Renewables

2025

Analysis and forecast to 2030

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Abstract

Renewables 2025 is the IEA's main annual report on the sector. It presents the latest forecasts and analysis, based on recent policy and market developments, while also exploring key challenges and opportunities facing the sector.

This year's edition provides forecasts for the deployment of renewable energy technologies in electricity, transport and heat through 2030. It also examines notable developments in key areas of the sector, including policy changes, manufacturing trends, and the financial health of different parts of the industry.

Acknowledgements, contributors and credits

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The report benefited from analysis, drafting and input from multiple colleagues. The lead authors of the report were, Yasmina Abdelilah, Ana Alcalde Báscones, Vasilios Anatolitis-Pelka, Heymi Bahar, Marcus Bockhold, Piotr Bojek, François Briens, Trevor Criswell, Martina Lyons, Jeremy Moorhouse, Hunor Papolczi, and Laura Marí Martínez, who was also responsible for data management.

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Countries

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Questions or comments?

Please write to us at IEA-REMR@iea.org

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Executive summary

Renewables' global growth, driven by solar PV, remains strong amid rising headwinds

Global renewable power capacity is expected to double between now and 2030, increasing by 4 600 gigawatts (GW). This is roughly the equivalent of adding China, the European Union and Japan's power generation capacity combined to the global energy mix. Solar PV accounts for almost 80% of the global increase, followed by wind, hydropower, bioenergy and geothermal. In more than 80% of countries worldwide, renewable power capacity is set to grow faster between 2025 and 2030 than it did over the previous five-year period. However, challenges including grid integration, supply chain vulnerabilities and financing are also increasing.

The increase in solar PV capacity is set to more than double over the next five years, dominating the global growth of renewables. Low costs, faster permitting and broad social acceptance continue to drive the accelerating adoption of solar PV. Wind power faces supply chain issues, rising costs and permitting delays – but global capacity is still expected to nearly double to over 2 000 GW by 2030 as major economies like China and the European Union address these challenges. Hydropower is set to account for 3% of new renewable power additions to 2030. The faster growth of pumped storage plants between 2025-30 leads to a much greater increase in hydropower compared with the previous five years. In 2030, annual geothermal capacity additions are expected to reach a historic high, triple the 2024 increase, driven by growth in the United States, Indonesia, Japan, Türkiye, Kenya and the Philippines.

The forecast for growth in global renewable power capacity is revised down slightly, mainly due to policy changes in the United States and China. The renewable energy growth forecast for the 2025-2030 period is 5% lower compared with last year's report, reflecting policy, regulatory and market changes since October 2024. The forecast for the United States is revised down by almost 50%. This reflects several policy changes, including the earlier phase out of federal tax credits, new import restrictions, the suspension of new offshore wind leasing and restricting the permitting of onshore wind and solar PV projects on federal land. China's shift from fixed tariffs to auctions is impacting project economics and lowering growth expectations. Nonetheless, China continues to account for nearly 60% of global renewable capacity growth and is on track to reach its recently announced 2035 wind and solar target five years ahead of schedule, extending its track record of early delivery.

The outlook for renewables is more positive in India, Europe and most emerging and developing economies compared with last year's forecast. India's renewable expansion is driven by higher auction volumes, new support for rooftop solar projects, and faster hydropower permitting. The country is on track to meet its 2030 target and become the second-largest growth market for renewables, with capacity set to rise by 2.5 times in five years. In the European Union, the growth forecast has been revised upwards slightly as a result of higher-than expected utility-scale solar PV capacity installations, driven by strong corporate power purchase agreement (PPA) activity in Germany, Spain, Italy and Poland. This offsets a weaker outlook for offshore wind. The Middle East and North Africa forecast has been revised up by 25%, the biggest regional upgrade, due to rapid solar PV growth in Saudi Arabia. In Southeast Asia, solar PV and wind deployment is accelerating, with more ambitious targets and new auctions.

Global renewable power capacity is expected to reach 2.6 times its 2022 level by 2030 but fall short of the COP28 tripling pledge. In the United Arab Emirates in November 2023, nearly 200 countries agreed on the goal of tripling global renewable capacity by 2030. This target can still be brought within reach if countries adopt enhanced policies to bridge gaps in both ambition and implementation. The accelerated case in this report sees global renewable capacity reaching 2.8 times its 2022 level by 2030 if countries minimise policy uncertainties, reduce permitting timelines, increase investment in grid infrastructure, expand flexibility to facilitate integration of variable renewables, and de-risk financing.

Wind and solar manufacturers struggle financially, but appetite from developers and buyers remains strong

Major solar PV and wind manufacturers have reported large losses despite surging global installations. The financial sustainability of equipment manufacturers remains a major issue. In China, solar PV prices are down over 60% since 2023 due to supply glut of modules and competition for market share. This has reduced the margins of the largest manufacturers to -10% with cumulative losses reaching almost USD 5 billion since the beginning of 2024. Wind manufacturers outside China continue to struggle financially, reporting cumulative losses of USD 1.2 billion last year.

Despite challenges, renewable developers have either increased or maintained their capacity deployment targets for 2030 since last year. The assessment in this report shows that one-fifth of surveyed large renewables developers increased their deployment goals, while three-quarters kept them at similar levels to last year. Corporate PPAs, utility contracts and merchant plants are also a major driver, accounting for 30% of global renewable capacity expansion to 2030, double the share in last year's forecast. Both developers and buyers are benefitting from lower solar PV costs.

The offshore wind industry faces multiple challenges, with forecast growth over the next five years revised down by more than 25%. Several developers reduced their 2030 deployment targets. Lower expectations are driven by the policy shift in the United States and project cancellations and delays in Europe, Japan and India due to higher costs and supply chain challenges.

Amid diversification efforts, the renewable sector faces supply chain dependencies and integration challenges

Solar PV supply chains and rare earth elements for wind turbines will remain highly concentrated in a single country, highlighting supply chain security risks. Overcapacity, low prices, trade barriers and regulatory shifts have slowed new investment in solar PV supply chains inside China, while manufacturing capacity outside of China is expanding. However, supply chain concentration for key production segments will remain above 90% in 2030, similar to today's level. In addition, China dominates the mining (60%), and refining (90%) of rare earth elements used in magnets for large onshore and offshore wind turbines. In addition, around 90% of rare earth magnet production is also located in China. Despite diversification efforts, mining and refining is expected to remain highly concentrated through 2030.

Growing shares of wind and solar PV are transforming electricity markets, increasing integration challenges. By 2030, variable renewables will generate almost 30% of global electricity supply, double today's level. This calls for a rapid increase in power system flexibility and grid investment in an increasing number of countries. Curtailment levels have been rising in many markets including China, Germany, Brazil, Chile, the UK and Ireland. The number of hours with negative prices has surged across multiple countries, coinciding with peak solar generation. Curtailment and negative prices signal a lack of flexibility in electricity systems and/or a mismatch between supply and demand at certain times. Growing electrification, and demand-side flexibility (e.g. smart EV chargers or heat pumps), storage (short and long term) and dispatchable power plants will be increasingly needed to integrate wind and solar PV securely and cost-effectively. More countries are introducing policies to boost dispatchability and storage, with over 10 of them launching firm-capacity auctions for solar PV and wind over the last five years.

The deployment of renewables has already reduced fuel import needs significantly in many countries, enhancing energy diversification and security. Since 2010, the world added around 2 500 GW of non-hydro renewable power capacity, about 80% of which was installed in countries that rely on fossil fuel imports. Without these renewable additions, cumulative global imports of coal and natural gas in these countries would have been 45% higher in 2023. As a result, countries have reduced coal imports by 700 million tonnes and natural gas imports by 400 billion cubic metres, saving an estimated USD 1.3 trillion since 2010.

Renewables use in heat and transport continues to grow, but their share of demand is set to rise only slightly

Renewables are set to increase their share of energy demand in the transport sector from 4% today to 6% in 2030. The use of renewable electricity to power electric vehicles accounts for nearly half of the growth, concentrated mainly in China and Europe. Liquid biofuels make up most of the remainder, with growth concentrated in Brazil, followed by Europe, Indonesia, India and Canada.

Renewables are forecast to account 18% of global heat demand by 2030, up from 14% today. An expected 42% increase in consumption of heat from renewables over the next five years is driven largely by renewable electricity use in industry and buildings, as well as by rising use of bioenergy.

Chapter 1. Renewable electricity

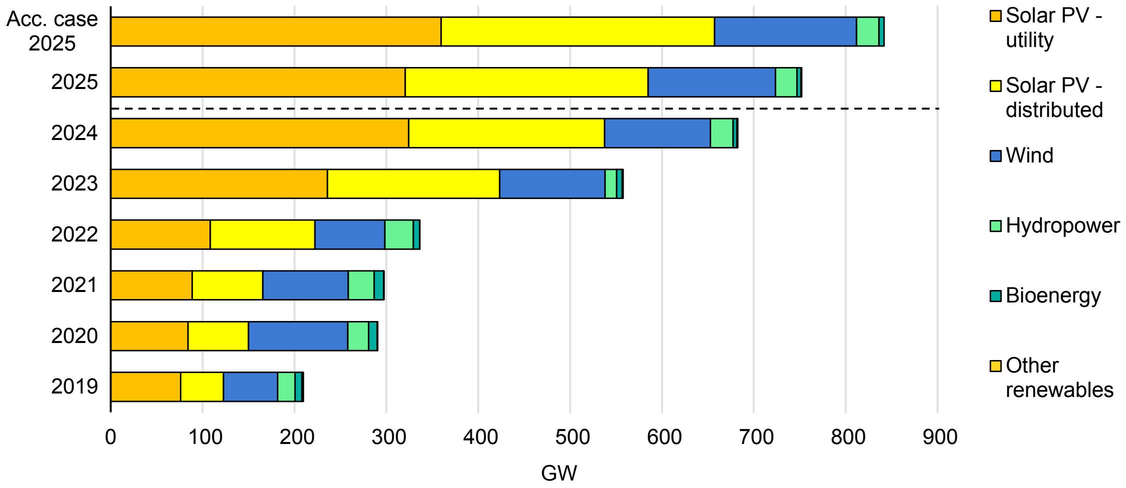
Global forecast summary

2025 will be another record year for renewables

In 2024, global renewable electricity capacity additions grew 22% to reach nearly 685 GW – a new all-time high. Despite increasing policy uncertainty and ongoing regulatory challenges, 2025 is expected to be another record year, with capacity additions reaching over 750 GW in the main case and 840 GW in the accelerated case.

Solar PV continues to make up the majority of growth, with annual additions expanding further in 2025, though at a slower rate. It is expected to account for nearly 80% of the total global renewable electricity capacity increase, maintaining its dominant share from 2024. While utility-scale solar PV additions remain stable in 2025, expansion is expected for distributed solar PV applications.

Renewable electricity capacity additions by technology, 2019-2025



Notes: Capacity additions refer to net additions. Historical and forecast solar PV capacity may differ from previous editions of the renewable energy market report. Solar PV data for all countries have been converted to DC (direct current), increasing capacity for countries reporting in AC (alternating current). Conversions are based on an IEA survey of more than 80 countries and interviews with PV industry associations. Solar PV systems work by capturing sunlight using photovoltaic cells and converting it into DC electricity, which is then usually converted using an inverter, as most electrical devices and power systems use AC. Until about 2010, AC and DC capacity in most PV systems were similar, but with developments in PV system sizing, these two values may now differ by up to 40%, especially for utility-scale installations. Solar PV and wind additions include capacity dedicated to hydrogen production.

Wind additions remained stable last year but are anticipated to increase to 139-155 GW in 2025, accounting for 18% of overall forecast growth. Onshore wind is expected to break another record, with 124 GW becoming operational in 2025 as uptake in the People's Republic of China (hereafter, "China"), the United States, the European Union and India increases. Offshore wind capacity is forecast to expand 15 GW, a 60% year-on-year increase driven by China's acceleration.

Having almost doubled in 2024, hydropower growth is expected to be 5% slower this year, with installations reaching 23-24 GW, mainly from the commissioning of large projects in China and India. Bioenergy for power additions amounted to only 4.2 GW in 2024, the lowest level since 2008 as less new capacity is being installed in advanced economies and growth is slowing in emerging markets.

Meanwhile, geothermal power additions are expected to increase for the second year in row in 2025 (to almost 0.45 GW), with capacity coming online in Indonesia, the Philippines, the Republic of Türkiye (hereafter, "Türkiye") and the United States, mainly from conventional projects. However, multiple large-scale enhanced geothermal projects are under construction in the United States and are expected to become operational in 2026 and 2027.

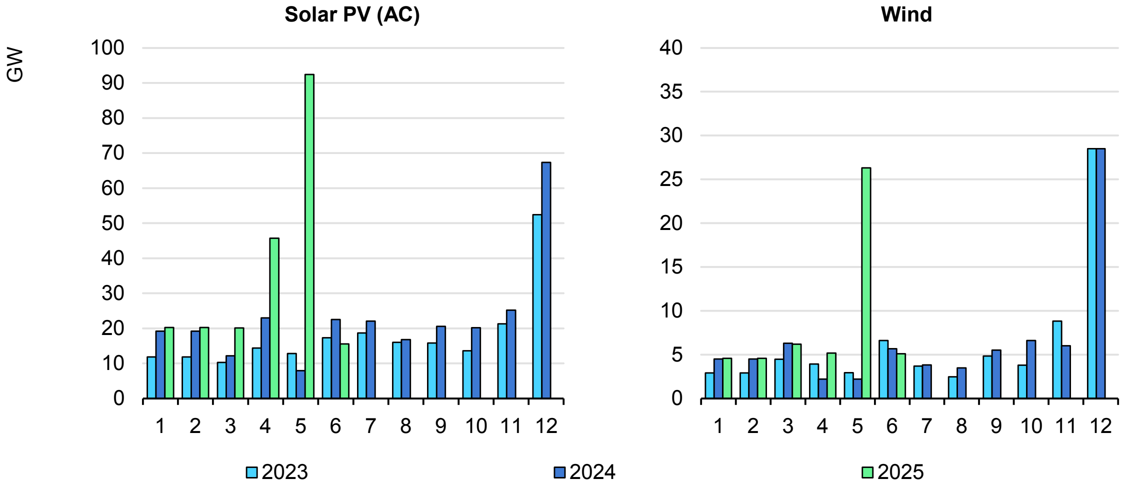
China's policy change led to an unprecedented solar PV and wind boom in the first half of 2025, but the pace of expansion in the second half remains uncertain

China's shift from long-term fixed tariffs to an auction-based contract-for-difference system is a key uncertainty for global renewable capacity growth in 2025 and beyond. The goal of the new policy is to achieve market-driven growth for renewables and facilitate their grid integration. Under the previous policy, wind and solar PV projects had access to 15-20 years of stable, guaranteed revenues at coal benchmark prices, providing strong revenue certainty.

This policy ended on 31 May 2025, prompting a rush by developers to commission projects before the deadline. As a result, solar PV (AC) additions in China surged to 93 GW in May 2025 – 12 times higher than in May 2024 – followed by an 85% drop to 15.5 GW in June. Wind power expansion followed a similar pattern, with additions jumping to over 26.5 GW in May before falling back to 5 GW in June.

Given the rapid pace of deployment in the first half of the year, our forecast projects a more moderate increase in wind and solar PV installations in the second half of 2025. Nevertheless, China's renewable capacity additions are expected to set another record, reaching almost 465 GW in 2025 under the main case. The accelerated case indicates even greater potential (509 GW), reflecting the uncertainties associated with recent policy shifts.

Monthly solar PV and wind capacity additions in China, 2023-2025



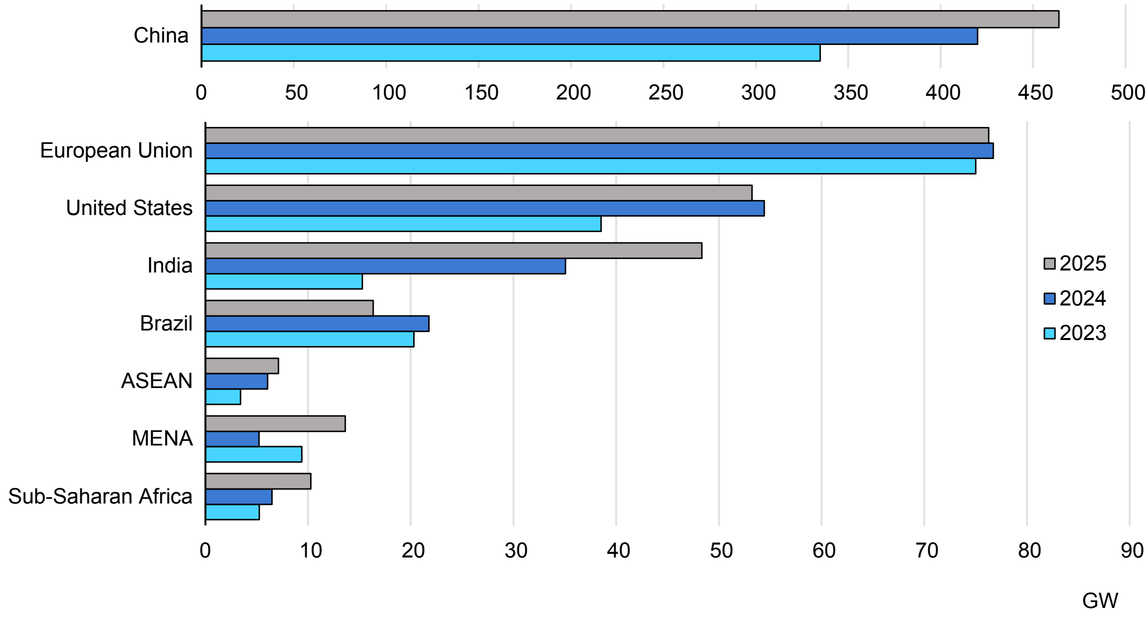
Source: China's National Energy Administration (NEA) monthly power capacity statistics.

In the European Union, annual capacity additions are expected to decline 1% in 2025 compared with 2024. In response to the energy crisis, capacity additions between 2021 and 2023 more than doubled to nearly 75 GW as countries aimed to reduce natural gas imports from the Russian Federation (hereafter, "Russia") followed the invasion of Ukraine. However, growth slowed last year and is expected to remain stable this year, with some differences across countries. In Germany and Spain, capacity additions are likely to grow slightly as increased wind power offsets a drop in distributed solar PV. In Italy and Poland, expansion is expected to slow, while in France both wind and solar PV capacity continue to increase.

Renewable capacity additions in the United States rose 40% from 2023 to 2024, mainly reflecting rapid increases in solar PV. Stable growth is expected in 2025, with slightly lower solar PV expansion and wind capacity on the rise from projects that qualified for tax credits before recent policy changes. Thanks to easing supply chain challenges, India continues to break records for solar PV installations each year, as the country has a considerable amount of awarded capacity in its project pipeline.

In Brazil, capacity additions are set to decline in 2025 for the first time in five years, as reduced net metering incentives slow growth. Meanwhile, in sub-Saharan Africa and the ASEAN region (Association of Southeast Asian Nations), major new solar PV and wind projects are expected to become operational in 2025, significantly boosting renewable capacity additions in both regions.

Renewable electricity capacity additions by country/region, 2023-2024



Notes: ASEAN = Association of Southeast Asian Nations. MENA = Middle East and North Africa.

Renewable capacity will continue to grow strongly until 2030, but the annual deployment trajectory will not be smooth

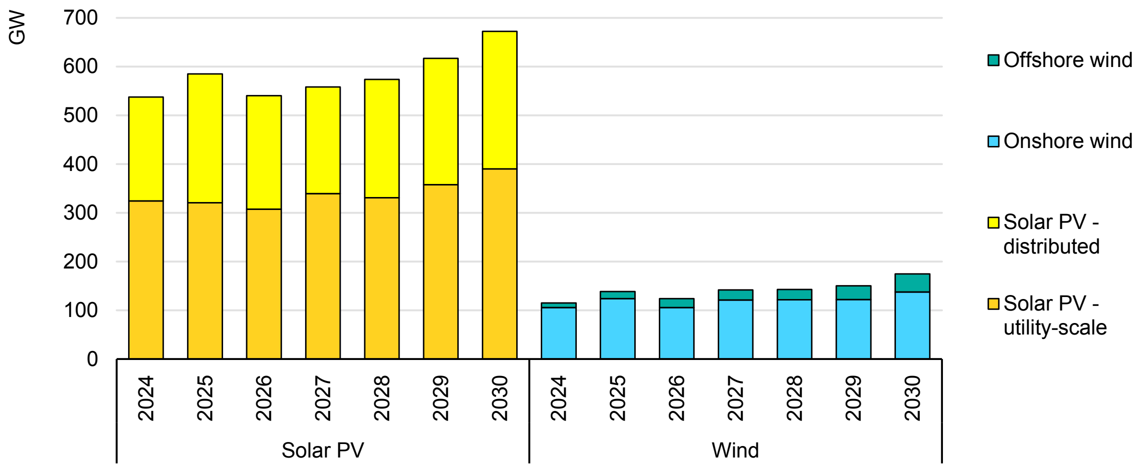
In the main case, global annual renewable capacity additions rise from 683 GW in 2024 to almost 890 GW in 2030. Solar PV and wind account for 96% of all renewable capacity additions through 2030 because they are the most affordable options to add new capacity in almost every country in the world, and policies in more than 130 countries continue to support them.

Because of commissioning deadlines, recent policy changes are expected to influence the annual-addition profiles of solar PV and wind capacity over the forecast period. Following record expansion in 2025, annual increases for both are expected to decline, primarily due to slowdowns in China and the United States linked to evolving policy timelines.

For China, 2026 is expected to be a transitional year following the rush by developers to meet prior policy deadlines before implementation of the new auction policy. Uncertainties regarding auction design and contract-for-difference arrangements at the provincial level are expected to delay some project developments, as investors adapt to the new structures and assess profitability within the recently established wholesale markets.

In the United States, solar PV and wind projects need to be commissioned by the end of 2027 to qualify for tax credits under the new policy framework. This requirement is expected to result in a relatively sparse project pipeline in 2026, as developers focus on meeting the 2027 deadline. Following expiration of the tax credit, annual solar PV additions decline in 2028 before gradually recovering thanks to the “safe harbour” rules that provide a four-year completion period for projects qualifying for tax credits before July 2026. In contrast, China is projected to experience rapid recovery starting in 2027, which will drive global solar PV and wind capacity additions upwards through 2030.

Solar PV and wind capacity additions by segment, main case, 2024-2030

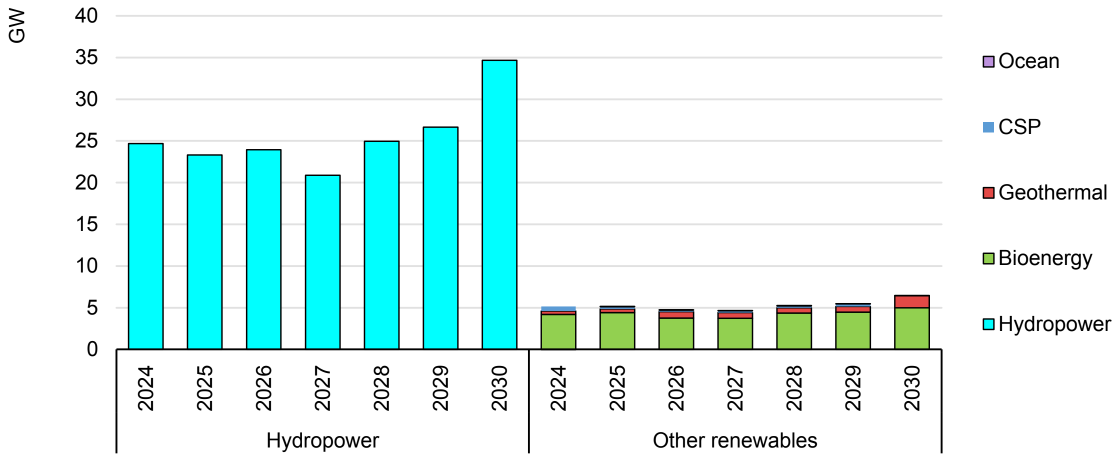


Despite rising demand for greater grid flexibility, dispatchable renewables are projected to make up only 4% of new renewable capacity additions

Annual capacity additions of hydropower, bioenergy, geothermal, CSP and ocean energy are expected to range from 25 GW to 41 GW over the forecast period. These renewable technologies are dispatchable and, along with batteries, they can provide the flexibility power systems need as variable renewable energy shares increase rapidly. Hydropower additions are highly volatile as commissioning deadlines are reached for large projects in emerging markets and developing countries. These plants contribute 21-35 GW annually over 2025-2030, with almost 90% of the growth in emerging and developing economies – mainly in China, Africa and Asia, with a smaller amount in Latin America.

In 2030, annual geothermal capacity additions are expected to break a new record with almost 1.5 GW becoming operational, tripling the 2024 increase. Both conventional and advanced geothermal projects come online in multiple countries, including the United States, Japan, Indonesia, the Philippines, Kenya and Türkiye.

Hydropower, bioenergy, geothermal, CSP and ocean energy capacity additions, main case, 2024-2030



Note: CSP = concentrated solar power.

