand growth out to 2027

Access to electricity in Senegal has steadily improved over recent years, though challenges remain. As of 2023, an estimated 82% of the population had access, up from 61% in 2013. Urban areas continue to see higher connectivity rates, with nearly all residents in cities having access, compared to just 62% in rural regions. The government has aligned the target to bridge this gap with SDG7, aiming for universal access by 2030.

Electricity demand grew by an estimated 10% in 2024 and is forecast to average 8.6% annually in 2025-2027. In 2022, total installed power capacity amounted to 1.79 GW, with 85% of the electricity generated by fossil fuels. Rising prices of imported heavy fuel oil, on which Senegal relies, prompted the national utility Senelec to raise electricity prices in 2023 by removing certain subsidies. The government has committed to reduce these subsidies to 1% of its GDP by 2025. The government is currently working on an investment plan for the Just Energy Transition Partnership, signed in 2023, which sets a target of 40% of renewable installed capacity (around 1 GW) by 2030.

The government's gas-to-power strategy, which seeks to leverage domestic gas resources to improve energy security and reduce reliance on imports, gained traction in 2024 with the commissioning of the 120 MW Cap des Biches gas-fired power plant. Another 255 MW combined cycle gas-fired power plant in Saint Louis led by Turkish power producer Aksa Energy started development in 2024 and the company plans to begin commercial production in 2026. Senelec is also negotiating to convert existing power stations to gas. To supply gas to these new facilities, Senelec is exploring gas supply options, which could provisionally be LNG and later domestic sources from the Yakaar-Téranga and GTA projects.

Several projects to enhance Senegal's transmission network are also underway. In August 2024, the Ndindy 225/30 kV substation was inaugurated in Touba, a growing city in the central region of the country. This is part of Senelec's efforts to modernise and improve the grid to enhance reliability and quality of service, as well as to extend electricity services to broader regions of the country. Additional projects include the construction of 225/30 kV substations in Linguère and Ndioum, set for completion by 2025. Senelec also has plans to deploy underground high- and extra-high voltage lines, transformer substations, and advanced network management systems.

Annexes

Summary tables

Regional breakdown of electricity demand, 2022-2027

TWh	2022	2023	2024	2027	Growth rate 2022-2023	Growth rate 2023-2024	CAAGR 2025-2027
Africa	754	767	792	922	1.7%	3.3%	5.2%
Americas	6 369	6 342	6 481	6 909	-0.4%	2.2%	2.2%
of which United States	4 332	4 253	4 336	4 593	-1.8%	2.0%	1.9%
Asia Pacific	13 840	14 585	15 452	17 983	5.4%	5.9%	5.2%
of which China	8 678	9 293	9 935	11 803	7.1%	6.9%	5.9%
Eurasia	1 309	1 323	1 369	1 450	1.1%	3.5%	1.9%
Europe	3 680	3 576	3 643	3 850	-2.8%	1.9%	1.9%
of which European Union	2 663	2 576	2 613	2 752	-3.3%	1.4%	1.7%
Middle East	1 225	1 260	1 300	1 430	2.8%	3.2%	3.2%
World	27 178	27 854	29 038	32 542	2.5%	4.3%	3.9%

Notes: Data for 2024 are preliminary; 2025-2027 are forecasts. Differences in totals are due to rounding. CAAGR = Compounded average annual growth rate. For the CAAGR 2025-2027 reported, end of 2024 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, 2022-2027

TWh	2022	2023	2024	2027	Growth rate 2022-2023	Growth rate 2023-2024	CAAGR 2025-2027
Nuclear	2 686	2 742	2 840	3 036	2.1%	3.5%	2.3%
Coal	10437	10 611	10 704	10 674	1.7%	0.9%	-0.1%
Gas	6 525	6 608	6 777	6 889	1.3%	2.6%	0.6%
Other non-renewables	927	891	860	717	-3.9%	-3.5%	-5.9%
Total renewables	8 543	8 969	9 848	13 250	5.0%	9.8%	10.4%
Total Generation	29 119	29 822	31 029	34 566	2.4%	4.0%	3.7%

Mt CO_2	2022	2023	2024	2027	Growth rate 2022-2023	Growth rate 2023-2024	CAAGR 2025-2027
Total emissions	13 490	13 680	13 822	13 776	1.4%	1.0%	-0.1%

Breakdown of Asia Pacific electricity supply and emissions, 2022-2027

TWh	2022	2023	2024	2027	Growth rate 2022-2023	Growth rate 2023-2024	CAAGR 2025-2027
Nuclear	747	791	820	986	6.0%	3.7%	6.3%
Coal	8 230	8 721	8 894	9 041	6.0%	2.0%	0.5%
Gas	1 481	1 479	1 541	1 615	-0.1%	4.2%	1.6%
Other non-renewables	215	195	188	153	-9.4%	-3.3%	-6.6%
Total renewables	3 938	4 185	4 786	6 986	6.3%	14.4%	13.5%
Total Generation	14 611	15 371	16 229	18 781	5.2%	5.6%	5.0%