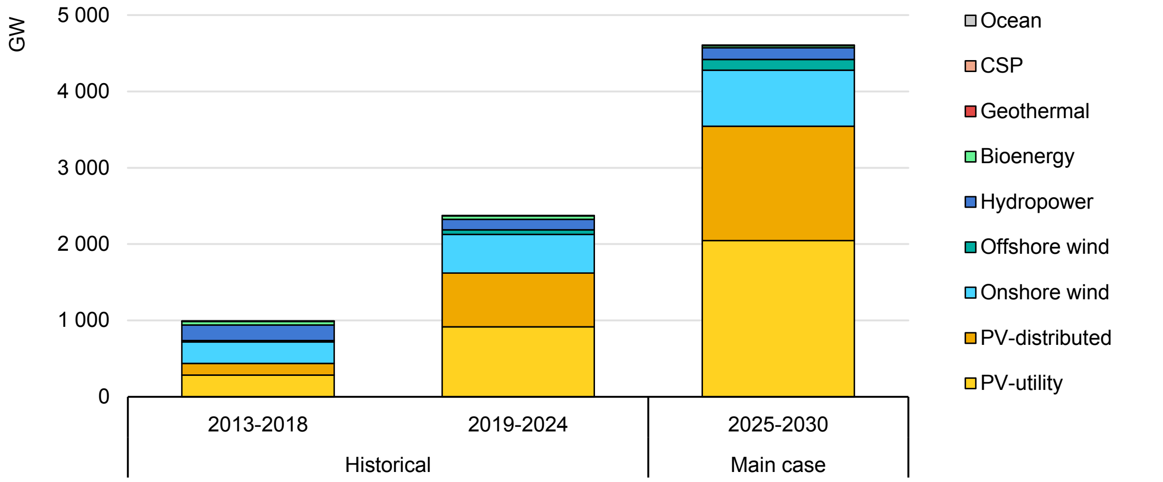
Renewable electricity additions for 2025-2030 total 4 600 GW – equal to the combined installed power capacity of China, the European Union and Japan

Globally, renewable power capacity is projected to increase almost 4 600 GW between 2025 and 2030 – double the deployment of the previous five years (2019-2024) – driven by solar PV. Growth in utility-scale and distributed solar PV more than doubles, representing nearly 80% of worldwide renewable electricity capacity expansion. Low module costs, relatively efficient permitting processes and broad social acceptance drive the acceleration in solar PV adoption.

Distributed solar PV applications (residential, commercial, industrial and off-grid projects) account for 42% of the overall PV expansion. Higher retail electricity prices following the energy crisis, along with strong policy support, have encouraged individuals and businesses to install solar PV systems with the aim of reducing their electricity bills. The use of distributed solar PV applications with storage units is also growing in countries that have an unreliable electricity grid. In South Africa and Pakistan, for instance, uptake in commercial and large-scale off-grid solar PV systems is rising rapidly, improving electricity access.

Compared with 2019-2024, our forecast expects cumulative **onshore wind** capacity additions to increase 45% over 2025-2030, reaching 732 GW. Despite recent challenges concerning supply chain bottlenecks, inflation, and long permitting and grid connection wait times, we expect strong onshore wind expansion, as policies in both advanced and developing countries have partly addressed these barriers. Annual additions are expected to rise in Africa, the Middle East, ASEAN countries, Latin America and Eurasia – in addition to Europe and India.

Renewable electricity capacity growth by technology segment, main case, 2013-2030



Note: CSP = concentrated solar power.

Offshore wind capacity expansion is expected to reach 140 GW over the forecast period, more than doubling the growth of the previous five-year period. The annual offshore wind market expands from 9.2 GW in 2024 to over 37 GW by 2030, with China accounting for almost 50% of this increase. In Europe, the annual market is expected to approach 14.6 GW by 2030. Policy changes in the United States, macroeconomic pressures and supply chain challenges have raised costs and undermined project bankability in several European markets and Japan, resulting in undersubscribed auctions and project cancellations. As a result, we have revised the global offshore wind capacity forecast 27% downwards from last year.

Hydropower growth from 2025 to 2030 is expected to be slightly higher than during 2019-2024, with more than 154 GW of new capacity coming online. Annual additions of pumped-storage hydropower (PSH) capacity is forecast to double to 16.5 GW by 2030, driven by the growing need for flexibility and long-term storage. China leads with over 60% of all worldwide PSH growth over the forecast period. PSH expansion is also gaining speed in Europe (Spain and Austria), as rapid deployment of variable renewable energy systems is presenting integration challenges. Hydropower development is also gaining momentum in India, the ASEAN region and Africa.

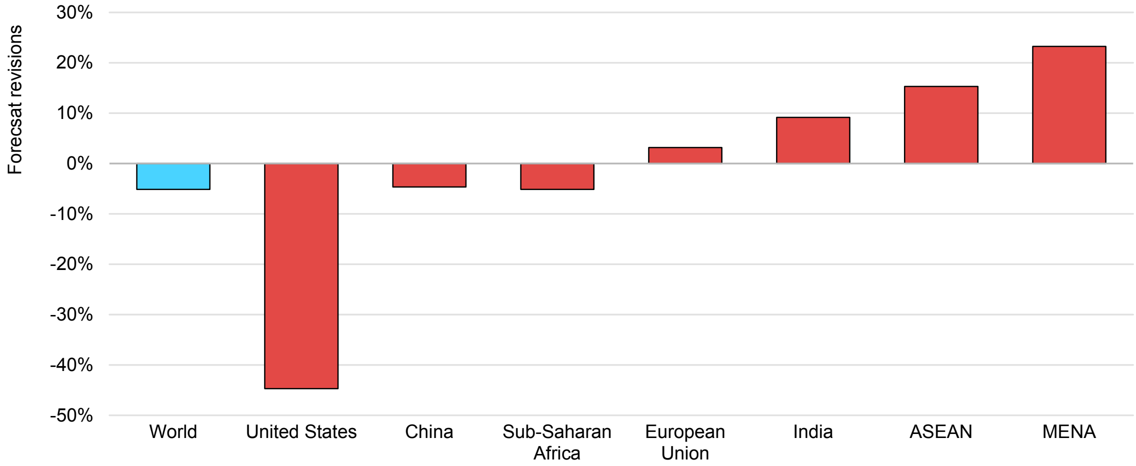
This year's forecast is a downward revision from 2024

Globally, we have lowered our renewable energy growth forecast for 2025-2030 by 5% compared to last year, to reflect policy, regulatory and market changes since October 2024. This revision means we now expect 248 GW less renewable capacity to be commissioned over 2025-2030.

For solar PV, wind and bioenergy for power, deployment has been revised downwards. Solar PV accounts for over 70% of the absolute reduction, mainly from utility-scale projects, while offshore wind demonstrates the largest relative decline in growth over the forecast period, decreasing 27%.

The US forecast is revised down by almost 50% across all technologies except geothermal. This reflects the earlier-than-expected phase-out of investment and production tax credits; new "foreign entities of concern" (FEOC) restrictions; and the executive order suspending offshore wind leasing and restricting the permitting of onshore wind and solar PV projects on federal land. Among all technologies, wind is impacted most, with both offshore and onshore capacity growth revised down by almost 60% (57 GW) over the forecast period. The forecast for solar PV capacity has been revised down by almost 40%. Although this is a smaller relative impact than for wind, it still means that nearly 140 GW less solar PV will be installed by 2030. Within solar PV, the largest relative impact is on distributed solar, particularly residential systems (revised down by almost 70%), which are most affected by the scheduled expiration of residential solar PV tax credits at the end of this year – well before tax credits for other technologies expire.

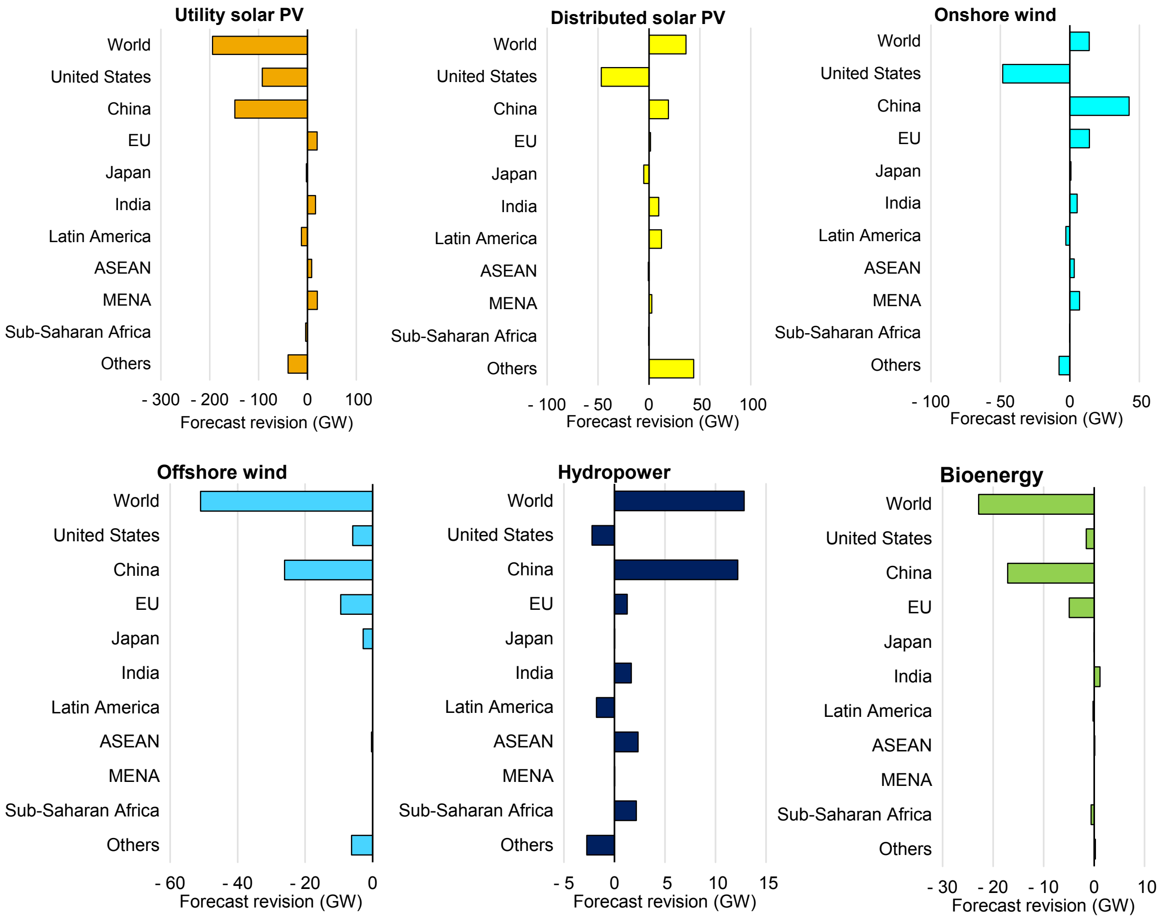
Renewable capacity expansion changes from *Renewables 2024* to *Renewables 2025* in selected countries/regions, 2025-2030



Note: ASEAN = Association of Southeast Asian Nations. MENA = Middle East and North Africa.

While China's 5% downward revision seems small in percentage terms, it is the second largest cut in absolute capacity (129 GW) following the United States. Since solar PV and onshore wind are the cheapest technology options to add new power generation in China, facilities were receiving 15- to 20-year contracts at provincial coal benchmark prices and very good returns on investments before June 2025. However, the government then introduced provincial competitive auctions with contracts for difference and requirements to participate in the newly established regional wholesale markets.

2025 forecast revisions by technology and country/region



Notes: ASEAN = Association of Southeast Asian Nations. MENA = Middle East and North Africa.

While this policy is a positive step towards market integration of renewables, it is expected to reduce profitability for investors, prompting us to revise our forecast slightly. For distributed solar PV, the Chinese government is also requiring commercial and industrial solar PV systems to increase self-consumption and sell their excess generation in the wholesale market.

In relative terms, China's new policy impacts offshore wind growth the most, as the cost of generation remains higher than for onshore wind and solar PV. However, we expect lost offshore wind investments to be shifted to onshore wind projects, for which the outlook is more optimistic because the government is making efforts to balance solar PV and wind deployment to facilitate grid integration. China's bioenergy forecast is also revised down by more than 50% due to a lack of specific support and a smaller waste-to-energy project pipeline.

Meanwhile, this year's EU forecast has been revised up slightly, mostly for utility-scale solar PV capacity in Germany, Spain, Italy and Poland. However, in many European markets lower retail electricity prices and reduced incentives following the energy crisis have made residential projects less economically attractive. Furthermore, supply chain challenges and higher costs have left multiple offshore wind auctions without bids, leading to several project cancellations and a 24% downwards forecast revision compared with last year.

We have revised India's forecast up by almost 10%, thanks to record auction capacity in 2024 for onshore wind and utility-scale solar PV; rapid recovery of the onshore wind industry; the introduction of a new rooftop-PV support scheme; and more efficient permitting for pumped-storage hydropower, which is driving faster growth. For the ASEAN region, the faster implementation of large hydropower projects and the introduction of more ambitious renewable energy goals and auction schemes has led to an upward forecast revision.

The forecast for the Middle East and North Africa is revised up 23%, driven by faster-than-expected developments in Saudi Arabia this year. Annual additions for 2025 are almost 9 GW – triple last year's 3 GW – after 4 GW of utility PV was commissioned one year ahead of schedule. In parallel, 15 GW of bilateral contracts were signed this year, including the first for onshore wind. As a result, growth was revised up by 20 GW to reflect the accelerated pace of deployment toward the 2030 target of 100–130 GW installed. The country aims for renewables to supply 50% of power, cutting oil burn (still 40% of generation) amid rising demand from cooling and desalination.

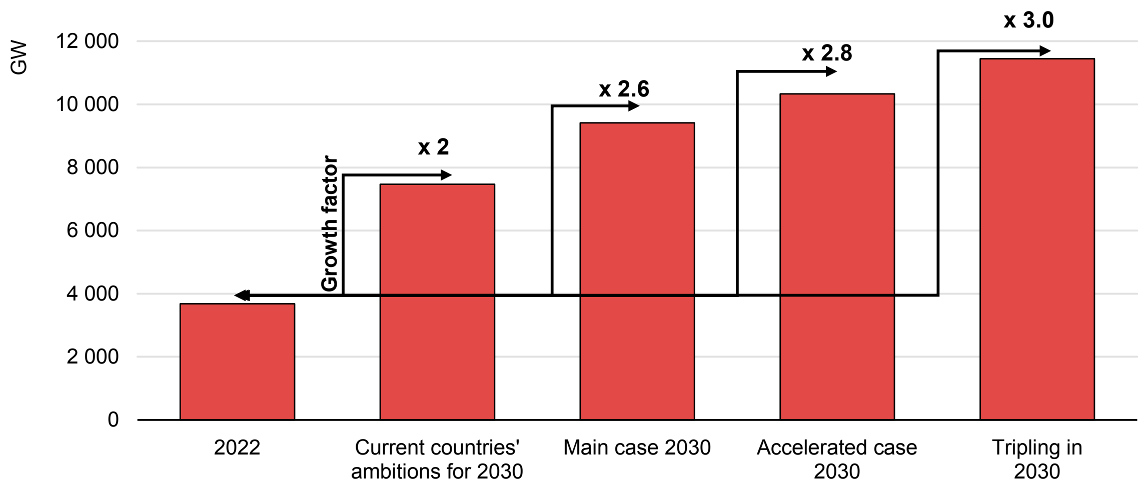
In Latin America, higher retail prices spur distributed solar PV system buildouts. However, growing curtailment risks for wind power in Brazil and for solar systems in Chile (where bilateral contracts drive deployment) have led to utility-scale project cancellations, impacting the forecast negatively. In sub-Saharan Africa, delays in auction implementation for solar PV and extended timelines for geothermal have led to a 5% downwards forecast revision.

Despite robust growth, a gap to global tripling remains

In 2023, nearly 200 countries at COP28 in Dubai pledged to honour the Paris goal of limiting warming to 1.5°C, agreeing for the first time on targets for 2030: tripling the use of renewable energy sources; doubling efficiency gains; cutting methane emissions; and advancing a just transition away from fossil fuels. In our main case, recent cost trends, current policies and market developments raise cumulative renewable capacity to 9 530 GW in 2030 – a 2.6-times increase from 2022. Nevertheless, the main case trajectory is not fully on track to triple global renewable capacity to around 11 500 GW, indicating that an ambition gap and implementation challenges continue to impede faster renewable power expansion.

Conversely, our accelerated case assumes that governments address key policy, grid integration, financing and permitting challenges in the short term to unlock almost 20% more capacity growth compared with the main case. Under this case, cumulative renewable electricity capacity reaches over 10 400 GW, bridging most of the gap to global tripling by 2030.

Renewable capacity growth 2022-2030 and the gap to global tripling



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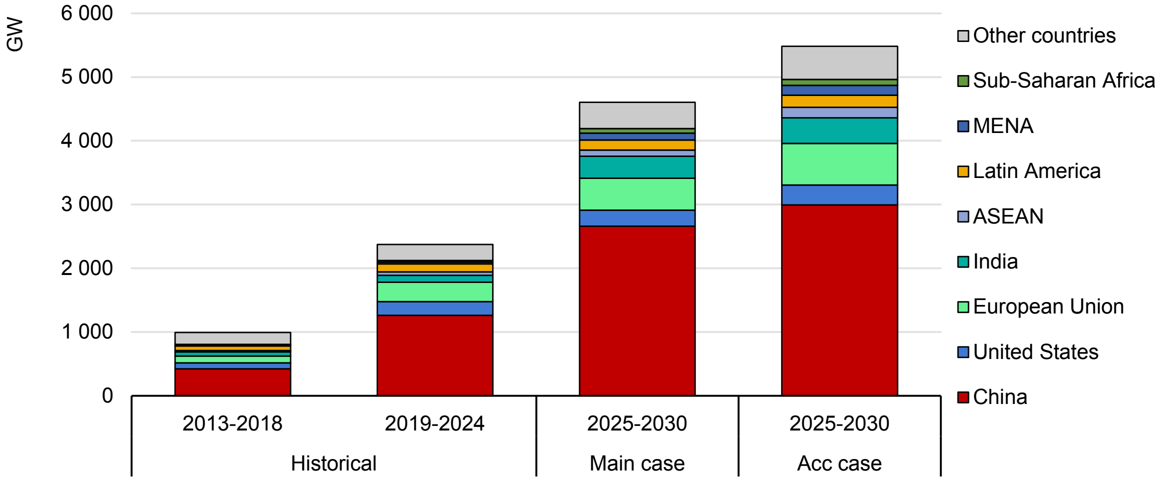
China's accelerated-case renewable energy growth is only 13% (334 GW) higher than in the main case. For China, the accelerated case assumes faster implementation of auctions and market reforms and quicker transmission and distribution grid expansion, enabling the deployment of additional renewable electricity projects in the pipeline. As the country maintains a large surplus of cost-competitive solar PV and wind manufacturing capacity, growth could be accelerated if renewable energy integration were improved and rooftop solar PV systems were installed more quickly.

Renewable capacity growth in the accelerated case by country/region



Notes: ASEAN = Association of Southeast Asian Nations. MENA = Middle East and North Africa.

For the **European Union**, the accelerated case demonstrates 30% upside potential, with cumulative renewable capacity reaching 1 411 GW by 2030 – on track to attain the REPowerEU target. However, this outcome relies heavily on faster solar PV growth, which would offset slower-than-expected progress in both onshore and offshore wind. To achieve more rapid wind expansion, the government would have to take five key policy actions: introduce additional auction volumes; provide revenue certainty to reduce market price risks; continue to increase system flexibility; reduce permitting wait times; and modernise grids to reduce connection queues.

India's renewable capacity growth could be 17% higher under the accelerated case, surpassing 2030 targets. Although there have been positive changes since 2022, many DISCOMs still face financial difficulties. If their financial health improves, state-level renewable portfolio obligations are enforced more strongly, and delays in signing power purchase agreements with auction-awarded projects are reduced, the accelerated case can be achieved. Although average variable renewable energy (VRE) penetration in India is expected to remain relatively low in 2030 owing to electricity demand growth, the geographical concentration of generation in several states (Rajasthan, Gujarat, Tamil Nadu, Maharashtra and Karnataka) will necessitate greater investments in grid development and power system flexibility.

In the **ASEAN**, several policy improvements, including continued auctions (in the Philippines and Thailand) and corporate PPAs (in Viet Nam), lead to a more optimistic forecast for the region, but some challenges continue to prevent renewable energy from expanding almost 70% more than in our main case:

- In countries with fossil fuel overcapacity and ambitious long-term decarbonisation goals, it is a costly endeavour for utilities to install new renewable energy technologies in the place of young fossil fuel-fired power fleets established on long-term contracts with take-or-pay clauses for power offtake and fuel supply.
- Renewable energy technology costs in many of these markets still exceed international benchmarks, making them less competitive.
- Financing costs and project risks are high.

Meanwhile, for **sub-Saharan Africa**, additions in the accelerated case are nearly nearly 30% higher, mostly from solar PV and wind. Clear policies and regulations implemented in a timely manner, combined with additional investments in transmission and distribution infrastructure and innovative financing mechanisms facilitate higher capacity growth in this case. In addition, the liberalisation of energy markets in many countries could attract more new capacity. Kenya, Nigeria and South Africa have either passed legislation to liberalise their energy markets or it is pending, enabling bilateral agreements between corporations and independent power producers.

Renewable capacity growth could also be higher than in the main case in the nascent markets of **MENA** (+41%) and **Eurasia** (+39%), as both regions have significant untapped renewable energy potential and growing electricity demand. However, several challenges persist:

- Weak/slow grid infrastructure expansion limits electricity access and services.
- High financing costs reduce renewable energy project bankability.
- Visibility over auction volumes is inadequate and the period between announcement and contract-signing remains lengthy.

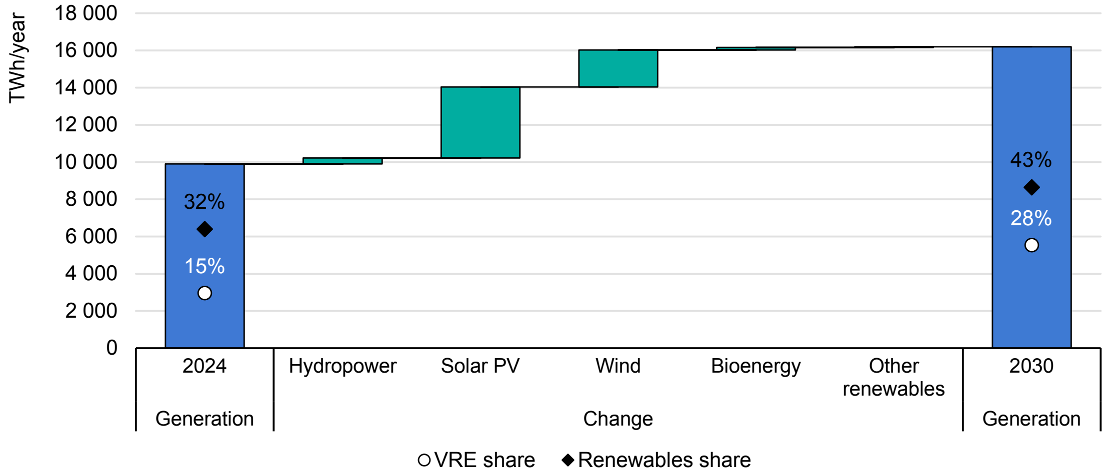
Renewables will become the largest global energy source, used for almost 45% of electricity generation by 2030

Electricity generation from renewables is expected to increase 60% – from 9 900 TWh in 2024 to 16 200 TWh in 2030. In fact, renewables are expected to surpass coal at the end of 2025 (or by mid-2026 at the latest, depending on hydropower availability) to become the largest source of electricity generation globally.

However, compared with last year’s estimates, we expect renewables to generate almost 850 TWh less electricity in 2030. There are two reasons for this lower expectation: first, as already discussed, we revised the capacity forecast 5% downwards, resulting in lower generation. Second, we refined our analysis of wind and solar PV curtailment by transitioning from the established assumptions used previously to a trend-based assessment supported by historical data (see the section below on the role of wind and solar PV in power systems).

Solar PV alone accounts for over 60% of the generation increase, followed by wind (32%). The share of renewables in global electricity generation is projected to rise from 32% in 2024 to 43% by 2030, while the share of variable renewable energy sources is set to almost double to 28%.

Global renewable power generation in 2024 and 2030, and change by technology



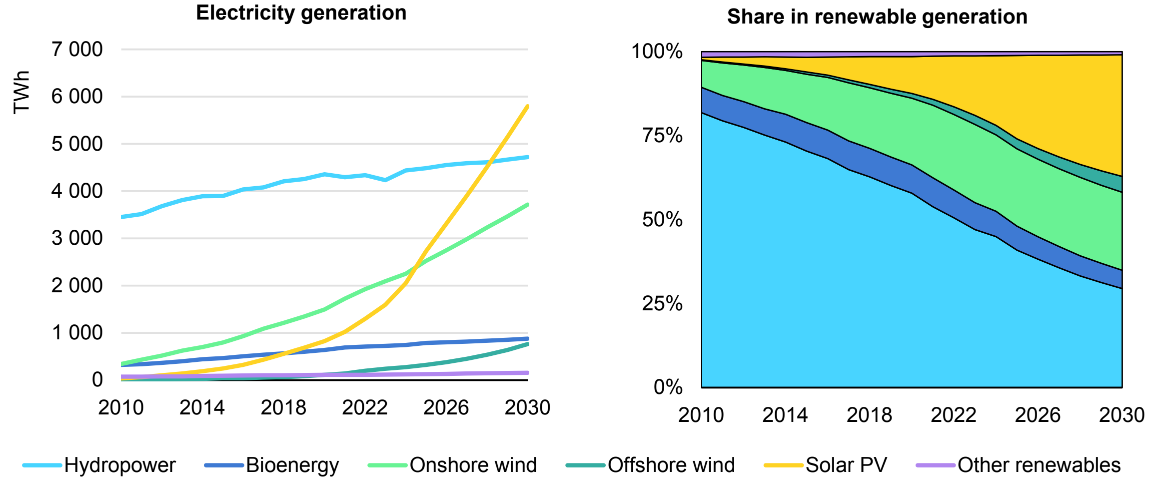
Notes: VRE = variable renewable energy. “VRE share” includes solar PV and wind.

Hydropower electricity generation is expected to increase 7% over 2025-2030 as new projects become operational, mostly in emerging and developing countries. However, its share in global electricity generation decreases slightly, by almost one percentage point to 14% in 2030. Hydropower will account for just 30% of global renewable electricity generation in 2030, a sharp decline from over 80% two decades ago.

In contrast, the role of solar PV and wind increases drastically: in 2030, variable renewables account for almost two-thirds of global renewable electricity generation, rising from less than 46% today. Solar PV is expected to generate more electricity than hydropower by the end of the forecast period and to become the largest renewable energy source. Onshore and offshore wind generation are also expected to grow rapidly, together reaching over 4 500 TWh by 2030.

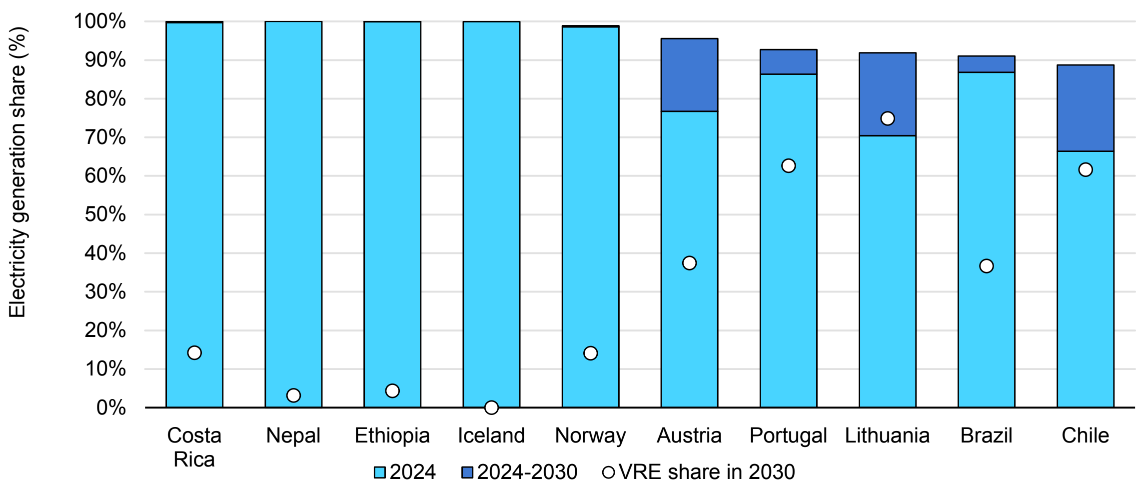
Clearly, the increased use of variable renewables raises the need for additional sources of power system flexibility. Nevertheless, bioenergy, geothermal and concentrated solar power expansions remain limited despite their critical role in integrating wind and solar PV generation into electricity systems around the world.

Global renewable generation and shares by source, 2010-2030



Among the ten countries with the highest shares of renewable electricity generation, five (Costa Rica, Nepal, Ethiopia, Iceland and Norway) stand out for already achieving nearly 100% renewable energy shares in their electricity mix, predominantly by using hydropower. In these countries, wind and solar PV make only minor contributions to the overall mix, highlighting the continued importance of hydropower. Iceland, however, has combined two dispatchable renewables – hydropower and geothermal resources – to reach 100%. Over the next five years, countries such as Portugal and Chile are projected to reach 90% renewables in their electricity mix, but variable renewables provide more than half.

Renewables shares in the 10 countries with the highest portions in their electricity mix



Notes: VRE = variable renewable energy. “VRE share” includes solar PV and wind.

Regional forecast summaries

China

The rush to beat policy changes led to record wind and solar deployment in 2025, but lower remuneration reduces the forecast for 2030

China's renewable energy capacity is expected to grow nearly 2 660 GW from 2025 to 2030, doubling the previous five-year expansion. Solar PV will dominate, accounting for 80% of this growth. By the end of 2024, China's combined wind and solar PV (AC) capacity already exceeded 1 400 GW, surpassing the 2030 target of 1 200 GW.

However, we have revised the forecast 5% downwards from last year to reflect policy changes announced since October 2024. The government has ended fixed-price remuneration for renewables and introduced market-based auctions as part of broader electricity sector reforms. While this policy change is a positive step concerning market reforms and renewables integration, it will lower returns for new projects and reduce growth.

In February 2025, the government set out guidelines requiring all wind and solar projects commissioned after 31 May 2025 to sell power through wholesale markets or market-based mechanisms. This led to a surge in project completion in early 2025, with nearly 200 GW of solar PV and 47 GW of wind installed in the first five months – significantly more than in the same period in 2024. The new auction system will replace fixed provincial benchmark prices with two-way contracts for difference (CfDs) implemented at the provincial level. Additionally, the previous requirement for storage approval for new projects was lifted.

The reforms will heavily influence renewable energy deployment over the next five years, but challenges remain. Auctions are expected to narrow profit margins due to intense competition among developers striving to offer lower prices to provincial governments. A major uncertainty is the readiness of wholesale electricity markets, as only five provinces had fully operational ones as of mid-2025, covering less than one-third of installed renewables. Delays or weak price signals could slow provincial auction and CfD rollouts. Plus, the transition to market pricing introduces revenue volatility, affecting solar PV developers especially and raising financing costs. Consequently, the utility-scale solar PV forecast has been cut back 12%.

Distributed solar PV forecast is slightly higher, however there are two different trends for commercial and residential applications. The outlook is weaker for residential installations. In 2024, following the phase-out of fixed tariffs and reduced provincial incentives, residential solar capacity additions dropped over 30% from the previous year. Meanwhile, commercial and industrial solar PV prospects are more positive, supported by declining module costs and rising retail electricity prices that improve the economics of self-consumption.

Following the policy change to CfDs, deploying higher-cost renewable energy technologies is expected to be more challenging without targeted support. Offshore wind costs remain high despite cost reductions for onshore wind, so investors are expected to favour onshore projects, leading to a 26% (26 GW) cut in offshore wind capacity projections over 2025-2030.

Bioenergy growth has decelerated sharply, with capacity additions in 2024 falling over 45% compared to 2023, consequent to slower urbanisation and reduced incentives. The bioenergy forecast has therefore been lowered by almost 55% for 2025-2030.

Meanwhile, hydropower forecasts show an important shift: pumped-storage hydropower (PSH) capacity additions exceeded conventional hydropower in 2023 and 2024. The need to balance variable renewables is driving this trend, with over 36 GW of PSH expected by 2030 – 40% above last year's forecast – while conventional hydropower additions were also slightly revised up to about 26 GW over the same period.

Grid integration challenges remain significant. Renewable energy curtailment volumes increased roughly 55% in 2024, reaching 4.1% for wind and 3.2% for solar PV, but is expected to stabilise at around 5-6% thanks to expanding HVDC transmission infrastructure and more utility-scale and behind-the-meter battery storage. Market reforms requiring wind and solar plants to participate in wholesale markets should improve dispatch efficiency and limit curtailment growth. Additionally, new rules introduced in 2025 allow direct grid-bypass connections between renewable power plants and large industrial consumers with storage, aiming to better align supply and demand. However, cost and reliability hurdles will likely limit rapid uptake.

In the accelerated case, China's renewable electricity capacity could be 13% higher. This case assumes several policy improvements, market developments and faster buildout of grid infrastructure for both transmission and distribution:

- Faster adoption of auction schemes in provinces that launch provincial wholesale electricity markets in a timely fashion from July 2025 to June 2026 (with the announcement of auction designs and solar PV and wind auction volumes – and the successful awarding of multiple rounds – raising investor confidence).
- A brisker pace of transition, speeding up power market reforms and green-energy certificate trading among provinces to facilitate system integration and promote greater interprovincial power exchange.

- Faster rollout of industrial solar PV systems, requiring quicker adaptation to new market integration rules and higher self-consumption requirements for distributed solar PV in an increasing number of provinces.
- Continued provincial economic support for residential solar PV projects.
- Swifter realisation of developments in the hydropower project pipeline, especially large conventional facilities.

Europe

Europe's forecast is slightly more optimistic because policy and market improvements drive faster expansion in various markets, but residential PV and offshore wind growth is slower

Europe is expected to add over 630 GW between 2025 and 2030, increasing capacity by 67% to 1 612 GW by 2030. Almost three-quarters of this rise is from eight countries: Germany, the United Kingdom, Spain, Türkiye, Italy, France, Poland and the Netherlands. Solar PV makes up the majority (over 70%) of expansion, split evenly between utility-scale and distributed projects, followed by onshore and offshore wind. Competitive auctions remain the main driver of utility-scale growth, while distributed PV relies on the economic attractiveness of self-consumption.

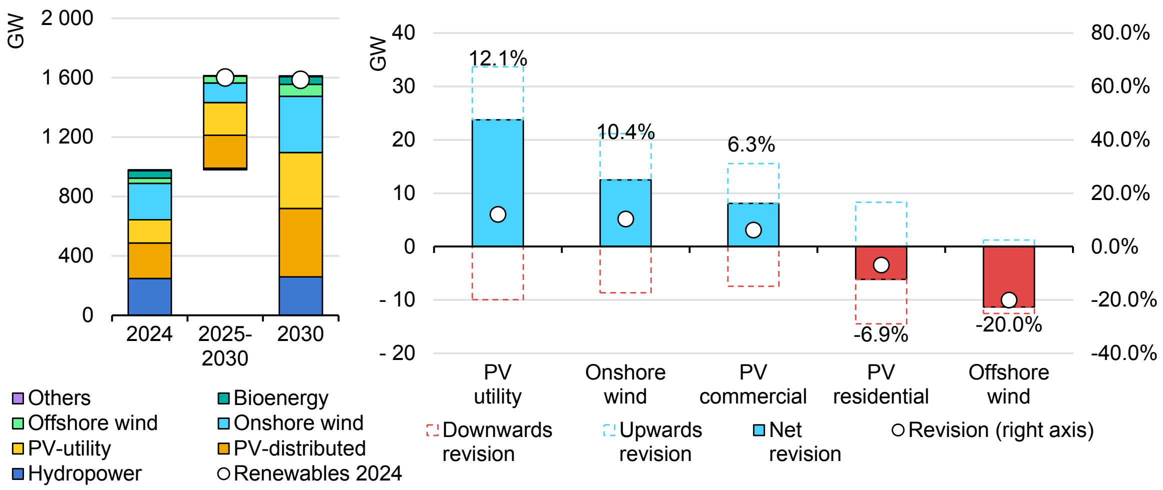
This year's forecast is slightly higher than last year's, owing mainly to higher growth prospects for utility-scale solar PV outside of auction schemes, and onshore wind developments in a few large markets. However, widespread permitting and grid integration challenges hamper faster expansion in other markets. Policy support and improved economics help boost the forecast for commercial PV, while residential self-consumption becomes less attractive during policy transitions and insufficient support hampers offshore wind uptake.

For solar PV, auctions remain the main driver of utility-scale growth, but unsubsidised project development plays an increasing role, accounting for 54% by 2030. As such, we have revised our forecast upwards by 12% to reflect the stronger-than-expected installations of corporate PPA and merchant plants during 2024 and in the first half of 2025 in Spain, Poland, Germany and Türkiye, where the economics are attractive. This upward revision offsets the lower expectations for unsubsidised projects in Portugal, Sweden and Denmark, where weaker project pipelines, the absence of auctions and lower market prices challenge growth.

We have also revised the onshore wind forecast up 10%, reflecting stronger prospects in Germany, Türkiye and Spain. In Germany, permitting reforms have enlarged project pipelines and led to oversubscribed auctions; in Türkiye, new auction capacity was scheduled for 2025; and in Spain, a larger pool of late-stage projects with grid connection approvals supports higher growth.

These gains partly offset downward revisions in Belgium, France, and Italy, where grid constraints or permitting challenges persist. Growth is also weaker in the United Kingdom, where recent reforms have yet to expand project pipelines, and in Poland, where planned reforms have been delayed. In Sweden, low demand, depressed wholesale prices and high imbalance costs undermine the economics of merchant projects, leading to a downward revision.

Renewable capacity (left) and revisions by technology and market (right) in Europe



Note: "Renewables 2024" refers to the amount of capacity forecast in IEA (2024), Renewables 2024.

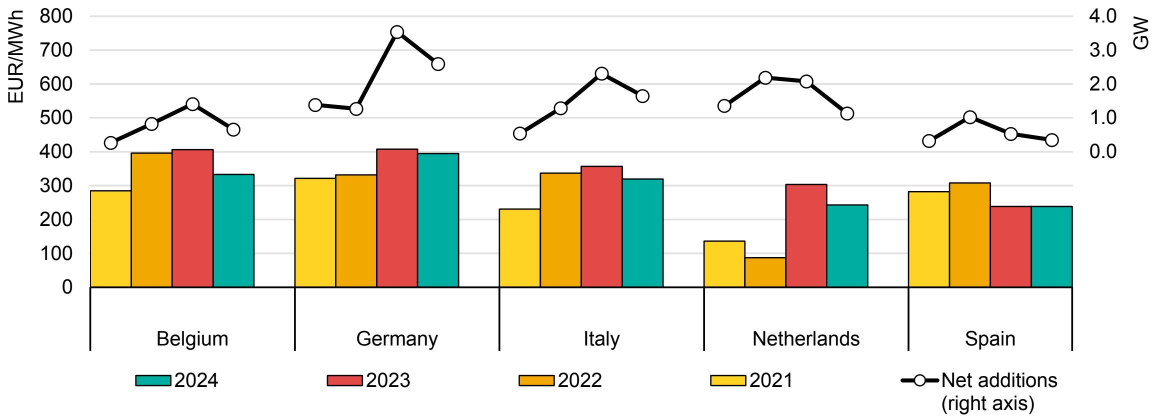
The commercial PV forecast has been revised up 6% to reflect higher-than-expected growth in 2024 stemming from policy support, economic attractiveness and energy security needs. In France, the carpark mandate accelerated deployment, while in Hungary the Casa Fotovoltaica scheme boosted installations. Activity was also stronger in Spain, Portugal, Romania, and Greece, as well as in Ukraine, where distributed PV provides backup power amid grid shortages caused by the war, particularly for retail and public service sectors. These upward revisions offset slower-than-expected growth in smaller markets such as Italy, the Netherlands, Bulgaria, Lithuania, Ireland and Germany.

Conversely, the residential PV forecast is 7% lower than last year because less favourable economics have been dampening consumer appetite. Many markets experienced a slowdown in growth in 2024 relative to 2023 as lower power prices and policy changes weakened the business case for self-consumption. In some markets the policy changes reflected a phasing out of measures introduced during the energy crisis, such as Italy's Superbonus, Spain's autoconsumo grants and

Belgium's temporary VAT exemption. Our forecast underestimated the impacts of these changes on 2024 deployment, so we realigned our expectations with 2024 growth.

In other markets, policy changes included switching from net metering to net billing to achieve more cost-effective deployment of distributed PV. While this switch lowers the remuneration value for the consumer, it incentivises consumption during peak hours and also reduces grid congestion as well as the amount of grid costs passed on to consumers. Because our forecast underestimated the impacts of these changes on 2024 deployment in Poland and parts of Belgium, we have revised our expectations downwards for these countries as well as for the Netherlands, which recently announced plans to also transition by 2027.

Residential sector retail electricity prices and annual capacity additions in selected European countries, 2021-2024



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Additional downward revisions reflect cuts to FITs in France, proposed tax-subsidy changes in Sweden, ongoing policy uncertainty in Switzerland, and weaker-than-expected H1-2025 deployment in Germany. These downward revisions outweigh upward adjustments to 17 countries for which we underestimated growth in 2024. In some cases, we simply undervalued the business case despite falling power prices (Hungary, Austria and Greece), while in others (e.g. Ireland and Portugal) elevated prices and continued policy support maintained stronger-than-expected growth.

Offshore wind capacity is forecast to grow 57 GW by 2030; however, this is 9 GW (15%) less than what we projected in Renewables 2024. This reduction reflects an increasingly challenging business case for planned projects and extended project timelines. Rising costs, supply chain constraints and uncertainty around future electricity prices have raised concerns about project viability, impacting over 5 GW of the forecast.

These challenging market conditions caused developers to opt out of Denmark's 3-GW auction in December 2024; cancellation of a 2.4-GW project in the United Kingdom; and a 1-GW reduction and delay in auction volumes in the Netherlands. Additionally, Belgium postponed a 700-MW tender due to cost and timeline concerns, and supply chain issues have also slowed progress in Germany and France. The forecasts for these markets have been adjusted downwards to reflect these conditions.

Reaching EU 2030 targets will require policy alignment, revenue certainty and the resolution of grid and permitting challenges

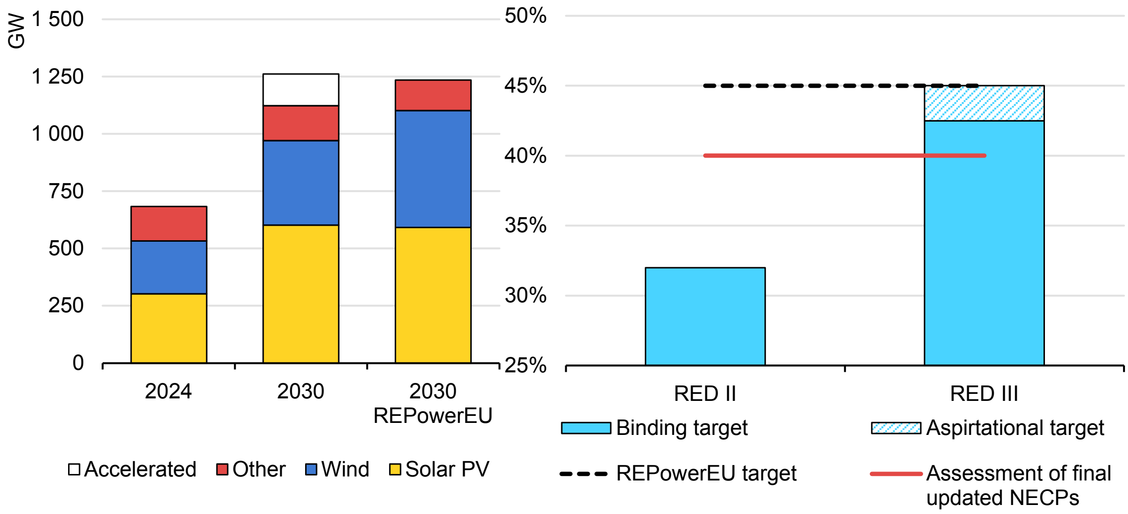
The European Union is expected to account for nearly 80% of Europe's renewable energy growth by 2030, adding over 500 GW of new capacity. This expansion would raise EU installed capacity from 683 GW in 2024 to 1 123 GW by 2030.[1] Nevertheless, this substantial increase fails to meet REPowerEU renewable capacity targets for 2030.

Introduced in 2022 following Russia's invasion of Ukraine, the plan aims to reduce reliance on imported Russian gas and enhance energy security by accelerating renewable energy deployment. It set an ambitious target of 1 236 GW[2] of installed renewable capacity by 2030 – including 592 GW[3] of solar PV and 510 GW[4] of wind. However, the main case expects EU installed capacity to fall 9% short of this target, largely due to two challenges.

The first is that the sum of individual EU member states' National Energy and Climate Plans (NECPs) is misaligned with the collective EU-wide target. The NECPs are ten-year plans that member states must submit to outline their contributions to achieve the EU-wide target for renewable energy in final energy consumption (which, together with energy efficiency targets, corresponds to a net GHG emissions reduction of 55% from the 1990 level by 2030). In 2023, the European Commission raised the binding 2030 target from the 32% set in 2018 under the Renewable Energy Directive (RED) II, to 42.5% for the RED III. It also set an aspirational goal of 45%, which corresponds to the REPowerEU Plan's 1 236-GW target, but it is not binding.

[1] For this total, solar PV is calculated in AC instead of DC, and pumped storage is excluded for comparability with the 1 236-GW REPowerEU target. Total capacity in the main case with solar PV calculated in DC is 756 GW in 2024 and 1 123 GW in 2030; for the accelerated case it is 1 260 GW.
[2] As per the REPowerEU Plan SWD (2022) 230 final, assumed to exclude pumped storage (as illustrated in the Implementing REPowerEU Plan SWD) and to include solar PV in AC (as referred to in the EU Solar Energy Strategy).
[3] The solar PV target is 592 GW in the Commission Staff Working Document COM (2022) 2030 final. We assume this value is in AC since it is similar to the "almost 600 MW by 2030" solar PV target identified in the EU Solar Energy Strategy SWD (2022) 148 final.
[4] The 2030 ambition for wind refers to the Implementing REPowerEU Plan SWD.

EU installed renewable capacity in 2024 and 2030 vs REPowerEU 2030 targets (left) and shares of renewables in final energy consumption in 2030 (right)



Note: RED = Renewable Energy Directive. NECP = National Energy and Climate Plan.
Sources: REPowerEU ambitions for total renewable capacity are from REPowerEU Plan SWD (2022) 230 final; wind and solar PV are from Implementing the REpowerEU Action Plan. The solar PV ambition is in AC, as it is similar to the "almost 600 MW by 2030" target identified in the EU Solar Energy Strategy SWD (2022) 148 final. The 2030 EU offshore wind ambition is from Delivering on the EU Offshore Renewable Energy Ambitions, and the onshore wind aim is the difference between the 520-GW REPowerEU ambition and the 111-GW offshore wind target in Delivering on the EU Offshore Renewable Energy Ambitions. All solar PV values are in AC, including for the main and accelerated cases, and all solar PV totals are calculated in AC. The member-state ambition is estimated from NECPs.

In June 2024, member states submitted their final updated NECPs outlining their voluntary contributions towards the EU goal. However, the European Commission's assessment of these final NECPs indicates that, in aggregate, they reach only a 40% renewable share – falling 2.5 percentage points short of the binding EU target and 5 percentage points below the REPowerEU ambition. This gap suggests that REPowerEU capacity aims are not aligned with final individual NECPs.

The second reason for the forecast shortfall in meeting EU-wide ambitions is that persistent challenges to faster solar and wind uptake require stronger policy attention. In the accelerated case, EU capacity reaches 1 255 GW[5] by 2030, on track to reach the REPower EU target. Achieving more rapid expansion will require four key policy actions:

- **Introduce auctions to provide revenue certainty.** Because auctions for long-term contracts provide revenue certainty, financing costs can drop. Clearer visibility over future auction schedules would help developers plan where to concentrate resources and co-ordinate future investment efforts.

[5] For this total, solar PV is calculated in AC instead of DC, and pumped storage is excluded for comparability with the 1 236-GW REPowerEU target. Total capacity in the main case with solar PV calculated in DC is 756 GW in 2024 and 1 123 GW in 2030; for the accelerated case it is 1 260 GW.

- **Increase system flexibility.** Expanding storage capacity, implementing demand response and strengthening interconnections would help curb curtailment, reduce the frequency of negative pricing hours and limit price cannibalisation, which in turn would improve growth prospects, especially for projects that rely on merchant revenues. Additionally, increasing support for storage solutions and smart meter deployment would make self-consumption more economically attractive for consumers.
- **Reduce permitting wait times.** Permitting remains a major bottleneck in the renewable energy deployment process, particularly for wind projects, which often have lead times of 7-10 years. Lengthy and complex approval processes can delay project development and limit participation in auctions. In Italy and Poland, for example, permitting delays have contributed to several undersubscribed auctions. Accelerating growth will require comprehensive reforms to simplify and speed up permitting procedures, including streamlining environmental assessments and digitalising application processes, as recommended in the EU Affordable Energy Action Plan. For instance, Germany's recent permitting reforms increased the number of approved projects by 86% between 2023 and 2024, enabling four consecutive onshore wind auctions to be fully subscribed for the first time since such auctions were introduced.
- **Modernise grids to reduce connection queues.** Insufficient distribution, transmission and interconnection capacity has limited the pace at which new renewable power plants can be connected to the grid. These constraints can lead to project delays, higher costs and reduced auction participation – as seen in the Netherlands. The proposed European Grid Package, expected in 2026, aims to address these challenges by offering clearer guidance on legislation, planning and funding to support grid expansion and modernisation.

Asia Pacific

India emerges as the second largest renewables market in the world, while ASEAN deployment gains momentum

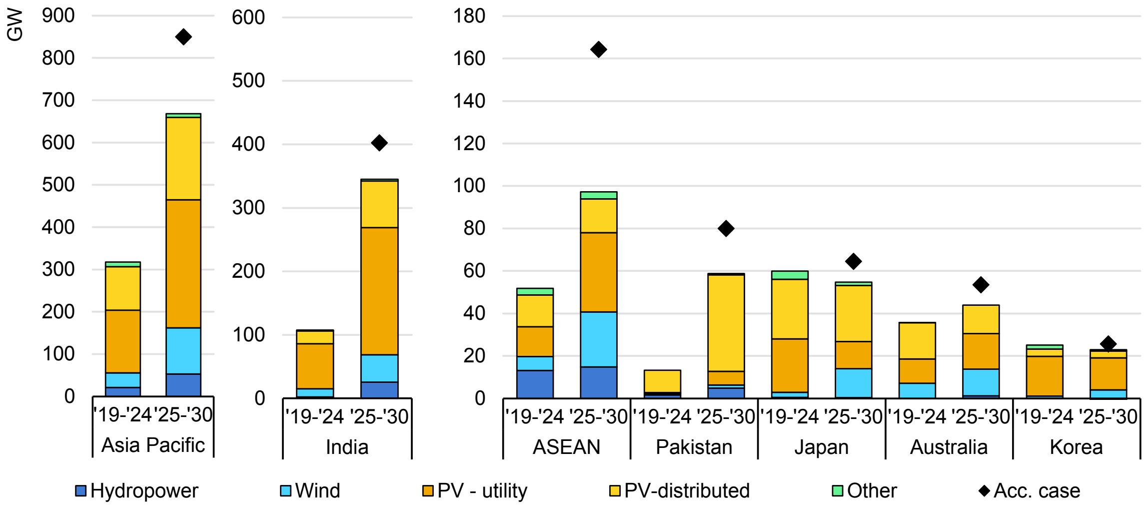
Renewable energy capacity in Asia Pacific (excluding China) is set to almost double over 2025-2030, expanding by 670 GW – the second-highest regional increase after China. India accounts for over half of the expected growth, followed by ASEAN countries (15%). In terms of national markets, Pakistan emerges as the second largest (9%), reflecting updated assessments of previously unregistered distributed solar PV installations. The third and fourth largest contributors are Japan (8%) and Australia (7%).