Mt CO_2	2022	2023	2024	2027	Growth rate 2022-2023	Growth rate 2023-2024	CAAGR 2025-2027
Total emissions	8 645	9 105	9 296	9 456	5.3%	2.1%	0.6%

Breakdown of Americas electricity supply and emissions, 2022-2027

TWh	2022	2023	2024	2027	Growth rate 2022-2023	Growth rate 2023-2024	CAAGR 2025-2027
Nuclear	924	935	939	944	1.1%	0.4%	0.2%
Coal	1 016	844	813	729	-17.0%	-3.6%	-3.6%
Gas	2 220	2 373	2 478	2 371	6.9%	4.4%	-1.5%
Other non-renewables	191	180	175	157	-5.7%	-2.8%	-3.5%
Total renewables	2 488	2 482	2 582	3 225	-0.3%	4.0%	7.7%
Total Generation	6 840	6 813	6 986	7 426	-0.4%	2.5%	2.1%

Mt CO_2	2022	2023	2024	2027	Growth rate 2022-2023	Growth rate 2023-2024	CAAGR 2025-2027
Total emissions	2 015	1 910	1 919	1 781	-5.2%	0.4%	-2.4%

Breakdown of Europe electricity supply and emissions, 2022-2027

TWh	2022	2023	2024	2027	Growth rate 2022-2023	Growth rate 2023-2024	CAAGR 2025-2027
Nuclear	750	751	810	823	0.1%	7.8%	0.5%
Coal	671	540	478	363	-19.5%	-11.4%	-8.8%
Gas	789	677	626	518	-14.2%	-7.6%	-6.1%
Other non-renewables	96	83	76	71	-13.2%	-8.7%	-2.5%
Total renewables	1 596	1 757	1 885	2 307	10.1%	7.3%	7.0%
Total Generation	3 902	3 809	3 875	4 081	-2.4%	1.7%	1.7%

Mt CO_2	2022	2023	2024	2027	Growth rate 2022-2023	Growth rate 2023-2024	CAAGR 2025-2027
Total emissions	1 014	838	750	599	-17.4%	-10.5%	-7.2%

Breakdown of Eurasia electricity supply and emissions, 2022-2027

TWh	2022	2023	2024	2027	Growth rate 2022-2023	Growth rate 2023-2024	CAAGR 2025-2027
Nuclear	226	218	216	221	-3.5%	-1.1%	0.8%
Coal	267	270	276	291	1.2%	2.3%	1.7%
Gas	676	693	710	761	2.5%	2.5%	2.3%
Other non-renewables	15	16	16	14	3.0%	1.3%	-4.5%
Total renewables	273	277	298	318	1.3%	7.6%	2.2%
Total Generation	1 457	1 474	1 516	1 605	1.2%	2.8%	1.9%

Mt CO_2	2022	2023	2024	2027	Growth rate 2022-2023	Growth rate 2023-2024	CAAGR 2025-2027
Total emissions	558	570	584	618	2.0%	2.5%	1.9%

Breakdown of Middle East electricity supply and emissions, 2022-2027

TWh	2022	2023	2024	2027	Growth rate 2022-2023	Growth rate 2023-2024	CAAGR 2025-2027
Nuclear	29	39	47	50	35.8%	20.0%	2.0%
Coal	18	14	10	5	-21.8%	-29.8%	-18.3%
Gas	982	983	1 011	1 180	0.0%	2.9%	5.3%
Other non-renewables	344	360	348	265	4.5%	-3.2%	-8.6%
Total renewables	44	57	77	113	30.1%	34.0%	13.8%
Total Generation	1 417	1 452	1 492	1 613	2.5%	2.8%	2.6%

Mt CO_2	2022	2023	2024	2027	Growth rate 2022-2023	Growth rate 2023-2024	CAAGR 2025-2027
Total emissions	782	791	792	813	1.1%	0.2%	0.9%

Breakdown of Africa electricity supply and emissions, 2022-2027

TWh	2022	2023	2024	2027	Growth rate 2022-2023	Growth rate 2023-2024	CAAGR 2025-2027
Nuclear	10	8	8	13	-17.1%	4.2%	16.1%
Coal	236	223	233	245	-5.5%	4.7%	1.6%
Gas	376	402	411	444	6.8%	2.2%	2.6%
Other non-renewables	66	58	57	57	-11.9%	-1.0%	-0.2%
Total renewables	203	212	221	301	4.2%	4.5%	10.8%
Total Generation	891	903	931	1 060	1.3%	3.0%	4.4%

Mt CO_2	2022	2023	2024	2027	Growth rate 2022-2023	Growth rate 2023-2024	CAAGR 2025-2027
Total emissions	475	467	481	509	-1.8%	3.0%	1.9%

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.

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).

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.

Abbreviations and acronyms

AEMO	Australian Energy Market Operator
AI	artificial intelligence
AWS	Amazon Web Services
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

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