Solar PV is expected to account for nearly three-quarters of total renewable capacity additions in the region, with utility-scale projects making up most of the growth. However, deployment trends differ across countries: utility-scale systems dominate in India, ASEAN, Australia and Korea, while distributed PV plays a more prominent role in Pakistan (including off-grid) and Japan.

Asia Pacific is also projected to be the second largest hydropower market during the forecast period, largely because of accelerated commissioning of both conventional and pumped-storage hydropower (PSH) projects in India. Offshore wind capacity is set to close to quadruple, reaching 19 GW by 2030, driven by the rollout of the first large-scale projects in Korea and Japan as well as accelerated development in Chinese Taipei.

The overall regional forecast has been revised upwards by almost 10% from last year, reflecting improved policy and market conditions in India, Viet Nam and Pakistan. These positive developments offset downward revisions in Japan, Korea and Indonesia. In the accelerated case, regional capacity growth is over 25% higher than in the main case, with the strongest relative upside potential in ASEAN markets.

Net capacity additions in Asia Pacific, main and accelerated cases, 2019-2030



Notes: ASEAN = Association of Southeast Asian Nations. Asia Pacific excludes China.

India is forecast to add close to 345 GW of renewable electricity capacity between 2025 and 2030, more than tripling its 2022 level. It is expected to be the world's second-largest national market for renewables growth through 2030. Auction-driven utility-scale solar PV uptake accounts for nearly 60% of this increase. The forecast has been revised close to 10% upwards from last year owing to record auction volumes in 2024, the launch of a new rooftop PV support scheme, and faster permitting for PSH projects.

Capacity growth is spurred largely by auctions conducted by the central government, state authorities and utility companies (DISCOMs). In 2024, 63 GW of capacity were awarded – almost three times the volume of 2023 – with hybrid tenders (combinations of PV, wind and storage) accounting for more than half. Although auction volumes fell in early 2025, a robust project pipeline supports continued deployment acceleration throughout the forecast period.

Hydropower additions are also set to rise sharply – more than tenfold compared with the previous six years – with the completion of large-scale projects and a tripling of PSH capacity by 2030 as the Central Electricity Authority streamlines permitting. India also opened its first offshore wind tenders in 2024, targeting 4.5 GW. However, limited developer interest caused tenders to be cancelled in August 2025. Because project timelines are long, no offshore capacity is expected online before 2030 in our main case.

Under the accelerated case, renewables growth in India could be over 15% higher – surpassing 2030 ambition. This growth could be achieved by addressing challenges related to the financial difficulties of many DISCOMs; improving the enforcement of renewable portfolio standards; and reducing delays in signing PPAs with auctions winners.

Meanwhile, **Pakistan** is forecast to add nearly 60 GW of renewable power capacity, led by solar PV and hydropower. This year's significant upward revision is based on new estimates of unregistered off-grid solar PV deployment. Imports of solar modules from China indicate roughly 6 GW of new off-grid capacity installed in 2024 alone. In fact, off-grid PV, often paired with batteries, is expected to account for 55% of all additions as households and businesses seek to mitigate load shedding. Large hydropower projects will also contribute around 5 GW.

Japan is projected to add 55 GW of renewable capacity over 2025-2030, reaching 240 GW (DC), in line with its 2030 ambition. Solar PV will make up 70% of the additions, with wind playing a growing role. The forecast has been revised down slightly, however, to reflect slower-than-expected solar deployment in 2024. Competitive feed-in-premium auctions and a growing corporate PPA market support new capacity. Offshore wind is expected to grow from 0.3 GW to 2.5 GW, backed by government tenders, R&D support and simplified permitting.

In **Korea**, renewable power capacity is set to expand 22 GW, reaching 67 GW by 2030 – falling short of the 76-GW national ambition. Corporate procurement continues to drive large-scale solar and wind development, supported by Renewable Energy Certificates (RECs). For distributed PV, the renewable portfolio standard and building mandates are key enablers. Korea's first utility-scale offshore wind farms are expected online before 2030, spurred by auctions, REC incentives and local government backing.

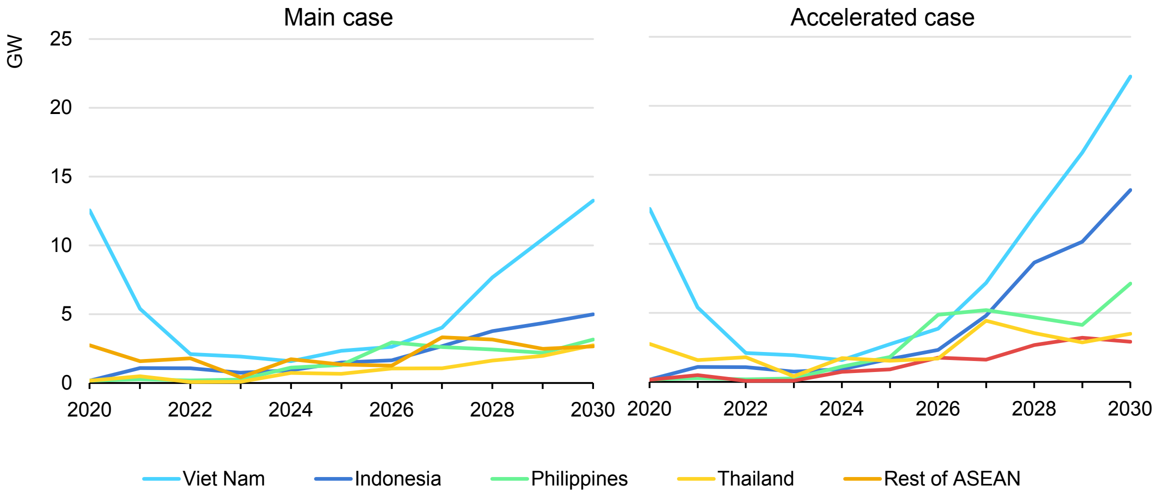
For **Australia**, the outlook remains unchanged from last year, with the country expected to add almost 45 GW of renewable capacity, primarily solar PV.

Expanded state-level auctions, the Capacity Investment Scheme and strong corporate demand support growth. These incentives, coupled with continued distributed solar PV expansion, will help Australia exceed its 2030 capacity ambitions.

The renewable electricity capacity forecast for the **ASEAN** region has been revised almost 15% upwards from last year, primarily owing to improved outlooks for Viet Nam, Thailand and the Philippines. Between 2025 and 2030, ASEAN countries are expected to add over 95 GW of renewable energy capacity – nearly double the deployment of the previous six-year period. More than half of these additions will come from solar PV.

Viet Nam is the region's leader, accounting for over 40% of total growth, followed by Indonesia (20%). Both countries are anticipated to accelerate capacity expansion significantly towards 2030, particularly if remaining barriers are addressed under the accelerated case. Overall, the combination of more ambitious policy targets, strengthened implementation frameworks and increased adoption of grid flexibility solutions could enable renewable deployment in ASEAN to reach 70% above the main case – the highest upside potential of all major regions.

Net capacity additions in ASEAN, main and accelerated cases, 2020-2030



Note: ASEAN = Association of Southeast Asian Nations.

Viet Nam is expected to add 40 GW of renewable energy capacity over 2025-2030, led by onshore wind and utility-scale PV. In April 2025, it updated its national Power Development Plan (PDP8) to significantly raise its 2030 ambitions, particularly for solar PV, prompting a 20% upwards revision to our forecast. The government also enabled direct PPAs between large consumers and generators, providing an additional boost to utility-scale deployment.

The current slowdown in new utility-scale PV and wind development is expected to gradually ease towards 2030 as grid congestion challenges are addressed and government tendering activity accelerates. In the accelerated case, if investments in power grids and system flexibility gain momentum, and large-scale tenders are launched quickly, capacity growth could be 60% higher by 2030, aligning with PDP8 targets.

Indonesia is projected to add almost 20 GW of renewable power capacity in 2025-2030 – quadrupling the modest growth of 2019-2024. Utility-scale solar PV leads the expansion, followed by hydropower and distributed PV, with notable additions of onshore wind, geothermal and bioenergy capacity. Its latest (more ambitious) Electricity Supply Business Plan (RUPTL 2025-2034) aims to add almost 18 GW of renewables – including 1 GW of PSH – and the country is expected to exceed this goal.

However, we have revised our forecast down 10% from last year. Considering Indonesia's long-term ambition for net zero emissions by 2060 and its massive untapped potential for all renewable energy, last year's forecast expected higher targets. The accelerated case shows that more ambitious plans, concrete support policies and greater flexibility in fossil fuel-fired generation contracts could more than double renewables growth.

Meanwhile, **the Philippines** is expected to add nearly 15 GW of capacity, with solar PV and onshore wind making up 90% of additions. This represents a 5-GW (around 50%) increase over the previous forecast, owing to completed and ongoing competitive auctions. If challenges such as grid connection delays, high financing costs, land access restrictions and permitting bottlenecks are addressed, growth could be 90% higher, putting the country on track to exceed its targeted 35% renewable electricity share by 2030.

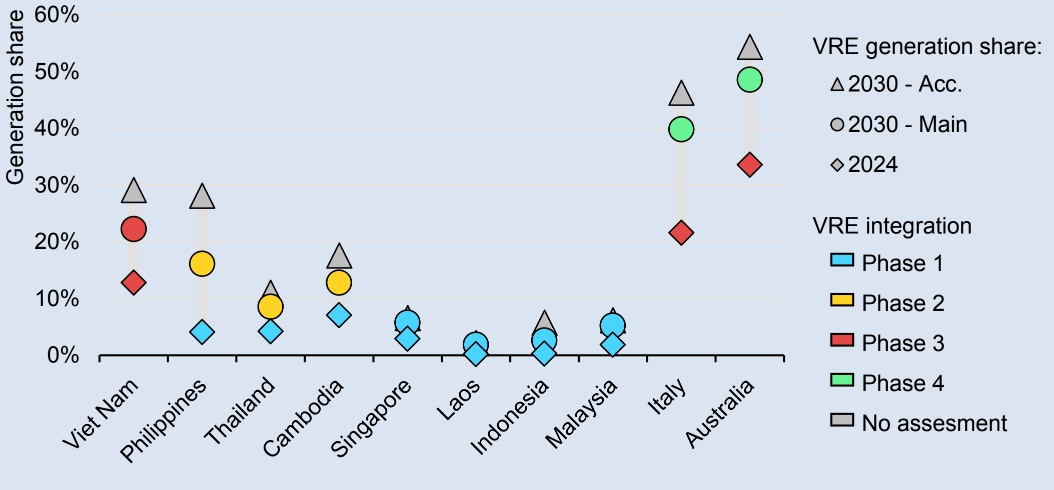
Thailand is expected to add 9 GW of renewable energy capacity between 2025 and 2030, primarily through utility-scale and distributed PV applications and onshore wind. The main catalyst for renewable energy growth promises to be the 2022-2030 renewable procurement programme, with feed-in-tariff contracts awarded to more than 2 GW of wind and PV projects in 2024. In the accelerated case, renewable energy deployment could be around 45% higher To achieve this growth, the government would need to address grid connection and permitting challenges, conclude pending PPAs, and enable a faster scale-up of the PPA market.

ASEAN countries can use existing infrastructure and improved contractual flexibility to integrate rising VRE shares by 2030

The IEA's VRE integration framework classifies power systems into six phases, with each phase reflecting the operational challenges and measures required to integrate higher penetrations of solar PV and wind power generation. Phases 1 to 3 are considered low, with VRE having a limited to moderate impact on system operations, while Phases 4 to 6 are advanced, with growing implications for long-term system reliability and stability (see section on VRE integration phases).

In 2024, nine out of ten ASEAN member states remained at Phase 1. By 2030, six countries – including Malaysia, Laos, Myanmar, Singapore and Brunei – are still expected to be at this phase with a less than 5% share of domestic VRE. In Phase 1, the VRE impact is insignificant at the system level and remains localised to grid connection points.

VRE generation shares and integration phases of selected countries, 2024-2030



Notes: VRE = variable renewable energy. Acc. = accelerated case. Main = main case. Phase assessments are based on multiple parameters beyond VRE share in annual generation, including hourly generation and demand profiles, power grid configuration and installed dispatchable capacity.

By 2030, Cambodia, the Philippines and Thailand are expected to have transitioned to Phase 2, for which integration challenges are moderate and can typically be rectified by upgrading operational practices and making better use of existing assets (e.g. by improving VRE generation forecasting and enabling more flexible dispatchable power plant operations).

Viet Nam reached Phase 3 already in 2024, with VRE determining operational patterns and increased net-load (net electricity demand and VRE generation) variability and uncertainty prompting more significant changes in system operations. Rapid VRE deployment, concentrated in areas with limited grid capacity, has led to transmission congestion, curtailment and operational challenges, particularly along the north-south transmission corridor. Viet Nam is forecast to still be at Phase 3 in 2030, facing the most pronounced integration challenges in ASEAN, including the high ramping requirements and low midday net loads associated with a steep “duck curve” trajectory.

However, these conditions will likely be comparable to those already experienced in the high-VRE systems of Italy, Spain and Australia, where proven solutions have been successfully applied. Increasing system flexibility beyond the use of existing assets will become necessary, including by reinforcing transmission and distribution grids, enhancing thermal plant flexibility and deploying large-scale storage – both batteries and PSH systems.

Across the ASEAN region, renewable energy integration challenges (particularly those affecting ramping and minimum net loads) are projected to rise by 2030. Nevertheless, they can remain manageable if existing assets are operated more flexibly. Thermal and hydropower plants will play a central role given their technical flexibility, but in many countries – including Indonesia, Thailand and Viet Nam – their flexibility is constrained by long-term power purchase agreements (PPAs) and fuel supply contracts.

PPAs are often structured as firm commitments that include minimum offtake requirements and capacity payments, guaranteeing returns for conventional generators. As a result, thermal power plants are not obligated to operate flexibly, which affects overall system efficiency. Utilities are required to purchase fixed volumes of electricity regardless of demand to meet their contractual obligations. Similarly, fuel supply contracts with take-or-pay clauses (common in gas and other fossil fuel agreements) effectively treat fuel as a sunk cost and distort the marginal cost of thermal generation.

These contractual rigidities can result in uneconomic dispatching, particularly during periods of low net demand, raising system costs and limiting the ability of utilities to contract new renewables. This challenge is especially pronounced in countries with significant thermal overcapacity, such as Indonesia and Thailand, where reserve margins have reached around 50%.

Addressing this issue requires a multidimensional approach that ensures fairness, safeguards long-term security of supply and avoids stranded assets while facilitating faster VRE deployment. Although renegotiating existing contracts is often difficult, new contracts can be structured to provide greater flexibility. Possible measures include:

- Reducing minimum-take obligations in PPAs to allow greater optimisation of dispatch according to system needs.

- Introducing flexible operational requirements for thermal plants, such as lower minimum stable levels, higher ramp rates and the ability to cycle with frequent startups and shutdowns.
- Diversifying fuel supply portfolios by combining long- and short-term contracts to improve fuel procurement flexibility.
- Unbundling capacity, energy and ancillary services contracts, enabling the system to valuate and procure each service separately. This approach can incentivise retrofits of older plants to provide necessary system services.

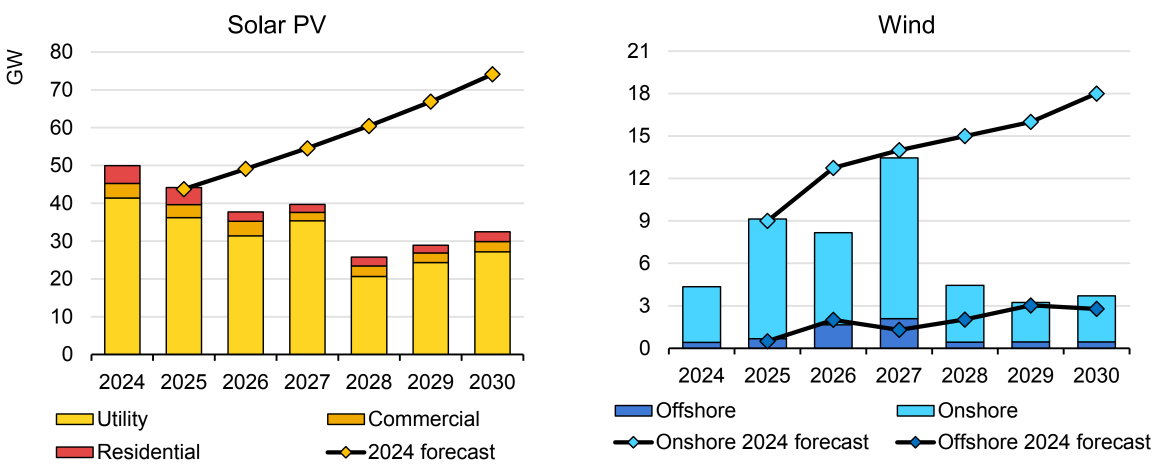
The IEA's VRE integration assessment shows that most ASEAN countries remain in the earliest phases of integration, highlighting significant potential to accelerate solar PV and wind deployment by 2030 without jeopardising system reliability. In more advanced markets, however, unlocking the flexibility of existing generation assets through contractual reform will be key to efficiently integrate growing VRE shares.

United States

Recent policy changes lead to a downward forecast revision

The United States is expected to add almost 250 GW of renewable power capacity between 2025 and 2030, primarily consisting of solar PV and wind energy projects. However, recent policy changes have prompted us to revise this year's forecast downwards almost 50% from last year's.

Solar PV and wind capacity additions in the United States, 2024-2030



A significant factor in this revision is the comprehensive One Big Beautiful Bill Act (OBBBA), passed in July 2025. This legislation introduces important amendments to the renewable energy support mechanisms of the 2022 Inflation Reduction Act (IRA).

Since their introduction in 1992, tax credits have been the main driver of renewables growth in the United States. The OBBBA accelerates the phase-out of investment tax credits (ITCs) and production tax credits (PTCs) for all zero-emissions power generation technologies, with shorter timelines for utility-scale solar, wind, and energy storage. Under OBBBA, these projects must be commissioned by 31 December 2027 to qualify for tax credits unless construction begins within 12 months of enactment of the bill, which grants a four-year continuation window under the "safe harbour" provision.

In August 2025, the Internal Revenue Service (IRS) released new construction-start rules for wind and solar PV projects. Previously, most developers had the option of spending 5% of total project investment costs before the beginning of the construction deadline, under what were also called safe harbour rules. The new IRS legislation removes this option for all wind and solar PV projects larger than 1.5 MW and instead requires performance of a "physical work test".

With the pushing forward of deadlines, renewable capacity additions are now projected to peak in 2027, then decline in 2028 and remain stable through 2030. After this period, renewable power growth will rely largely on state-driven renewable portfolio or clean energy standards and corporate PPAs, rather than federal incentives.

For residential solar PV, the outlook is weaker because the OBBBA phases out residential solar tax credits earlier (by the end of 2025), reducing financial incentives for homeowners. This, combined with reductions in state-level net metering policies (which were previously supportive), is expected to slow growth in residential solar installations.

In January 2025, the federal government issued an executive order that paused all new or renewed federal leases, permits and approvals for offshore wind projects in federal waters, and similarly suspended permitting for all wind and solar PV projects on federal land. Thus, as a result of recent policy changes and developments, we have revised the offshore wind forecast down more than 50% from last year's projections.

In addition to recent policy changes, previous challenges also persist. Grid connection queue backlogs and interconnection delays continue to hinder project development despite ongoing efforts to streamline processes. Moreover, some counties have imposed stricter land-use restrictions, impacting site availability for onshore wind and solar PV development. Solar PV projects face further cost pressures due to anti-dumping and countervailing duties (AD/CVD) on modules imported from countries such as Cambodia, Malaysia and Viet Nam, along with increased tariffs on Chinese solar cells.

These tariffs could drive up costs just when federal subsidy support is ending. Plus, tariffs on non-energy-specific technologies and components may create additional financial pressure as the administration applies them to enabling infrastructure and construction materials, such as steel for transmission and distribution wires.

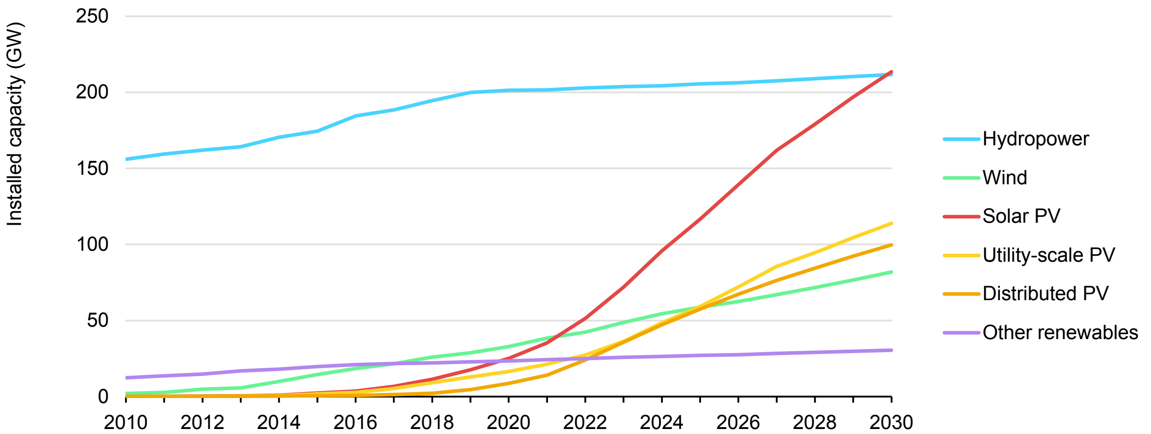
Despite these headwinds, the accelerated-growth scenario anticipates nearly 24% higher capacity additions than in the main forecast. This optimistic outlook assumes the effective mitigation of current challenges through expanded corporate renewable energy procurement and stronger state-level renewable portfolio standards.

Latin America and the Caribbean

Solar PV is set to tie hydropower for largest installed capacity in 2030

The Latin America and Caribbean region is expected to add almost 160 GW of renewable energy capacity by 2030, with solar PV making up most of this growth. In fact, solar PV is projected to match hydropower in total installed capacity by 2030.

Total installed renewable capacity by technology in Latin America and the Caribbean, 2010-2030

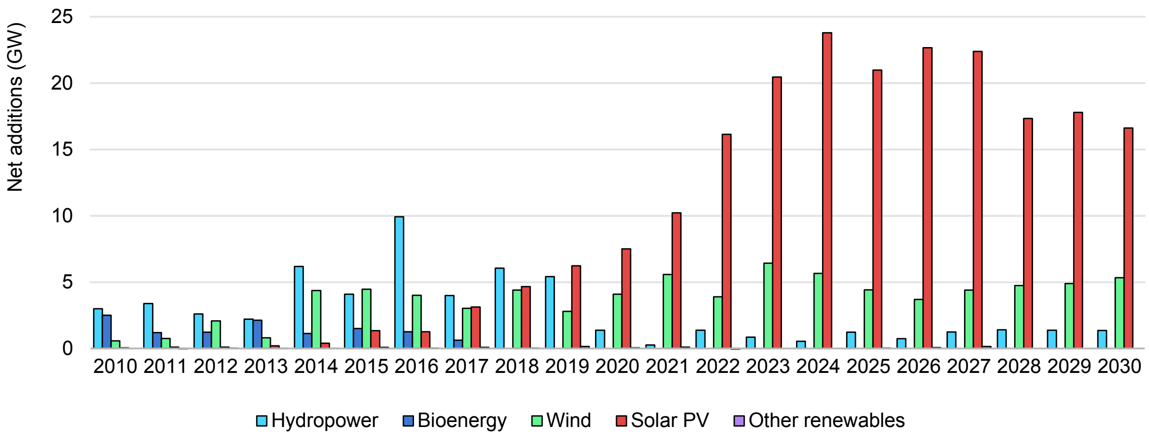


While both utility-scale and distributed solar PV are expanding rapidly and their capacities were roughly equal between 2023 and 2025, utility-scale installations are forecast to outpace distributed systems in upcoming years. Solar PV capacity overtook wind in 2022, and by 2025 both utility-scale and distributed solar PV each individually match wind capacity.

Hydropower has long been the largest renewable electricity source in Latin America, and it continues to be critical in many countries across the region. Although the regional outlook for hydropower remains similar to last year, some markets still hold significant untapped potential. Colombia, for instance, is set to lead in new hydropower capacity, largely owing to completion of the 2.4-GW Ituango project. However, further large-scale hydropower development remains challenging due to environmental, social and financial constraints in multiple countries.

In recent years, solar PV has gained increasing importance in Latin America's energy transition. Throughout the 2020s, it has taken on a leading role, surpassing wind in capacity additions. It will be the primary driver of renewable energy growth, with utility-scale projects contributing 41% and distributed systems accounting for 33% of new capacity in 2025-2030.

Net renewable capacity additions by technology in Latin America and the Caribbean, 2010-2030



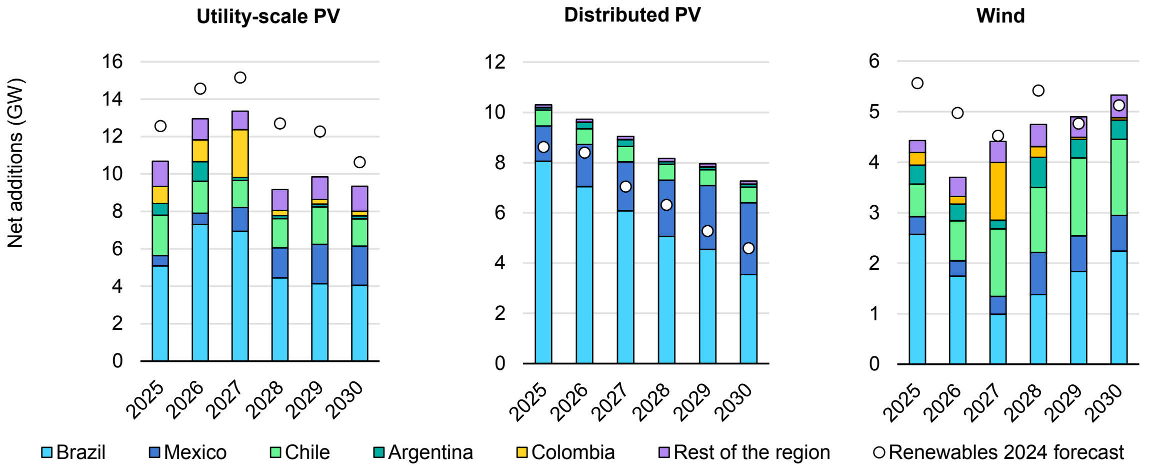
Three countries are forecast to provide more than 80% of renewable capacity expansion in Latin America over the forecast period. Brazil leads regional expansion, installing about half of the new capacity, and Mexico and Chile each contribute roughly 15% to the region’s overall growth.

Overall, the regional forecast has been revised down slightly (by 3%). While this revision is modest, it masks more significant shifts at the country and technology levels. Projections have been reduced 16% for utility-scale solar PV and 9% for wind, whereas distributed solar PV has been revised up 30%, offsetting the decline.

Forecasts for utility-scale solar PV and wind reveal diverging trends across key Latin American markets. For Brazil, projections have been revised downwards because curtailment (particularly in the Northeast) and transmission bottlenecks are reducing project profitability, lengthening connection queues and extending project lead times. Curtailment also remains a key challenge in Chile, but the government is addressing it through grid expansion auctions and strong battery deployment, while a steady flow of permit requests indicates sustained interest in renewable power projects. Conversely, Mexico's energy forecast has expanded since the country launched a USD 22-billion energy plan in early 2025, targeting 29 GW of new capacity – 6.4 GW from variable renewables – along with grid upgrades, storage expansion and revived projects.

For distributed PV, 30% more growth in the region is estimated in this year's forecast than in last year's. In Brazil, despite a 2023 policy change reducing remuneration under the net-metering scheme, distributed solar PV additions remain robust. Meanwhile, Mexico experienced record growth in distributed solar PV in 2024, adding 1 GW and reaching half a million users. This surge is largely the result of its attractive net metering programme, which is expected to enable an additional 13 GW of capacity by 2030, particularly benefiting commercial customers after the system-size threshold was increased from 0.5 MW to 0.7 MW.

Net renewable capacity additions by country and technology in Latin America, 2025-2030



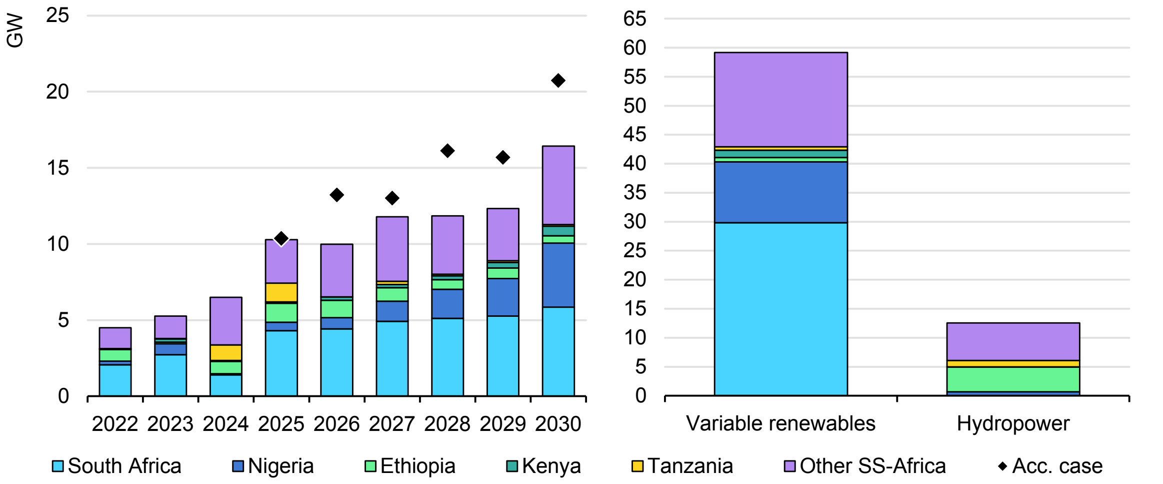
Slow grid expansion continues to pose a significant challenge across Latin America. In Brazil, the increasing deployment of variable renewable energy has caused lengthy connection queues, resulting in longer project development timelines. To address these issues, new transmission line tenders have been held. Similarly, delays in expanding transmission infrastructure in Colombia have lengthened project timelines as multiple renewable power projects await grid connection. Meanwhile, in Chile the grid has struggled to keep up with rapid variable renewable energy growth, leading to higher curtailment rates.

Sub-Saharan Africa

South Africa continues to lead growth in the region, with solar PV dominating

Over 70 GW of new renewable electricity capacity is forecast for sub-Saharan Africa from 2025 to 2030, more than doubling the region's current installed capacity. Expansion happens mainly in South Africa, which is responsible for installing over 40% of the region's new capacity. Outside of South Africa, hydropower makes up the majority of total additions in Ethiopia (4.2 GW) and Tanzania (1.1 GW), while solar PV leads renewable energy growth in Nigeria (10.5 GW) and Kenya (1 GW).

Sub-Saharan Africa capacity additions by country, 2022-2030 (left(), and total additions by technology, 2025-2030 (right)



Notes: SS = sub-Saharan. Capacity additions refer to net additions.

Solar PV and wind additions make up over 80% of new capacity in the region, mainly thanks to South Africa's auction programme for utility-scale renewables and coupled power sourced through corporate PPAs, and from distributed solar PV installations. However, other markets are also beginning to play a larger role in solar PV and wind expansion. In Nigeria, fossil fuel subsidy phase-outs and continuous blackouts are catalysing 5.5 GW of new distributed solar PV developments. In Kenya, projects carried over from the country's old feed-in-tariff programme, coupled with distributed installations, account for over 1 GW of new capacity.

Most wind power additions come from South Africa under bilateral agreements or the country's auction scheme, though awarded wind volumes have declined due to a lack of grid availability. Outside of South Africa, policy uncertainty and the lack of a long-term plan for wind deployment mean that many developments based on several key projects are backed by national utilities, aid agencies or development banks. For example, the recently completed 100-MW Assela wind farm in Ethiopia developed by Ethiopian Electric Power received financial backing from Denmark.

While solar PV and wind make up most additions in the forecast period, hydropower remains key for development in many markets. In fact, hydropower represented more than half of all new additions in the region in 2024. Large projects – such as full commissioning of Angola's Caculo-Cabaca Hydropower Station, and the continued commissioning of Tanzania's Julius Nyerere Hydropower Station and Ethiopia's Grand Ethiopian Renaissance Dam – contribute substantially to annual additions. Large-scale hydropower also remains very important for Ethiopia (over 80% of forecast additions) and Tanzania (almost 65% of all additions).

While the majority of hydropower additions are large-scale projects, electrification remains an important driver for small hydropower development. Nevertheless, the role of hydropower declines throughout the forecast period, representing 17% of all additions when previously it made up more than 40% in 2013-2024.

Also driving new capacity developments are corporate PPAs and power exports. Corporate entities are sourcing their own renewable power, either through a government-sponsored programme or a market structure that allows bilateral agreements or self-supply. This trend is especially strong in wind power development in South Africa, where corporate purchasing will encourage most new wind power expansion because it is challenging to meet grid connectivity requirements to participate in the country's auction programme. Large-scale hydropower plants are also being built for export purposes in countries such as Ethiopia and Tanzania, where the Julius Nyerere Hydropower Project has begun exporting power to the regional power pool.

Finally, off-grid solar PV systems also help expand electrification (especially in areas not served by the grid), with over 1 GW of new capacity expected by 2030. According to national plans and nationally determined contributions, many countries have off-grid solar capacity ambitions. Federal rural electrification agencies are emphasising solar PV for electrification, and sub-Saharan Africa remains a major market for solar kits (e.g. for lighting, pumping water and refrigeration). In Nigeria – the country with the highest number of people lacking access to electricity – the Rural Electrification Agency has partnered with private developers and multilateral development banks to deploy mini-grids across the country.

Regional challenges include stop-and-go policies; high offtaker risks; and low grid availability and reliability. Policy implementation delays are stalling renewable energy development, while outstanding payments to independent power producers can weaken investor confidence. Low system availability and reliability can lead to long connection wait times, impacting project timelines.

Additions in our accelerated case are nearly 25% higher, mostly from solar PV and wind. Clear policies and regulations implemented in a timely manner, combined with additional investments in transmission and distribution infrastructure and innovative financing mechanisms facilitate higher capacity growth in the accelerated case. In addition, energy market liberalisation in many countries could attract more new capacity. Kenya, Nigeria and South Africa have either passed legislation to liberalise their energy markets or it is pending, enabling bilateral agreements between corporations and independent power producers.

Policy and procurement trends

Ambition and implementation

Almost all new NDC submissions acknowledge the importance of renewables, but they fall short of the COP28 ambition of tripling global renewable capacity by 2030

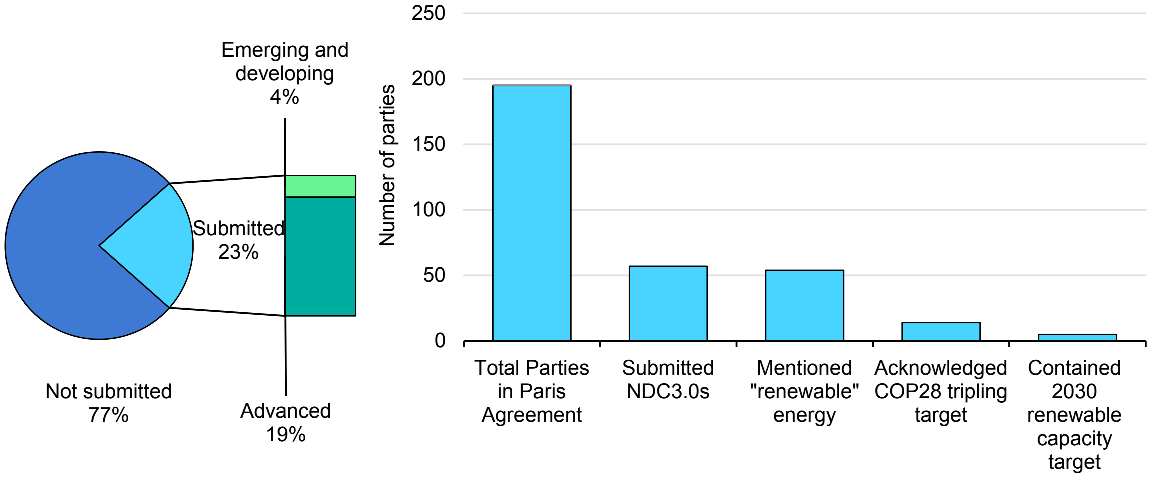
COP30 is an important milestone, as it will be an opportunity to assess the implementation approaches governments are using to achieve the shared pledge of tripling global renewable electricity capacity to around 11 500 GW by 2030. The target was agreed upon at COP28 in 2023 as one of the main outcomes of the Paris Agreement’s first Global Stocktake (GST1), which revealed that existing country plans (as outlined in their Nationally Determined Contributions [NDCs]) were off track to limit warming to 1.5°C.

In addition, countries were expected to submit new or updated NDCs (NDC 3.0s) in the lead-up to COP30 in 2025. The NDC 3.0s are supposed to reflect how countries plan to address outcomes from the GST1. While including 2030 renewable capacity targets is not mandatory, it would be a practical way to explain how GST1 outcomes were considered, which is required in the new NDCs. Thus, the NDC 3.0s would make it possible to assess government approaches and contributions towards meeting the common goal.

Our review of the UNFCCC registry reveals that only 57 of the 196 Parties to the Paris Agreement had submitted NDC 3.0s as of 28 September 2025, accounting for only 23% of CO_2 emissions from fuel combustion. Of these, 11 are advanced economies (19% of global CO_2 emissions from fuel combustion), while the remaining 46 are developing and emerging countries (4%).

Encouragingly, most submissions (54) mention renewable energy, recognising that it has a role to play in lowering GHG emissions. However, only 14 explicitly acknowledge the COP28 tripling pledge, and just 5 identify their renewable capacity ambitions for 2030, totalling 80 GW. This is less than 1% of the 11 500 GW needed to meet the global tripling target by the end of the decade.

Shares of fuel-combustion CO_2 emissions in 2023 covered in NDC 3.0s (left) and country progress in submitting updates as of 28 September 2025 (right)



Notes: NDC = Nationally Determined Contribution. On 20 January 2025, US Executive Order 14162 on Putting America First in International Environmental Agreements withdrew the United States from the Paris Climate Agreement, with official notification submitted to the UN on 27 January 2025, making the withdrawal effective on that day.

However, the absence of a 2030 renewable capacity target does not necessarily indicate that a country lacks a plan to accelerate renewable capacity. Some countries have set their ambitions for 2035 instead of 2030, while others have expressed their renewable electricity targets in other units (e.g. share of power generation) or have embedded them within broader net-zero strategies.

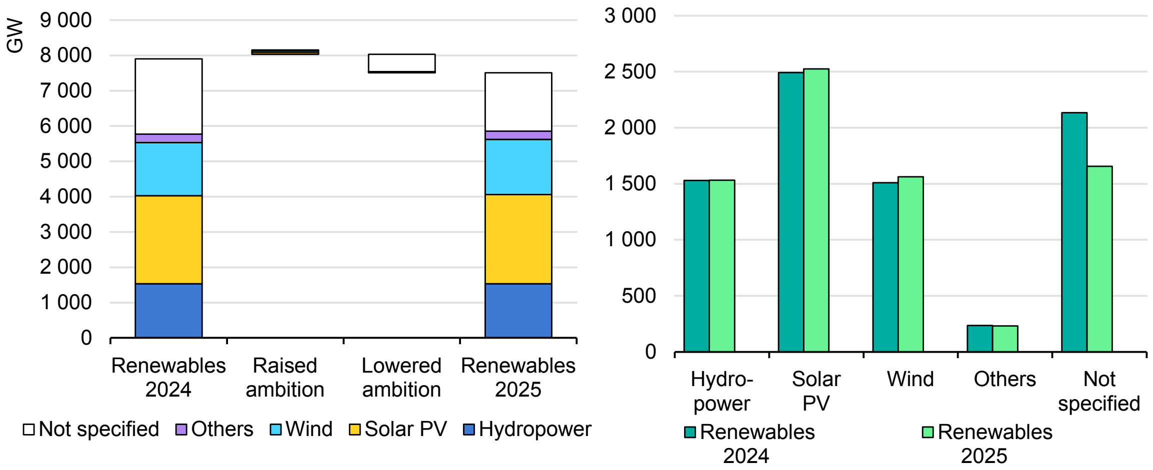
Additionally, at the UN climate summit in New York on 24 September 2025, a further 10 countries verbally announced their intention to submit NDC 3.0s to the UNFCCC registry, but they have not yet done so. For example, China announced that it would increase its solar and wind capacity to three times the 2022 level (to around 3 600 GW) by 2035 under its planned NDC.

While most countries are raising their renewable electricity goals outside of NDCs, overall global ambition is slightly lower than in last year's analysis

Although countries have so far been slow to submit their updated NDCs, many of their national plans already contain renewable capacity ambitions for 2030 or another indicator that can be used to estimate it, which could be used in their NDC 3.0. In fact, overall country ambitions for installed renewable power capacity in 2030 total roughly 7 500 GW. While this is 5% lower than our 2024 assessment, not all countries or technologies are following this trend.

Since October 2024, nine countries have updated their national ambitions for 2030. However, only six made significant changes (greater than 1%). Of these six, three raised their ambitions, while the other three lowered them.

Global renewable electricity capacity ambitions by technology



Notes: Ambition changes correspond to 23 countries that represent 83% of global installed renewable capacity in 2024.

The majority of the decrease in global ambition comes from the United States, where policy changes in January 2025 revoked the 2021 executive order that aimed for 100% clean energy by 2035. Other downward changes to 2030 goals come from Indonesia's latest National Electricity Plan (RUKN 2025-2060), which is 20% less ambitious than its 2019 plan due to lower aims for solar PV. The latest energy plan for the Philippines (2023-2050) also envisions slightly lower installed capacity by 2030 than its previous plan, for both the reference and the clean-energy scenario. However, reductions in total capacity do not always reflect diminished ambition, as some declines stem from revised assumptions on demand growth or technology performance. For example, the Philippines lowered its capacity figures but still maintains its previous ambition for a 35% share of renewables by 2030.

Conversely, the United Kingdom, Viet Nam and South Africa have raised their ambitions for renewable power capacity in 2030. While this boosts the overall global ambition by just 1%, each country's revision represents a substantial increase in its own goals (at least 20%) compared with previous plans.

The largest revision came from Viet Nam, which published its Eighth Power Development Plan (PDP8) in April 2025, raising expected renewable capacity additions by almost 40% from its previous strategy. This increase reflects higher anticipated GDP, power demand growth and electricity exports. In the United Kingdom, the government has set its first-ever formal targets for solar PV and onshore wind, raising the country's overall ambition by 24% and boosting the offshore wind target from 40 GW to 43 GW. In South Africa, the newly released Energy Master Plan outlines an annual target of 3-5 GW of renewable additions by 2030 to stimulate local manufacturing and industrial development – almost a 30% increase from its 2023 Integrated Resource Plan.

Technology ambitions have also been revised. Solar PV aspirations have climbed overall, led by Vietnam – which doubled its PV target – and the United Kingdom, which set a national PV target for the first time. These gains offset reductions in Indonesia, the Philippines and South Africa. Meanwhile, wind ambitions have risen for all countries (including South Africa, the United Kingdom, Vietnam, Indonesia and the Philippines), with higher offshore wind goals playing a key role in both the United Kingdom and the Philippines.

Policy changes in the last year have had mixed impacts on renewable electricity deployment, but countries are increasingly focusing on cost-effective integration

The policy and regulatory changes countries have been introducing since October 2024 have had varying objectives: to boost growth to realise long-term ambitions; to procure affordable renewable power; and to ensure cost-effective system integration. The impacts of these measures on our forecast vary, depending on objective, design and surrounding policy environment.

The impact of policy changes on our forecast can be assessed across two dimensions: their quantitative effect on deployment projections, and their qualitative contribution to broader policy objectives. Some forecast impacts are clearly classified as positive because they directly stimulate capacity growth or improve project economics. Others may result in a lower or unchanged forecast but are still considered positive if they advance cost-effective market and system integration. Conversely, the impacts of policy changes that create uncertainty, weaken investment incentives or lack supporting measures are assessed more negatively, even if their quantitative effect appears limited.

Key policy developments and their impact on the renewables forecast

Country	Date adopted	Measure	Description	Forecast impact
India	2024	PM Surya Ghar: Muft Bijli Yojana	Provided subsidies for 60% of investment cost for distributed systems	↑
Viet Nam	2024	Decree 57/2025/ND-CP	Allowed corporate PPAs for the first time	↑
European Union	2024	Electricity market reform Regulation (EU) 2024/1747	Required contracts for difference to be used for renewable electricity by 2027	→
Germany	2025	Solarspitzengesetz (Solar Peak Act)	Suspended subsidies during negative price hours; capped exports to 60% unless smart meter installed	→
Italy	2025	Ritiro Dedicato	Switched from net metering to net billing	↓
Netherlands	2024	Wet beëindiging salderingsregeling	Switches from net metering to net billing	↓
Poland	2024	Mój Prąd 6.0	Introduced requirement for storage to be eligible for CAPEX subsidy	→
China	2025	NDRC Reform No. 136 electricity market reform	Required contracts for difference to be used for renewable electricity	→
United States	2025	One Big Beautiful Bill	Phased out tax credits for solar and wind	↓
France	2025	S21 tariff reform	Reduced rebates and cut net-billing remuneration rates for PV <500 Kw	↓

Legend: Forecast impacts are classified according to two factors: policy objective, and quantitative result on the forecast. Arrow directions indicate quantitative impacts on the forecast: up = upwards revision; down = downwards revision; and horizontal = no change to forecast. Colours indicate qualitative impacts (i.e. changes to objectives, consumer confidence, cost, etc.) on deployment: green = positive; orange = uncertain; and red = negative.
Note: In Viet Nam, direct PPAs were first introduced in July 2024 with Decree 80/2024/ND-CP, later replaced in 2025 by Decree 57/2025/ND-CP, which clarified terms and conditions for producers and consumers.

The first group of policy changes are those that result directly in upward revisions to the forecast and are considered to have a positive impact because they improve project economics or offer new market opportunities. These include new investment subsidies, remuneration schemes and regulatory changes that allow for merchant or corporate procurement. The most prominent example is India's new capex subsidies that reduce investment costs by 60% for residential PV, underpinning our 40% upwards revision for distributed solar PV. Higher growth is also expected as a result of Viet Nam's electricity market reform, which allows the use of corporate PPAs for the first time.

Another positive impact resulting from a policy development is the 2024 EU electricity market design reform, under which all new support for utility-scale renewables must be awarded through competitive contracts for difference by 2027. This provides a cost-effective route to market integration while giving developers the long-term revenue stability needed for derisking. However, its quantitative impact on our forecast is minimal, as most countries except Germany already have contracts for difference in place.

Meanwhile, a second group of policy changes that aims for cost-effective system and market integration while attempting to minimise consumer impacts does not result in an upwards revision. For example, to reduce grid congestion and negative prices, Germany introduced its Solar Peak Act in February 2025 to incentivise self-consumption and prevent the temporary production of excess generation at peak production times. The reform removes subsidies during negative-price periods and caps grid exports to 60% until smart meters are installed. Nevertheless, these changes are not expected to pose a downside risk to the forecast because the policy also includes mechanisms to help maintain the business case, for example compensation for missed subsidies during negative-price periods after the support scheme ends, and incentives to switch to the new scheme. This forecast impact is therefore considered positive because it aims to improve grid and market integration of renewables while maintaining economic attractiveness.

Conversely, while lower growth is expected in Italy and the Netherlands with the phase-out of net metering, these impacts are considered positive because the goal is to incentivise self-consumption while maintaining support by switching to net billing, which would reduce public and system integration costs overall.

Other impacts resulting from recent policy developments are classified as neutral because, while the policy objective is positive, the magnitude of its impact remains uncertain and will depend on the effectiveness of accompanying or enabling measures. For instance, while China's shift from feed-in tariffs to competitive auctions is a constructive step towards market-based pricing, it contributes to a downward forecast revision because perhaps not all projects will find auction prices or the emerging spot markets attractive. However, the weight of the impact hinges on spot markets being operational and on curtailment risks increasing.

Likewise, policy changes in Poland require all new PV systems to include a battery to qualify for CAPEX subsidies. While this measure is intended to incentivise system-friendly self-consumption and reduce grid congestion, its impact is uncertain since its success will depend upon sufficient support for batteries to keep deployment attractive.

In some cases, policy changes reduce investment incentives without providing a clear alternative pathway, which also poses downside risks for the forecast. The most significant example is the US One Big Beautiful Bill, which phased out tax credits for wind and solar earlier than expected, leading to a downward forecast revision. Similarly, France's SR1 tariff reform reduced both remuneration and rebates for distributed PV, raising concerns over whether the goal is better system integration or simply cost-cutting.

Procurement

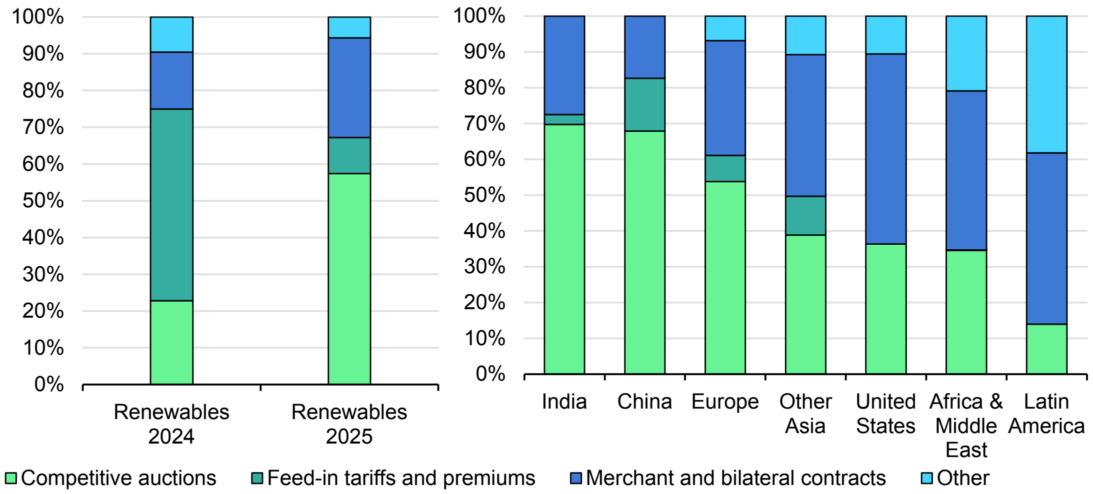
Competitive auctions and market-based procurement are increasingly driving global utility-scale renewable electricity expansion

Competitive auctions are now the main procurement mechanism of global utility-scale renewable deployment, accounting for almost 60% of gross capacity additions expected during 2025-2030 – up from less than 25% in the 2024 forecast. This marks a major shift from last year's analysis, when feed-in tariffs and premiums were still the dominant mechanism (but now they represent just 10% of growth). Unlike feed-in tariffs and premiums, where the government sets offtake prices, competitive auctions let developers bid for the level of remuneration they receive, ultimately leading to lower costs.

This shift reflects China's 2025 policy reform, which phased out fixed tariffs for solar PV and wind benchmarked to provincial coal prices, replacing them with competitive auctions. China's transition signals in a step-change in the renewables' market maturity, illustrating that global utility-scale growth no longer relies on administratively-set government set-tariffs. For the first time, competitive mechanisms—not government-set tariffs—will determine the offtake prices for most new capacity additions.

Competitive auctions are now the main procurement type in China, India and Europe, accounting for more than half of renewable capacity growth over 2025-2030. Together, these three markets represent around 85% of global tendered capacity over the forecast period. Most schemes take the form of contracts for difference, mandated by both China and the European Union, while in the United States, utilities mainly conduct auctions to meet state RPS obligations. In other regions such as Latin America, Africa and the Middle East, auctions play a smaller role, with other procurement mechanisms more prominent.

Gross renewable utility-scale capacity additions by procurement type, 2025-2030



Notes: "Merchant and bilateral contracts" refers to projects that gain revenues from the wholesale spot market, corporate PPAs, or unsolicited bilateral contracts with utilities. "Other" refers to other procurement mechanisms, including state-owned utility projects, green certificates, or mechanisms not elsewhere specified. In the United States, "Competitive auctions" are held by utilities to meet state renewable portfolio standards.

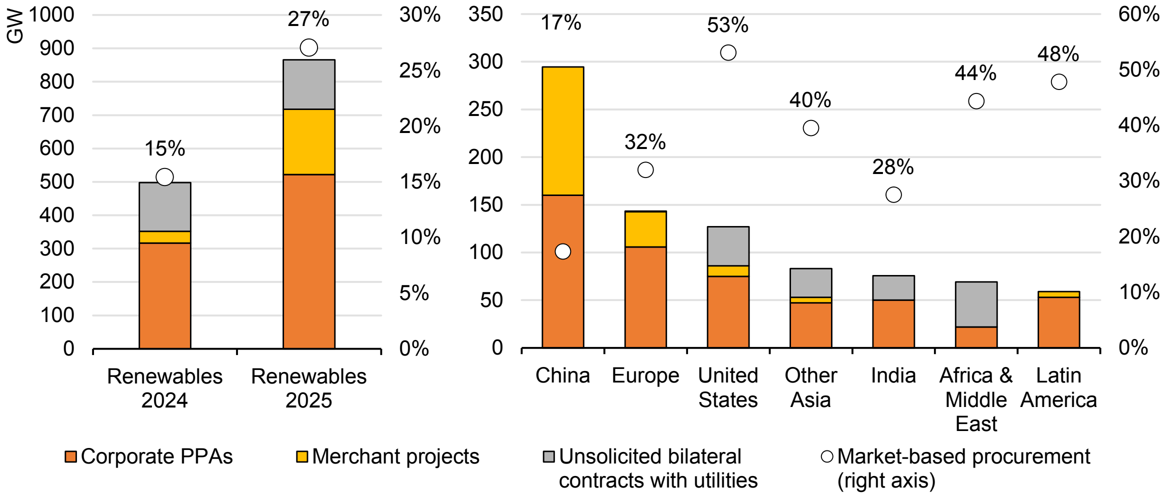
Market-based procurement mechanisms (i.e. project revenues relying primarily on wholesale spot markets (merchant), corporate purchase power agreements (PPA) or unsolicited bilateral deals with utilities) are also becoming more important. Their role in driving renewable capacity deployment is increasing, accounting for 28% of the growth in the current forecast compared to just 15% in last year's analysis. This stems largely from upwards revisions for China, owing to its power market reforms, and for Europe, where installations have been increasing.

In China, NDRC Reform No. 136, which requires provinces to implement short-term spot markets and strengthen medium- and long-term contractual markets, spurs higher market-based deployment. As a result of this change, our forecast now includes nearly 300 GW of corporate PPA and merchant projects, representing about 17% of China's utility-scale growth.

For Europe, we have revised the forecast for market-based procurement up to nearly one-third of growth, compared with 18% in last year's outlook. Several factors influenced this change: larger late-stage pipelines of merchant and corporate PPA projects in Spain and Portugal; faster-than-expected installations from corporate PPAs in Germany, Italy and Poland in 2024 and the first half of 2025; and increased merchant deployment in Türkiye, supported by projects shifting between auctions and market revenues, and by new pumped-storage projects.

In some regions, the share of market-based procurement exceeds the global level. In the United States it accounts for more than 50% of utility-scale growth mostly from corporate PPAs, propelled by rising electricity demand from data centres and AI, particularly in ERCOT. In Africa and the Middle East the share nearly reaches 45% largely from Saudi Arabia's National Energy Strategy, which mandates that 70% of renewable capacity be contracted through unsolicited bilateral PPAs, South Africa's reliance on corporate PPAs to reduce the impacts of load-shedding; and several hydropower stations in Nigeria are being developed under unsolicited bilateral contracts with the utility.

Gross utility-scale renewable capacity additions for market-based procurement by region, 2025-2030



In Latin America, market-based procurement represents almost half of forecast growth, but its share has declined from last year. The downward revision reflects growing concerns about curtailment and transmission constraints in Brazil and Chile, as well as the rising role of state-owned enterprises in Mexico. Under Mexico's 2024-2030 National Energy Strategy, at least 13 GW of new power investment is earmarked for the state utility, which is guaranteed a 54% share in public-private partnerships – reducing space for unsolicited bilateral or merchant projects.

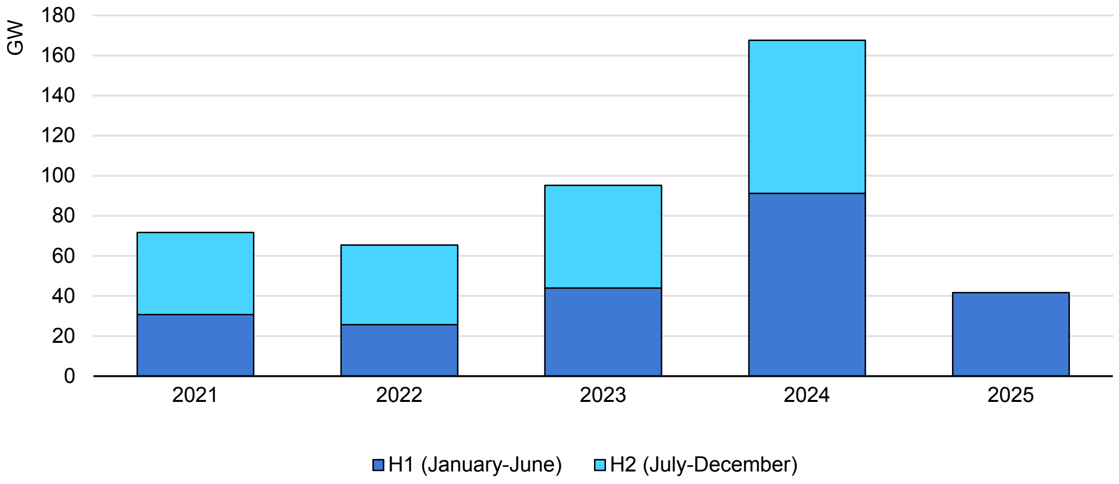
About 40% of utility-scale growth in Asia Pacific (excluding India) is expected from market-based procurement mechanisms. Corporate PPAs are supported by Viet Nam's new regulation allowing third-party sales; Thailand's pilot corporate PPA programme; higher industrial tariffs in Korea; rising retail prices in Japan; and growing net-zero commitments from mining, steel and aluminium firms in Australia. Corporate PPA use is also increasing in India, largely from the cement sector's decarbonisation commitments. Elsewhere in Asia, unsolicited bilateral contracts with utilities are frequently used for large hydropower projects.

Competitive auctions

After the exceptional jump in 2024, competitive auction volumes returned to average in 2025

In the first half of 2025, countries used competitive auctions to award 42 GW of renewable energy capacity globally. While this aligns with the six-month averages of 2021-2023, it marks a sharp decline (-54%) from the record-high capacity awarded during the same period last year.

Global awarded capacity in competitive renewable energy auctions, 2021-2025



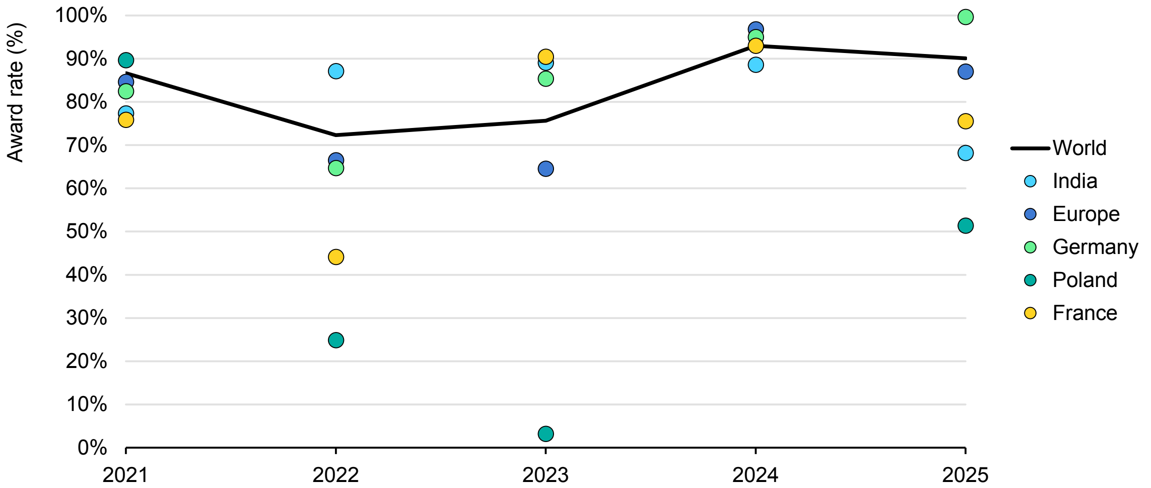
Since 2021, an average of 40-55% of end-year capacity has typically been auctioned between January and June. If this trend continues, global auction capacity could reach around 75-105 GW by the end of 2025.

Design elements, macroeconomic conditions, permitting pace and land and grid availability continue to be key factors impacting developer interest and participation in auctions. Award rates have fluctuated year-on-year, with the lowest occurring in 2022. High commodity prices, escalating investment costs and inflation, combined with relatively low ceiling prices in auctions, caused the award rate to drop to 72% that year.

However, with the modification of many auction rules to reflect evolving macroeconomic conditions, award rates have since been rising, reaching 93% in 2024 and remaining stable. In the first half of 2025, around 90% of the 46 GW of auctioned capacity was successfully awarded.

For India, the auction award rate dropped to 68% in 2025, after having been stable at around 90% between 2022 and 2024. Of the two key reasons for this decrease, the first is concern about the financial health of offtakers. Some auctions are conducted by DISCOMs without the financial backing of central agencies such as SECI, raising developer concerns about delayed PPA signings and payment risks. Second, requirements in some hybrid auctions can be difficult to meet at the ceiling price offered. Additionally, grid connection queues and land access issues have negatively impacted auction results, particularly in the wind sector.

Competitive renewable energy auction award rates globally and in selected countries, 2021-2025



Note: 2025 values are for January to June only.

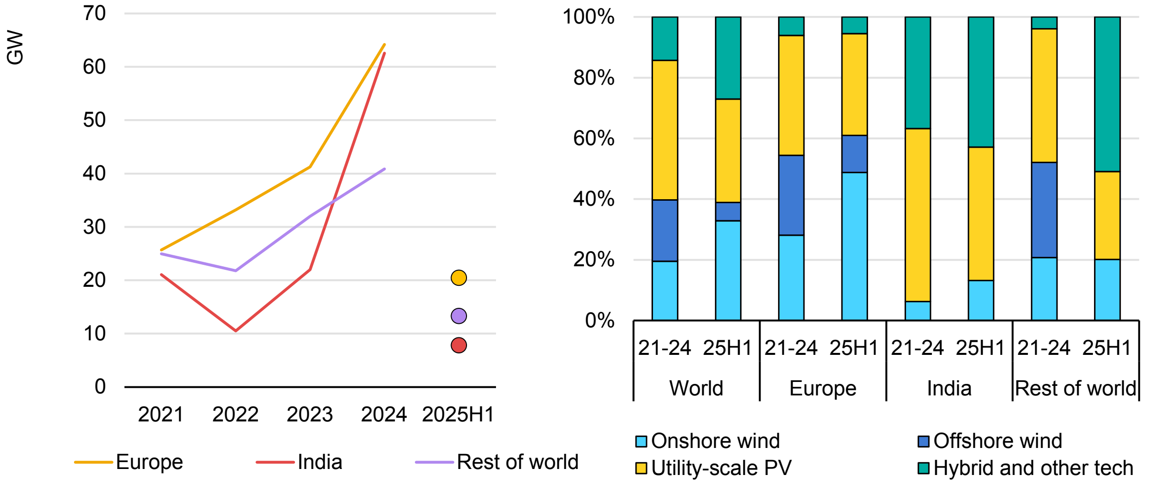
In contrast, auction capacities offered in Europe since 2024 have been almost fully awarded, rising from around 65% in the previous two years. In fact, tenders were almost completely awarded in Germany (12.6 GW) and Türkiye (2 GW). Subsequently, Poland's 2025 contract-for-difference (CfD) auction awarded around 50% of the electricity generation offered, marking a significant recovery from the low results of 2023. Although the tariff ceiling and other auction parameters remained unchanged from 2024, record-low PV module prices and continued uncertainty about future revenues (without a CfD) encouraged strong developer participation.

Europe remains the leading region for renewable energy auctions despite a slowdown in awarded capacity

In the first half of 2025, Europe maintained its position as the largest regional market for competitive renewable energy auctions, awarding almost half of global volumes. Although the region's awarded capacity declined by 43% compared with the same period in 2024, the 20.5 GW awarded still exceeds the historical average of six-month periods prior to 2024.

Germany accounted for around 60% of Europe's volumes, followed by France with 3.6 GW. Türkiye resumed auctions for the first time since 2022, awarding 2 GW of onshore wind and solar PV. Poland followed with 1.8 GW, and awarded capacity totalled 0.6 GW in Austria. However, several European countries that had awarded large volumes in the first half of 2024 (the United Kingdom, the Netherlands, Bulgaria, Italy and Norway) had not conducted auctions by mid-2025. These countries accounted for nearly 40% of the region's awarded capacity in the same period last year.

Awarded capacity in competitive auctions by region (left) and technology (right)



Notes: H1 = January to June. "Hybrid and other tech" include auctions for hybrid projects (onshore wind and utility-scale solar PV), as well as biomass, distributed solar PV, hydropower and geothermal projects. "Offshore wind" includes auctions that allocate the seabed lease and support jointly, as well as seabed lease auctions (which are not followed by a support auction). Auctions for seabed leases followed by support auctions are included by the time the second auction is held.

Meanwhile, India awarded around 8 GW in the first half of 2025, representing close to one-fifth of global awarded capacity. However, this marks a 76% decline compared with 2024. The slowdown stems largely from lower demand from DISCOMs, which has delayed the finalisation of PPAs with already-awarded projects. These delays have impeded the launch of new auction rounds and contributed to lower interest from potential bidders.

In other regions, the Philippines awarded around 6.7 GW of hydropower capacity (6.4 GW of pumped storage hydropower and 0.3 GW of conventional hydropower) in 2025, Kazakhstan procured 1 GW in an onshore wind and storage auction and almost 0.4 GW of standalone onshore wind and solar PV, and Malaysia concluded an auction for almost 2 GW of solar PV capacity.

Awarded onshore wind capacity surged in the first half of 2025, matching solar PV volumes for the first time

Awarded auction volumes in the first half of 2025 showed a significant shift in technology shares. From 2021 to 2024, utility-scale PV accounted for nearly half of global capacity awarded, totalling around 180 GW. During the same period, both onshore and offshore wind contributed about 20% each, while hybrid projects and other technologies made up the remaining 14%.

In the first half of 2025, onshore wind accounted for around 33% of global auction volumes, reaching 14 GW, the highest awarded capacity in any six-month period before 2024, and – for the first time – similar to awarded solar PV capacity.

In India, standalone onshore wind auctions remained limited, contributing only about 13% of the total. However, awarded volumes grew significantly in Europe and Eurasia. This surge results mainly from permitting condition improvements that addressed years of undersubscribed auctions, especially in Germany (7.5 GW awarded). Türkiye awarded 1.2 GW, and France approximately 0.9 GW, with further volumes granted in Austria and Poland. Outside of Europe and India, countries awarded almost 3 GW, among others Kazakhstan, Canada and Serbia.

Utility-scale solar PV made up one-third of global auction awards in H1 2025, totalling over 14 GW, a 63% drop from last year, likely due to more merchant projects. In Europe, solar held a 34% share, led by Germany and Poland. India's total awards fell about 80%, but solar still reached almost 45%, in line with past years. Elsewhere, the PV share stayed below 30%, though it is expected to rise with large tenders later in 2025, including 8 GW in the Philippines.

Offshore wind auction volumes also plummeted to 2.5 GW in the first half of 2025, making up just 6% of global awarded capacity, compared with 21 GW during the same period last year. In awarding a 1-GW seabed lease in the North Sea, Germany was one of two countries to hold an offshore wind auction for the seabed lease and potential support combined by mid-2025. The auction attracted two zero-cent bids, triggering a dynamic bidding round that resulted in payments of EUR 180 000/MW to the government (80-90% lower than in the previous two years), reflecting reduced competition. France was the other country, awarding a seabed lease and a CfD of over EUR 66/MWh for a 1.5-GW offshore wind farm.

Also in the first half of 2025, around 4 GW of seabed leases were awarded, with support auctions expected to follow. Estonia tendered the seabed lease right of the Saare 1 area for a 900-MW project at a price of around EUR 1 400/MW, with an auction for support expected soon. Similarly, the United Kingdom awarded 3 GW of seabed leases for floating offshore wind, with another 1.5 GW likely to be awarded later this year.

Auction activity is expected to accelerate in the second half of 2025. In the Asia Pacific region, Korea awarded almost 0.7 GW of offshore wind projects, while the Philippines is planning its first offshore wind auction for 3.3 GW. In Europe, Ireland is advancing the 0.9-GW Tonn Nua project auction and the United Kingdom is preparing for CfD Allocation Round 7 later in 2025. Poland is preparing to conduct its first offshore wind support auction in December 2025 for a total of 4 GW.

At the same time, several offshore wind auctions were cancelled due to a lack of participation. Rising costs and overall uncertainty, paired with the absence of revenue stabilisation mechanisms such as contracts for difference, led to low interest from project developers. In June 2025, Estonia cancelled the Saare 7 seabed lease auction after both bidders failed to meet prequalification requirements. In August 2025, no bids were submitted in Germany's auctions for two predeveloped sites totalling 2.5 GW of potential capacity.

Similarly, no bidders participated in France's second offshore wind auction in 2025. Denmark cancelled three auctions, while India abandoned two – one for 4 000 MW of seabed leases and the other for rights and support for a 500-MW offshore wind project in Gujarat – because of limited interest from developers.

Hybrid projects and other technologies made up the remaining 27% of awarded capacity in 2025. In India, hybrids accounted for nearly half of all awarded volumes, continuing the trend from 2024. In Europe, other technologies maintained a stable 5% share, including 0.8 GW of distributed PV (in France, Germany and Poland) and 0.3 GW of biomass and CHP capacity (mostly in Austria and Germany). Outside of Europe and India, shares of these technologies remained small except in Asia Pacific in 2025, where it exceeded 75%, owing almost entirely to the 6.7 GW of hydropower awarded in the Philippines.

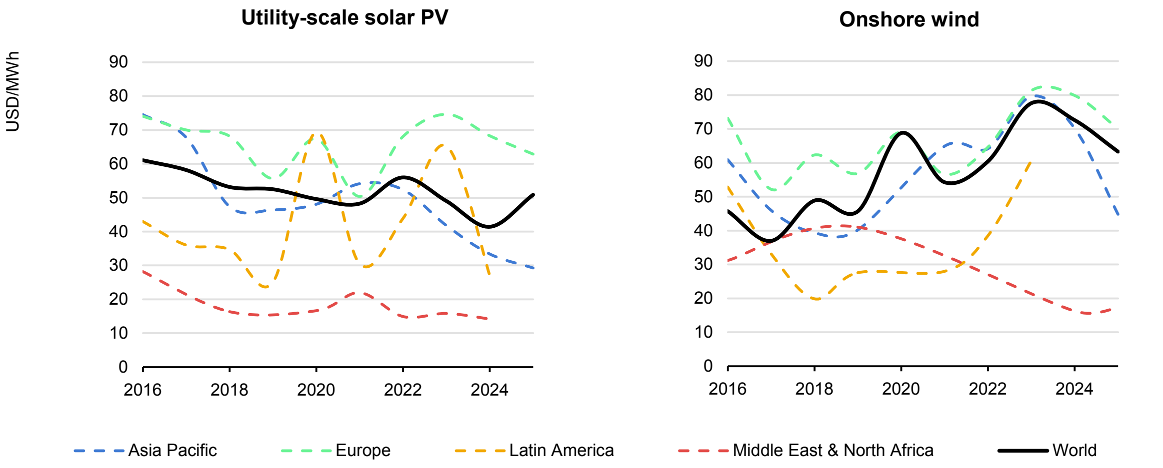
Global auction prices for solar PV are rising with regional shifts in capacity awards, while onshore wind begins to decline

Global average utility-scale solar PV auction prices fell to a historic low of around USD 41/MWh in 2024, mostly because high shares of capacity were awarded in the Asia Pacific, Middle East and Latin America regions, where very good resource availability results in comparatively low prices. For instance, India awarded more than 23 GW at around USD 33/MWh; Chile and Colombia allocated around 5.5 GW at an average price of USD 25-30/MWh; and Saudi Arabia's almost 4 GW was priced mainly belo--w USD 15/MWh. In contrast, Europe – one of the higher-priced regions – awarded around 17 GW of capacity at an average price of USD 68/MWh.[6]

[6] In general, auction prices are not necessarily comparable across markets due to differences in contract duration, auction design and revenue stabilisation mechanisms. Price levels should therefore be interpreted and compared with caution, but they nevertheless illustrate broader global trends in technology pricing.

In the first half of 2025, awarded prices in both Asia Pacific and Europe had fallen by around 10% from last year. However, the share of higher-priced regions in awarded volumes increased (to almost 7 GW in Europe, compared with around 6 GW in Asia Pacific) without substantial auctions in other areas. Thus, even though module prices have dropped, the shift in awarded volumes towards higher-priced countries has raised the global average auction price of solar PV to USD 51/MWh – an increase of around 23% from 2024.

Weighted average utility-scale solar PV and onshore wind auction prices by region, 2016-2025



Notes: Asia Pacific excludes China. 2025 values are for January to June only.

Global average auction prices for onshore wind have been rising from their lowest-ever levels in 2017. After peaking in 2023 at USD 78/MWh, they fell to around USD 64/MWh in the first half of 2025. This year's decline resulted from lower auction prices in Europe (the world's largest onshore wind auction market) and significant volumes awarded in Eurasia and the MENA region. In Europe, onshore wind auction prices fell by around 12%, mostly due to a price drop in Germany.

A closer look: The rising use of firm-capacity renewable energy auctions is improving electricity security

By the first half of 2025, more than 10 countries had conducted renewable energy auctions for firm or dispatchable capacity involving solar PV and/or onshore wind,[7]

[7] In this subsection, "firm-capacity auctions" are auctions for projects that combine a solar PV and/or onshore wind component with storage (such as batteries, pumped-storage hydro, etc.) or are hybrid, combining two technologies (in most cases solar PV and onshore wind). Other technologies such as biomass, hydro and CSP can also provide firm capacity, but their awarded auction volumes are significantly smaller.

motivated by falling energy storage costs and the need to integrate increasing amounts of variable renewables. Egypt was the first country to hold a firm-capacity auction for a solar PV project combined with storage in 2016. In 2018, India conducted its first auction for combined (i.e. hybrid) solar PV and onshore wind projects, and in 2020 Germany and Portugal were the first countries in Europe to implement firm-capacity auctions for renewable energy projects linked with battery storage.

Rapidly growing shares of variable renewables in many countries increase system integration challenges, requiring additional system flexibility. Traditionally, flexibility has been provided mainly by hydropower and fossil fuel (gas-fired) plants, as their output can be adjusted quickly to balance supply and demand. However, with lower battery costs and the co-location of multiple variable and dispatchable renewables such as solar, wind, hydropower and geothermal, hybrid systems can now enhance dispatchability. Renewable energy auctions that require "firm" or "dispatchable" generation profiles are therefore becoming a key policy framework enabling developers to provide flexibility.

Firm-capacity auction schemes offer multiple advantages. They can enhance electricity security by incentivising the development of increasingly dispatchable wind and solar projects that are able to provide essential balancing and ancillary services. Thus, they can help meet rising industry demand for dispatchable renewable electricity. Furthermore, by encouraging the co-location of renewables, these schemes can also optimise grid capacity use, making the most of existing or new infrastructure. Additionally, they can reduce curtailment by ensuring that variable renewable output is utilised more effectively, reducing waste. Over time, increasing dispatchability can also improve the economics of wind and solar systems by providing them access to higher capture prices.

However, firm-capacity auctions often lead to higher prices than standalone renewable energy auctions. They also require a more complex auction design and additional regulations for the technical configuration of projects, especially for storage system charging and dispatch.

Overview of firm-capacity renewable energy auctions, including technical requirements

Country	Scheme	Storage requirements
Australia (renewable source and storage, or standalone storage)	• Capacity Investment Scheme (CIS), targeting 9-14 GW of clean dispatchable capacity • 2.1 GW of renewables combined with storage awarded in CIS Tender 1 and Tender 2	• Minimum size of 30 MW • 2 MWh/MW storage capacity

Country	Scheme	Storage requirements
Bulgaria (renewable source and storage)	• Support for new electricity production from renewables and storage with installed capacity of 200 kW to 2 MW, and for new electricity production from renewables and storage with installed capacity of over 200 kW • 3.1 GW awarded in 2024	• Minimum 30% of installed capacity of the renewable power project • Maximum 50% • Not less than 1 MW
Germany (solar PV and onshore wind with storage, or hybrid projects)	• Innovation auctions • 3.6 GW awarded since 2020	• Minimum 25% of project capacity • 2 MWh/MW storage capacity
India (solar PV and onshore wind hybrid projects)	• Guidelines for Tariff-Based Competitive Bidding Process for Procuring Power from Grid-Connected Wind, Solar and Hybrid Projects • More than 50 GW awarded since 2018	• Capacity of both wind and solar PV components needs to be at least 33% of total contracted project capacity • Minimum annual capacity utilisation factor of at least 33%
India (renewable project and storage)	• Guidelines for Tariff-Based Competitive Bidding Process for Procuring Firm and Dispatchable Power from Grid-Connected Renewable Energy Power Projects with Energy Storage Systems • More than 7 GW awarded since 2020	• Projects need to be able to provide electricity during peak times • Capacity factor can be up to 90%, depending on the auction
Kazakhstan (onshore wind and storage)	• RES auction bidding • 1 GW awarded in 2025	• 30% of the installed capacity of the renewable power project • 2 MWh/MW storage capacity
Morocco (solar PV and storage)	• Noor Midelt II and III	• 400 MW of solar PV and 400 MWh of storage
The Philippines (solar PV and storage)	• Green Energy Auction – Round 4 • 1.1 GW to be awarded in 2025	• Minimum 20% of project capacity • 4 MWh/MW storage capacity
Portugal (renewable project and storage)	• Renewable capacity auction • 483 MW of renewable projects combined with storage awarded in 2020	• Minimum 20% of the project capacity • 1 MWh/MW
Spain (renewable project and storage)	• Renewable Energy Economic Regime (REER) • No renewable project combined with storage awarded	• Minimum 2 MWh of storage for each MW of project capacity

Country	Scheme	Storage requirements
Thailand (solar PV and storage)	• Procurement of electricity from renewable energy in the form of [Feed-in Tariff (FiT) 2022-2030](#) for groups with no fuel costs • 1 GW awarded in 2023	• 9:00 am to 4:00 pm: 100% of the MW capacity specified in the PPA • 6:01 pm to 6:00 am: 60% of the MW capacity specified in the PPA for two hours (or more as ordered by the offtaker) • Other times: no minimum requirement, and the offtaker will purchase all electricity generated up to 100% of the MW capacity specified in the PPA

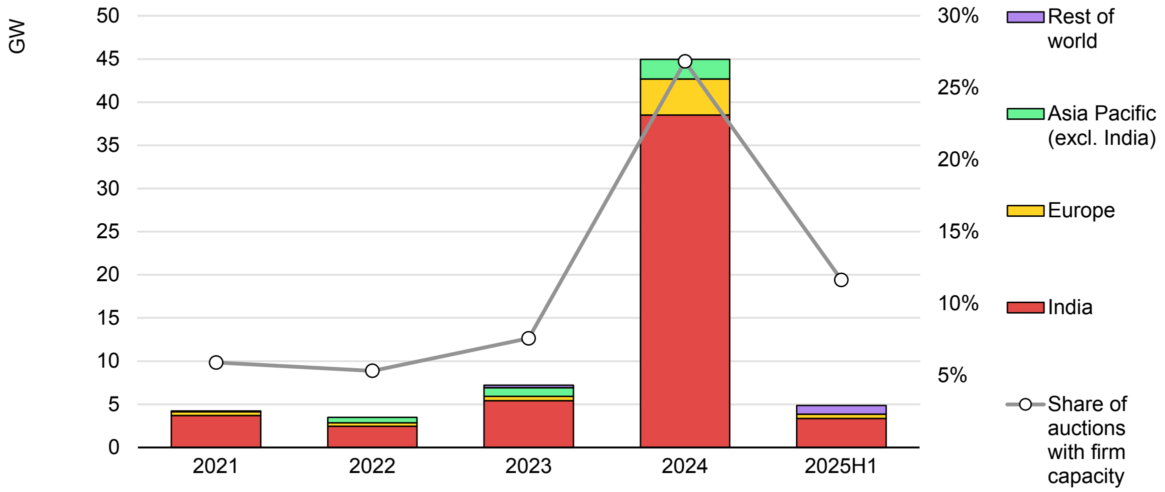
Firm-capacity auctions are gaining traction, yet the market is cooling after a record year in 2024

In 2024, governments awarded 45 GW of renewable electricity capacity through firm-capacity auctions, representing over one-quarter of all renewables awarded worldwide. This is a significant increase from 2021-2023, when firm auctions made up only 5-8% of global auction volumes. India and Europe were mainly responsible for the sharp acceleration last year, with awarded capacity expanding more than sevenfold in India and ninefold in Europe.

Overall, governments have awarded 65 GW of firm renewable capacity since 2021. India has awarded more than 50 GW – around 80% of all firm capacity worldwide. Europe represents almost 10% at around 6 GW, of which Germany and Bulgaria contributed roughly half each. Asia Pacific added around 6% (almost 4 GW), with three-quarters awarded in Australia and the rest in Thailand. The remaining 2% stems from countries in other regions, such as Kazakhstan and Argentina.

The share of firm-capacity auctions in national renewable tender volumes varies widely across countries. Since 2021, Bulgaria and Peru have been awarding all their renewable capacity through firm auctions. However, in most other countries with such schemes, firm-capacity auctions accounted for just 20-30% of awarded volumes. In India, firm-capacity auctions have been behind over 40% of total awards since 2021, while Germany, in contrast, has allocated less than 4% through them.

Global awarded capacity in auctions with firm capacity by region, 2021-2025



In the first half of 2025, almost 5 GW of firm renewable capacity were awarded – around only one-quarter of the 19 GW awarded in the same period last year. This lower awarded capacity is connected to an overall decline in renewable auction volumes worldwide. Despite this trend, the share of firm-capacity auctions is roughly in line with pre-2024 levels.

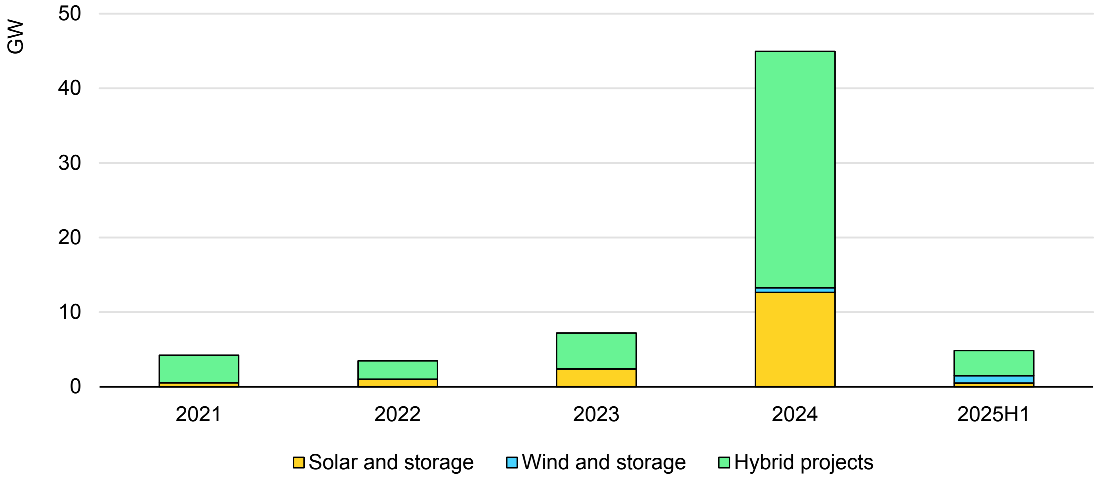
The decline in firm-capacity auction volumes in 2025 results mainly from a sharp drop in India, where awarded capacity fell by 75% compared to the first half of 2024. This reduction reflects lower demand from DISCOMs, resulting in delays in finalising PPAs for already-awarded projects. Volumes also fell significantly in Europe, by around 86%, with Germany being the only country to hold a firm-capacity auction so far this year. Ireland has included hybrid and storage projects in its ongoing RESS 5 auction.

In the Asia Pacific region, no firm auctions have yet been concluded in 2025, although the Philippines launched a round including 1.1 GW of solar PV with storage, expected to close later this year. Despite the overall global decline, the impact has been partially offset by 1 GW of firm capacity awarded in Kazakhstan.

Firm-capacity auctions can be designed in different ways. They may be structured as hybrid auctions, allowing combinations of multiple renewable energy sources. Alternatively, they can be technology-specific, targeting particular combinations such as solar plus storage or wind plus storage. Hybrids make up 71% of all awarded firm capacity since 2021, exclusively awarded in India.

Solar and storage represent more than 25% (roughly 17 GW), with India awarding more than 40% of this capacity (around 7 GW), followed by Germany (3 GW) and Bulgaria (3 GW). In contrast, only 1.6 GW of onshore wind and storage projects have been awarded in auctions since 2021: 1 GW in Kazakhstan and 0.6 GW in Australia, and two smaller projects in Argentina and Bulgaria.

Awarded capacity in firm-capacity auctions by project type, 2021-2025



Prices are higher for firm capacity, but differences across countries are significant

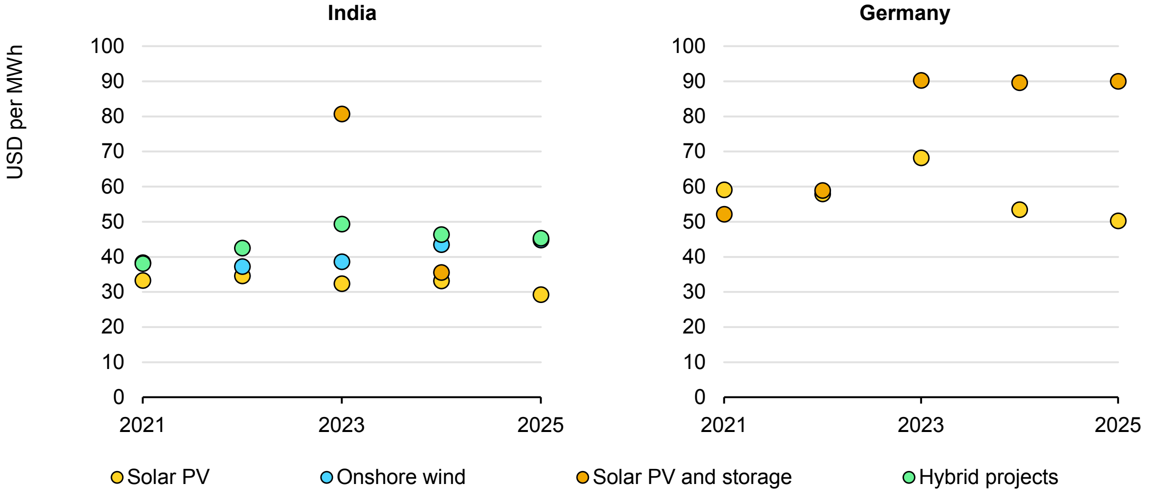
Between 2021 and 2025, firm-capacity auctions delivered an average awarded price of USD 47/MWh. In the same period, the global average auction price for standalone solar PV was USD 48/MWh, and for onshore wind it was USD 67/MWh. The global average for firm-capacity auctions is slightly inferior largely because most capacity was awarded in India, where auction prices are significantly lower than in other regions. Consequently, comparing prices across auction types is more meaningful at the national rather than the global level.

In India, hybrid projects are generally more expensive than other types of renewable auctions. With an average awarded price of around USD 46/MWh, they cost nearly 17% more than solar PV plus storage projects. Compared to standalone onshore wind, hybrid auction prices are about 16% higher, and they surpass standalone solar PV auction prices by nearly 40%.

In countries implementing both standalone and firm-capacity auctions for solar PV, awarded prices for projects with storage were 33% higher than for PV-only auctions. The price differential between these two types of auctions varies significantly by country: India's solar PV and storage auctions awarded projects at around USD 39/MWh, almost 20% higher than standalone solar PV auctions. In Germany, the innovation auctions held between 2023 and 2025 resulted in an average price of USD 90/MWh – more than 50% higher. In Thailand, solar PV projects combined with storage were awarded at USD 83/MWh, around 30%

higher, while in Argentina they were around 16% higher at USD 82/MWh. Kazakhstan awarded a firm-capacity onshore wind project at a more than 50% higher price (USD 37/MWh) compared to wind-only projects.

Weighted average prices in firm vs non-firm auctions for utility-scale solar PV in India and Germany, 2021-2025



Note: Germany used fixed premiums in the 2021 and 2022 solar PV plus storage auctions, which means that bidders receive additional revenues from the electricity market.

Firm-capacity requirements are becoming a crucial auction design element with the first signs of international harmonisation

As firm-capacity auctions have gained traction, technical requirements have also become more important for auctioneers. For hybrid project auctions, these include: 1) the share of each technology in overall project capacity; 2) the location of each component; and 3) the minimum capacity factor.

In India, which is the only country with dedicated hybrid project auctions, the national guidelines suggest that each component should be at least 33% of the total contracted capacity. Regarding location, the solar and onshore wind components can be at the same or different locations. For the minimum annual capacity factor, in most auctions projects need to achieve 30%, although when combined with storage, this requirement can rise to 90%.

For auctions involving storage, the key design elements focus mostly on the battery component and include: 1) capacity; 2) location; and 3) operational requirements.

Most auction schemes require the storage capacity to be 20-30% of the installed capacity of the renewable energy plant. Almost all countries require storage of at least two hours, with only two countries requiring one hour, and one at least four hours. India does not impose a specific storage capacity but requires a minimum capacity utilisation factor of at least 80% or feed-in during specific peak hours.

Regarding location, almost all countries require that storage be co-located with the renewable power plant, i.e. sharing the same grid connection, which helps optimise available grid capacity. Only India and Hungary allow storage to be located anywhere in the country, independent of the renewable project's location.

Finally, auctioneers need to decide on the rules for operating the storage capacity. For instance, the facility can be limited to storing only electricity from the plant (and injecting it into the grid), or it can be allowed to exploit different business opportunities freely (ancillary services, etc.). In contrast with the aforementioned design elements, there is no overriding tendency, as countries are divided on this design element.

A closer look: Two-sided contracts for difference are set to become Europe's dominant support scheme

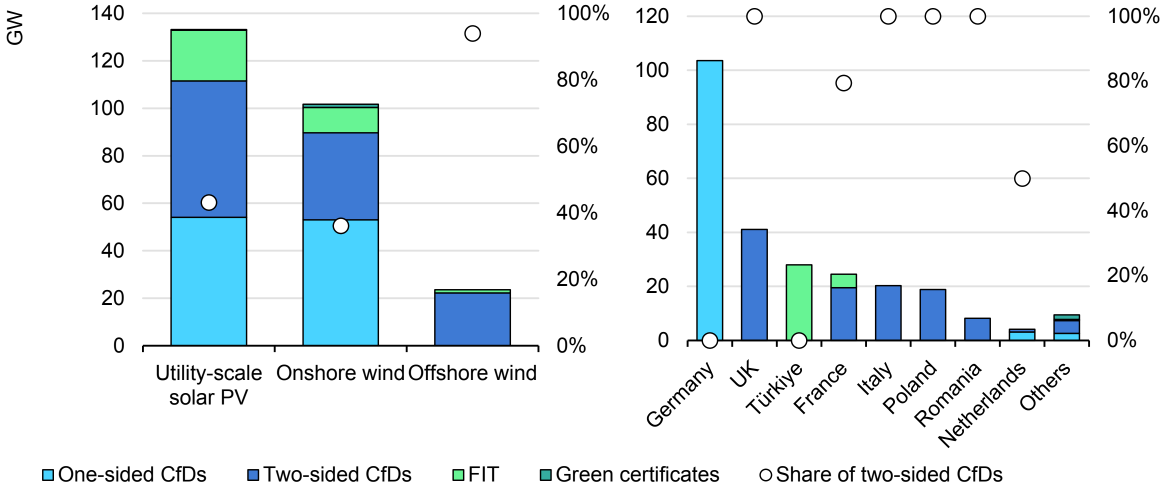
Two-sided CfDs are expected to trigger nearly half of Europe's policy-driven utility-scale solar PV and wind capacity additions through 2030

Two-sided CfDs have become a central policy instrument for renewable energy support in Europe, especially since the 2022-2023 energy crisis. Elevated electricity prices during this period triggered concerns over windfall profits for renewable electricity producers under existing support schemes. In response, governments across Europe have increasingly focused on implementing two-sided CfDs to protect consumers from excessive electricity costs, while stabilising investor returns.

Two-sided CfDs are arrangements that guarantee a fixed strike price to renewable electricity producers, with the government settling the difference between market revenues and the strike price. If market revenues fall below the strike price, the government pays the producer the shortfall, and if revenues exceed the strike price, the surplus is transferred to the government. This mechanism contrasts with one-sided CfDs, wherein producers retain any upside gains from higher market prices.

According to this year's forecast, around 45% of all policy-driven utility-scale solar PV and wind additions in Europe will be contracted through two-sided CfDs. This share is second after one-sided CfDs (mostly from Germany), which are expected to cover almost half of policy-driven additions.

Policy-driven utility-scale solar PV and wind capacity additions in Europe, by technology and contractual arrangement (left) and by country (right), 2025-2030



Notes: CfD = contract for difference. FIT = feed-in tariff. “Others” refers to Belgium, Hungary and Ukraine. Subsidy-free offshore wind auctions (e.g. for seabed leases) are excluded from this analysis.

Two-sided CfDs are prevalent in utility-scale solar PV and onshore wind additions, contributing roughly 35-40%. In offshore wind, two-sided CfDs stimulate nearly all capacity additions awarded under support schemes. While several projects from zero-subsidy auctions are expected to be built on a merchant basis, there is a recent trend towards to two-sided CfDs for offshore wind, with proposals discussed in Denmark and the Netherlands.

Based on our forecast, the United Kingdom remains the leading market for two-sided CfDs, accounting for over 35% of all capacity deployed in Europe under this scheme. France, Italy and Poland follow, each contributing around 17%. The remaining share is distributed across several countries, including the Netherlands, Croatia and Belgium. Some other countries, such as Romania and Czechia, have implemented two-sided CfDs in their recently introduced auction schemes.

National CfD designs reflect different approaches

By 2025, 19 European countries had either implemented or announced the use of two-sided CfDs. While the main mechanism remains consistent (i.e. providing revenue stability through an agreed strike price), governments continue to tailor key design elements to reflect national policy preferences and market conditions.

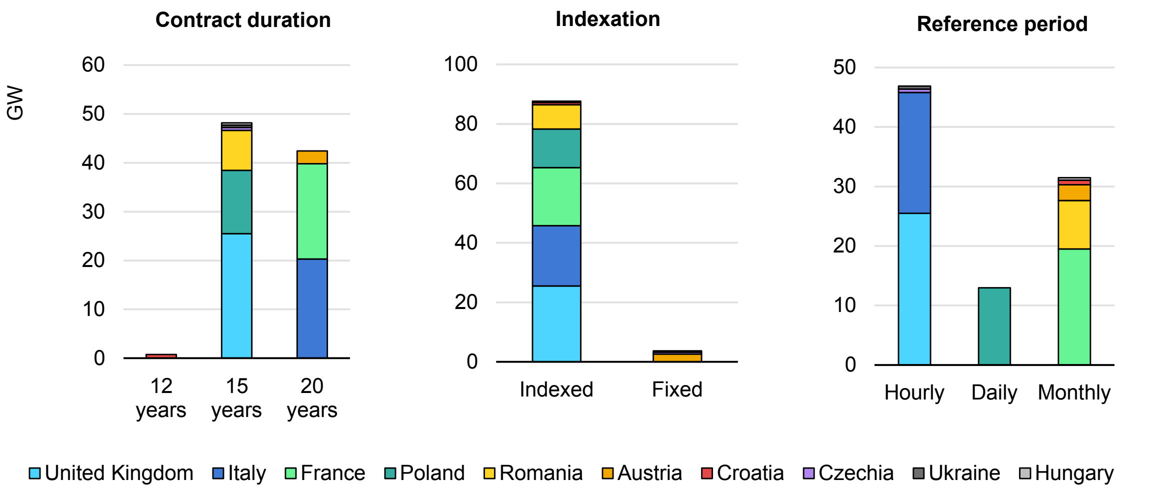
Overview of two-sided CfD designs by country

Country	Contract duration (years)	Indexation	Reference period	Reference market value
Austria	20	No	Monthly	Tech-specific
Albania	15	No	Hourly	n/a
Belgium	20 (offshore wind)	Yes (until financial close)	Monthly	Tech-specific
Croatia	12	Yes	Monthly	Tech-specific
Czechia	15	No	Hourly	n/a
Denmark	20	No (indexation under consideration)	Annual (monthly under consideration)	Simple average
France	20	Yes	Monthly	Tech-specific
Greece	20	No	Monthly	Tech-specific
Hungary	15	Yes	Monthly	Tech-specific
Ireland	16.5 (solar PV and onshore wind) 20 (offshore wind)	Yes (since 2023) (30% of the strike price, HICP, every year)	Hourly	n/a
Italy	20	Yes (at least partially)	Hourly	n/a
Lithuania	15 (offshore wind)	Yes (until permitting)	Hourly	n/a
Poland	15 (solar PV and onshore wind) 25 (offshore wind)	Yes	Daily	Simple average
Portugal	15	Yes (until commissioning)	Hourly	n/a
Romania	15	Yes (CPI, every 3 years)	Monthly	Tech-specific (only CfD units)
Serbia	15	Yes	Hourly	n/a
Spain	10-15 (12 years in recent auctions; exceptionally, up to 20 for high-CAPEX/high-risk technologies) 30 (offshore wind)	Yes	Hourly	n/a
Ukraine	15	No	Hourly	n/a
United Kingdom	15	Yes	Hourly	n/a

Notes: HICP = Harmonised Index of Consumer Prices. CPI = Consumer Price Index. In Austria, the requirement to transfer the surplus above the strike price to the government applies only to producers with projects larger than 20 MW (5 MW for solar PV).

One of the key design elements is contract duration. For solar PV and onshore wind, ten countries have adopted 15-year contracts, while six opted for 20 years. Only Croatia offers 12-year contracts, while Ireland chose 16.5 years. Spain has offered 12-year contracts in recent auctions, although contract duration is officially set for each auction round individually. Offshore wind projects tend to benefit from longer contract durations, with Ireland offering 20 years and Poland granting 25.

Utility-scale solar PV and onshore wind capacity additions through two-sided CfDs by design element in Europe, 2025-2030



Another key design element is strike price indexation, which protects against inflation by adjusting the strike price over time, typically linked to the national consumer price index. Indexed contracts provide greater revenue certainty, though they might increase government expenditures. Thirteen countries use indexed contracts, while six maintain a fixed strike price over the contract duration.

CfDs also vary in the reference period used to calculate the gap between market revenues and the strike price. A shorter period, such as hourly settlement, more accurately reflects actual market earnings and thus increases revenue certainty. At the same time, hourly periods tend to incentivise "produce-and-forget" behaviour. On the other hand, a longer reference period provides more incentives for market-friendly dispatch behaviour. Ten countries have adopted hourly reference periods, with another seven opting for monthly. Only Poland has implemented a daily reference period, and Denmark's is yearly.

In addition to these main design elements, several innovative types of CfDs are currently under consideration to address the potential inefficiencies of conventional contracts. One major weakness of the current production-based contracts is that the producer's dispatch decision might not be based solely on market price signals in all situations and could be distorted due to payments from the CfD system.

There is therefore ongoing discussion on decoupling payments from physical electricity delivery and basing them instead on a benchmark. One such approach under scrutiny is a financial CfD, which proposes a capacity payment linked to a payback obligation, both based on generation potential. Another proposal is the capability-based CfD, which links support to generation potential rather than actual dispatch. Both Belgium and Denmark have considered capability-based CfDs in their upcoming offshore wind tenders, shifting to more system-friendly renewable support.

Green certificates: The increasing international importance of energy attribute certificates

From domestic to international relevance

Energy attribute certificates (EACs) are tradable instruments that represent the environmental attributes of a unit of energy, most commonly renewable electricity. They are a key mechanism for tracking and verifying the renewable origin of electricity, and they enable accounting in both compliance frameworks and voluntary sustainability efforts. To substantiate claims of renewable energy consumption, EACs must be cancelled in a registry, ensuring that each certificate is counted only once and cannot be resold or reused.

Certificate schemes can be characterised as either voluntary or mandatory. In mandatory markets, governments require electricity suppliers or large consumers to source a minimum share of their electricity from renewables, often through a renewable portfolio standard (RPS) system or equivalent instrument. Obligated entities may meet these requirements by: 1) owning renewable energy assets; 2) procuring renewable electricity bundled with certificates; or 3) purchasing unbundled EACs on the market.

In voluntary markets, EACs enable consumers (for instance companies with sustainability targets) to reliably claim the use of renewable electricity and to reduce reported Scope 2 emissions. Large consumers typically buy and retire certificates themselves, while retailers perform this task for smaller customers.

In general, certificate prices in mandatory markets tend to be higher. Existing obligations, typically paired with penalties for non-compliance, drive demand for certificates. For instance, prices for Guarantees of Origin (GOs) in Europe have been fluctuating between EUR 1/MWh and EUR 10/MWh, whereas Renewable

Energy Certificates (RECs) in mandatory US markets have been priced at roughly USD 35/MWh, with voluntary certificates trading at around USD 3/MWh.

Overview of selected EAC schemes accepted by the RE100 initiative

Country/region	Scheme	Market type	Remark
Australia	Large-Scale Generation Certificates (LGCs), Guarantees of Origin (under development)	Mandatory/ voluntary	Under Renewable Energy Target (RET) scheme
Canada	Renewable Energy Certificates (RECs)	Voluntary/ provincial RPS	Depends on provincial frameworks
China	Green Electricity Certificates (GECs)	Mandatory (RPS)/ voluntary	
European Union	Guarantees of Origin (GOs)	Voluntary	Cross-border trade within EU
India	Renewable Energy Certificates (RECs)	Mandatory (RPOs)/ voluntary	Used for Renewable Purchase Obligation (RPO) compliance
Japan	Non-Fossil Certificates (NFCs), J-Credits (renewable), Green Electricity Certificates (GECs)	Voluntary	
Korea	Renewable Energy Certificates (RECs), Confirmation of Renewable Energy Use (CREU)	Mandatory (RPS)	
Philippines	Renewable Energy Certificates (RECs)	Mandatory	Under Renewable Portfolio Standard (RECs tradable on Renewable Energy Market [REM])
United Kingdom	Renewable Energy Guarantees of Origin (REGOs)	Voluntary	
United States	Renewable Energy Certificates (RECs)	Mandatory (state compliance)/ voluntary	Both voluntary markets and state RPS programmes
E.g. Brazil, South Africa, Viet Nam	International Renewable Energy Certificates (I-RECs)	Voluntary	Common where national scheme is lacking

Source: IEA analysis based on data from RE100.

Historically, EACs have been used primarily in domestic contexts, through schemes operating within national boundaries (e.g. China's Green Electricity Certificates) or within a region (e.g. GOs in the European Union). However, with cross-border multinational companies stepping up their sustainability efforts and emissions-based trade regulation on the rise, it has become critical for EACs to be accepted and recognised internationally.

Cross-border renewable electricity procurement is being hindered by non-acceptance of certificates

Despite growing demand, cross-border renewable electricity sourcing remains constrained by limited recognition of foreign EACs. Most national systems do not accept imported certificates for compliance or reporting, increasing challenges for corporate buyers.

Governments decide whether foreign-issued certificates are eligible for use within their national systems. In practice, most countries do not accept "foreign" EACs for domestic compliance or reporting purposes. This lack of mutual recognition restricts the development of international corporate PPAs.

However, some regions have achieved interoperability by harmonising their certification schemes. For example, the GO system in Europe enables certificate trading among participating countries, while the United States and Canada operate a compatible system of RECs. However, even within these frameworks, barriers remain. Certificates from non-EU countries, such as Serbia or Georgia, are typically not accepted within the European Union's GO scheme, limiting the participation of neighbouring countries.

Beyond national regulatory constraints, voluntary sustainability initiatives and industry associations also impose strict eligibility criteria. International programmes such as RE100 often reject the sourcing of EACs from foreign countries for their members, even when technically permitted under national schemes. For instance, for foreign certificates to be accepted, RE100 requires that 1) the regulatory framework governing the electricity sectors is consistent; 2) electricity grids are substantially interconnected; and 3) utilities/suppliers recognise each other's energy attributes and account for them. Thus, Icelandic GOs, for example, are tradable within the European system but are excluded from RE100 accounting. Similarly, companies in Singapore have limited options for procuring renewable electricity from neighbouring countries due to certificate non-acceptance.

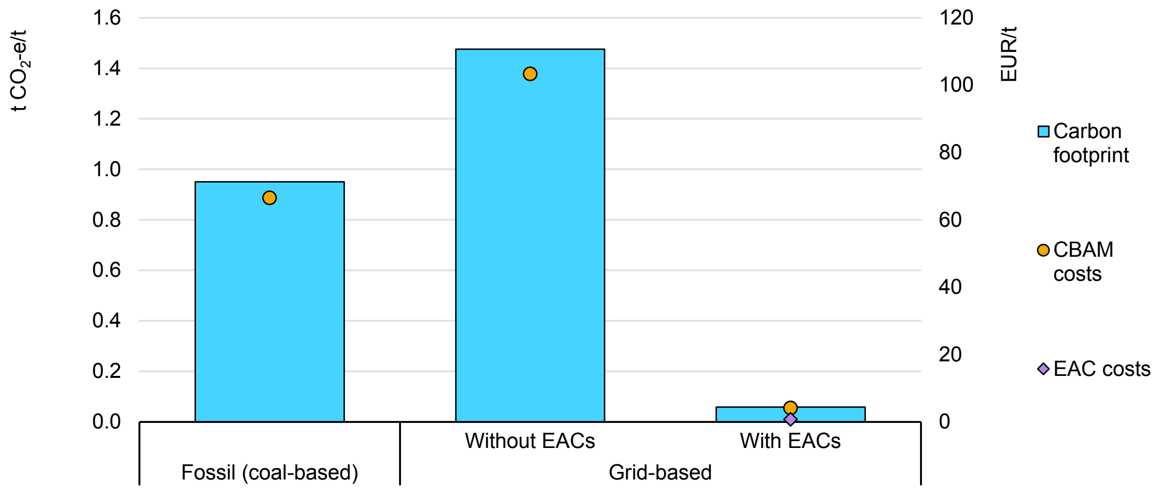
Governments are reluctant to accept EACs in emissions-based trade rules

While internationally recognised GHG accounting frameworks increasingly accommodate EAC use, national governments remain hesitant about accepting foreign certificates, particularly in regulatory and trade-related contexts.

The GHG Protocol, widely used by industry for corporate emissions reporting, defines two distinct approaches: location-based and market-based. The location-based method relies on the average emissions factor of the local electricity grid, while the market-based approach allows companies to report lower emissions by procuring EACs regardless of the grid's underlying emissions intensity.

Corporate initiatives and industry platforms, including RE100, have largely allowed the market-based approach. RE100 permits the use of most recognised EAC systems globally, enabling multinational companies to claim 100% renewable electricity sourcing. However, conditions may apply to avoid double counting or ensure environmental integrity. For example, since May 2025, companies in China have been required to purchase both green electricity certificates and carbon-offset certificates to meet RE100 requirements to avoid potential double counting.

Illustrative example of the impact of EACs on the carbon footprint of CAN fertilisers



Notes: EAC = energy attribute certificate. CBAM = Carbon Border Adjustment Mechanism. We assumed a grid emissions factor of 561 g CO_2-e/kWh, a price of EUR 70/t CO_2-e for a CBAM certificate and EUR 0.3/MWh for an EAC.

In contrast, national governments have shown greater reluctance to incorporate foreign-issued EACs into official GHG accounting methodologies, especially in sectors tied to trade-related regulations. This is particularly relevant in the context of emerging emissions-based trade rules and product-specific emissions standards, such as those under discussion in the EU Carbon Border Adjustment Mechanism (CBAM) or in the new Batteries Regulation.

Main differences between EU Guarantees of Origins and China's Green Electricity Certificates

Design element	Guarantees of Origin	Green Electricity Certificates	Comparison
Eligible technologies	Electricity, heating and cooling, and gas from renewable energy sources	Electricity from renewable energy sources; hydro only if connected after 2013	Slight difference in eligible technologies
Definition	1 GO = 1 MWh; fractions allowed since 2023	1 GEC = 1 MWh; no fractions allowed	EU moving to sub-hourly issuance
Validity	12 months for transactions, 18 months for cancellation	Up to 2 years (under discussion)	GECs have a (slightly) longer validity period
Interaction with RES support	Governments decide if GOs are issued if a plant receives support (or they auction these GOs themselves, retaining the revenues)	RES producers can receive both GECs and FIT-based support (GEC revenues are deducted from support payment)	Differences in support interaction
Trading	Multiple trades allowed before cancellation	Single trade only	Trading rules differ substantially
RES target achievement	Not linked to RES targets	Used for RPS compliance	GEC demand is driven by obligations in China
Measures against double claiming	Countries can be banned from exporting GOs; measures for electricity suppliers are under discussion	n/a	Stricter measures in the EU
Residual mix (electricity consumed without GOs)	Country- and EU-level residual mixes are calculated	n/a	Residual mix calculation is critical for GOs
Acceptance by industry	Accepted by RE100, but from 2024 observing a 15-year commissioning (or repowering) date limit + EU market segmentation based on specific requirements	Accepted by RE100 unconditionally after resolution of potential double counting	Both widely accepted

Notes: The information on "Interaction with RES support" for China refers to the situation for existing projects under the FIT scheme. Relevant policies on GECs for power plants with auctioned CfDs are still under discussion.

In such cases, carbon intensity is typically assessed based on the national electricity mix, and the use of domestic certificates is generally not permitted to adjust the calculated emissions footprint. The following illustrative example shows that calcium ammonium nitrate (CAN) fertiliser exporters from specific countries could reduce their potential CBAM expenditures by around 93-95% (including the EAC costs).

This hesitance in allowing the use of EACs stems in part from differences in certificate system designs. For example, China's green certificate framework differs from its European counterpart (GOs) in terms of validity, trading and residual mix.

As emissions-related climate policies expand, the lack of a harmonised approach to cross-border EAC recognition poses a growing challenge for both governments and multinational firms. Governments and policymakers should therefore continue discussions to define internationally accepted criteria that certificate schemes need to meet. This would stimulate international trade as well as cross-border renewable electricity exchanges.

Renewables and energy security

While renewable energy policies have generally focused on energy system decarbonisation and climate change mitigation, they are also paying increasing attention to energy security benefits. On one hand, expanding renewable energy use can help reduce dependence on imported fossil fuels and provide a stable price environment, sheltering countries from fossil fuel price volatility. Renewables also offer new opportunities for system resilience through decentralised generation, including rooftop solar PV.

On the other hand, however, integrating variable renewables such as wind and solar PV presents electricity security challenges and necessitates power infrastructure investments. Although using renewables reduces fossil fuel dependence, it creates new dependencies on international supply chains for both equipment and critical minerals. Consequently, the overall impact of renewables on energy security is complex and depends on policy priorities.

While this section dedicated to energy security covers several aspects of the situation, it does not aim to provide a comprehensive country-specific approach, as national policy priorities vary drastically. The four main topics we cover are: 1) how using renewables reduces fossil fuel imports; 2) solar PV and wind equipment manufacturing supply chain concentrations; 3) critical minerals supply dependency; and 4) the growing role of variable renewables in power systems and their integration challenges.

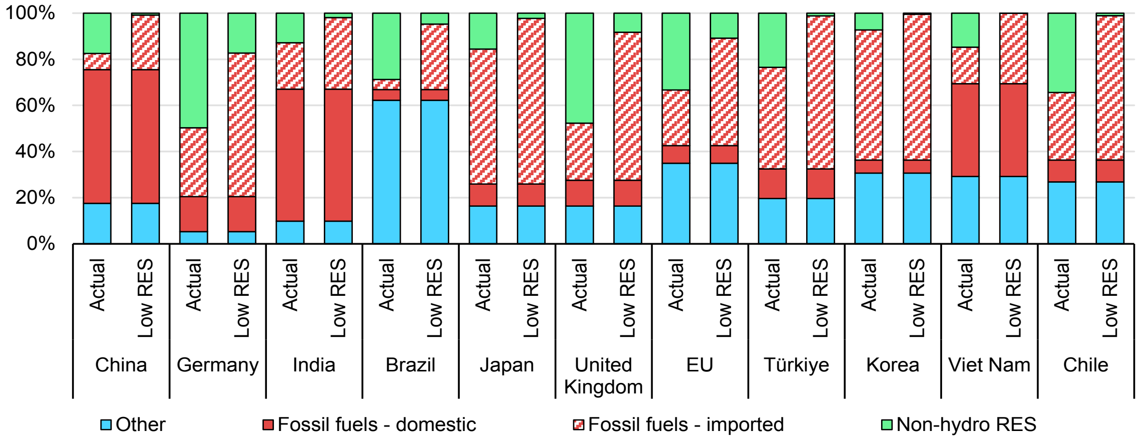
Fossil fuel import reductions

Renewables deployment has already significantly reduced fuel import needs and enhanced electricity supply security

Between 2010 and 2023, the world added around 2 500 GW of non-hydro renewable capacity, about 80% of which was installed in countries that rely on coal or natural gas imports for electricity generation. Fossil fuel importer countries often stand to gain the most from using renewables, both in terms of enhancing energy security and improving their economic resilience.

Renewable energy technologies inherently strengthen energy supply security, as they generate electricity without requiring continuous fuel inputs (excluding bioenergy). While critical equipment for renewable energy projects may be imported, the facilities can operate for years with limited external inputs – offering greater resilience during fossil fuel supply disruptions or price volatility.

Electricity generation fuel mix in selected countries, actual and in Low-RES scenario, 2023



Note: RES = renewable energy source.

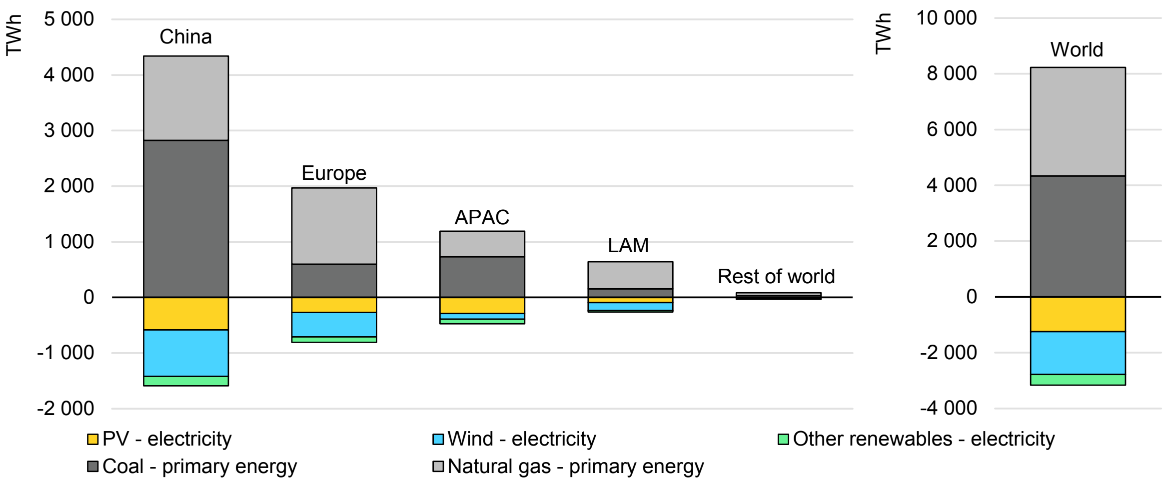
Fuel imports can represent a major cost for economies and government budgets. For instance, in 2022, amid the energy crisis triggered by Russia's invasion of Ukraine, EU importers spent close to USD 350 billion on coal and natural gas imports – triple what they spent in 2021 due to a spike in prices. An estimated one-third of that expenditure was linked to electricity generation. By displacing fossil fuel demand, renewables can help countries reduce the overall impact of such price shocks, enhancing both energy security and affordability for consumers.

Moreover, fossil fuel import expenditures offer limited benefits for domestic economies, as most of the spending flows abroad. In contrast, investments in renewables are infrastructure-intensive and can support local jobs, with a significant share of investments remaining within national borders, particularly where domestic supply chains are well developed.

To quantify the energy security benefits of renewable energy deployment in fuel-importing countries (excluding imports of oil and its products), we compared actual trends in capacity additions with electricity generation under a counterfactual scenario in which no new non-hydro renewable energy capacity was added after 2010 – called the Low-RES (renewable energy source) scenario.

In the Low-RES scenario, electricity that was actually generated from wind and solar would instead have been produced using coal and natural gas. The modelling assumes that hydropower, nuclear and other non-renewable generation remain unchanged, and that additional fossil fuel demand would be met through imports, given the limited scope for scaling up domestic production in most importing countries.

Differences in renewable electricity generation and fossil fuel imports, Low-RES scenario vs actual, 2023



Notes: APAC = Asia-Pacific. LAM = Latin America.

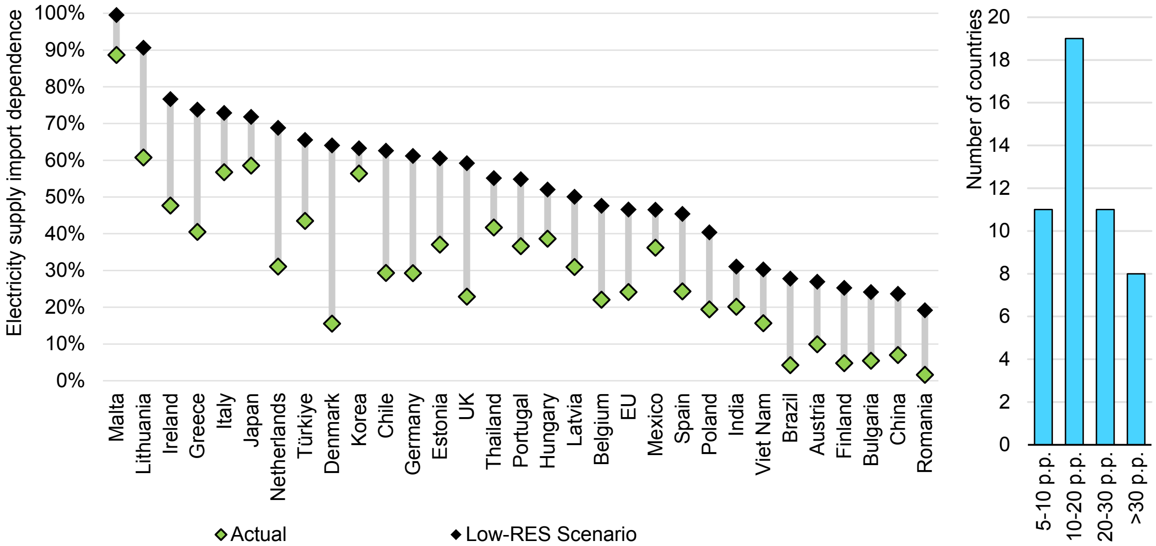
Renewables have helped countries reduce imports of coal by 700 million tonnes and natural gas by 400 billion cubic metres

From non-hydro renewable power generation capacity added between 2010 and 2023, approximately 3 200 TWh of electricity was generated in fuel-importing countries in 2023. Replacing this output with fossil fuels would require significantly higher energy inputs due to their lower conversion efficiencies. For example, typical coal and open-cycle gas turbine power plants operate at 30-40% efficiency, while combined-cycle gas turbines reach 50-60%. This means that each GWh of renewable electricity produced avoided the need for 2-3 GWh of fossil fuel inputs.

For instance, 1 GW of solar PV capacity in Europe generates roughly 1 000 GWh annually, equivalent to burning around 3 000 GWh of coal, or approximately 400 000 tonnes.

As a result, global imports of coal and gas in 2023 would have been around 45% higher – equivalent to over 8 000 TWh of additional fuel inputs – without non-hydro renewable energy developments since 2010. This means roughly 700 million tonnes of coal and 400 billion cubic metres of natural gas, together representing about 10% of total global consumption of these fuels in 2023.

Fossil fuel import dependence of electricity supply, actual and in Low-RES scenario, 2023 (left), and number of countries by difference in electricity supply import dependence between actual and Low-RES scenario, 2023

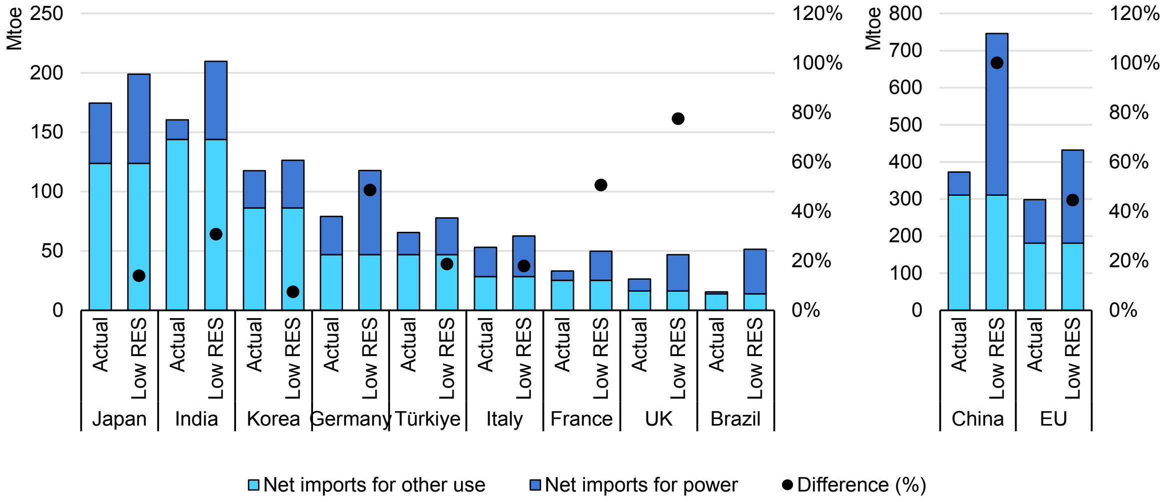


Notes: RES = renewable energy source. p.p. = percentage points.

The Low-RES scenario results in a substantial increase in reliance on imported fuels for electricity generation, significantly raising energy security risks in many countries. This impact is especially pronounced in countries with limited domestic energy resources, where renewables have played a key role in avoiding high import dependence. In the absence of renewable energy deployment, countries such as Germany, Italy, the Netherlands, the United Kingdom, Denmark, Türkiye, Chile, Thailand and Japan would have greater fossil fuel-based generation, increasing their vulnerability to supply disruptions.

In the European Union, limited domestic fossil fuel resources have long been the main driver behind renewable energy incentives. In 2023, about one-quarter of the EU electricity supply was met by imported fossil fuels. Without wind, solar PV and bioenergy deployment over the previous decade, this share would have reached nearly 50%. The impact is most striking for Denmark, the Netherlands, Germany and Greece, where the difference could have been as much as 30-50 percentage points. In the Low-RES scenario, the energy security challenges during the 2022 energy crisis would have been significantly more severe.

Net imports of coal and natural gas, actual and in Low-RES scenario, 2023



Notes: RES = renewable energy source. The difference in volume of net imports between the Low-RES scenario and actual in Brazil is equal to 230%.

The United Kingdom expanded its non-hydro renewable electricity generation nearly sixfold between 2010 and 2023. As a result, the share of its electricity supply met by imported fossil fuels decreased from around 45% in 2013 to less than 25% in 2023, despite declining domestic coal and gas output. In the Low-RES scenario, import dependence would have approached 60% by 2023.

In China, despite massive domestic coal production, imports made up about 10% of the country's total coal supply in 2023 – and nearly 40% of its natural gas. Without deployment of renewables over the past decade, China' s fossil fuel-based electricity generation would have been more than 25% higher. This would have potentially required a doubling of fossil fuel imports, raising China's electricity supply import dependence from 7% to nearly 25%.

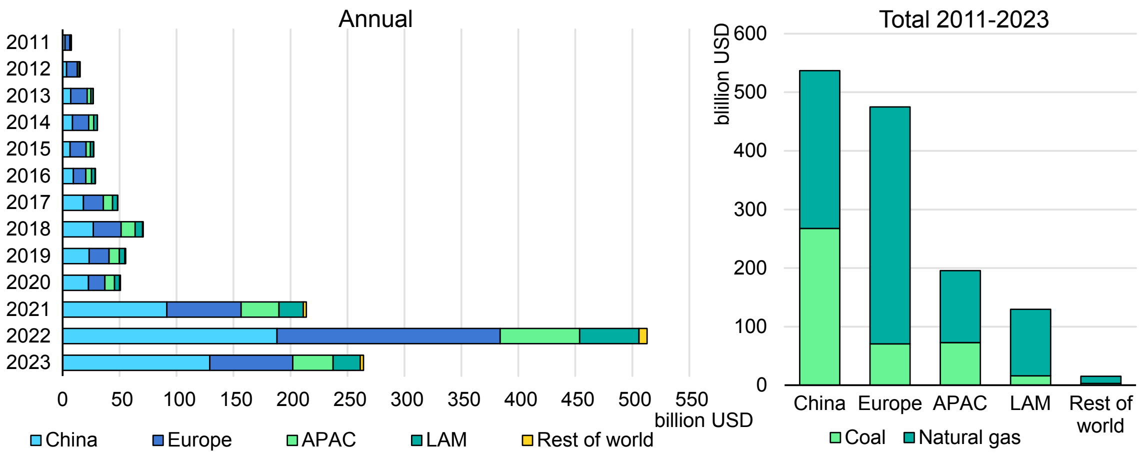
Brazil, with one of the lowest fossil fuel import dependencies among large economies – around 5% in 2023 – would also have experienced significant impacts. Without wind and solar energy deployment, fossil-based generation would have needed to rise by around 170 TWh, primarily from imported natural gas. Imports of natural gas would have increased nearly five-fold, pushing electricity import dependence to almost 30%, despite the country's large hydropower base.

Energy importers have reduced their fossil fuel bills by an estimated USD 1.3 trillion since 2010 owing to renewables

Overall, in the Low-RES scenario, fossil fuel import dependence for electricity generation would have increased for 19 countries – by more than 20 percentage points compared with actual 2023 levels. In fact, the difference would exceed 30 percentage points for eight of these countries.

Based on historic fossil fuel price trends, fuel-importing countries would have spent approximately USD 1.3 trillion more on coal and natural gas imports between 2010 and 2023 in the Low-RES scenario. China and Europe account for about 75% of the global cost difference over the analysis period, each theoretically avoiding around USD 500 billion in fossil fuel costs. For the rest of the world, the cost increase would have been almost USD 350 billion – concentrated in Brazil, India and Japan.

Annual and total differences in coal and natural gas net import costs for fuel-importing countries between actual and Low-RES scenario, 2011-2023



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Notes: RES = renewable energy source. APAC = Asia-Pacific. LAM = Latin America.
Source: IEA analysis based on data from Argus Direct (Argus Media group, all rights reserved).

Lower demand for fossil fuel imports proved particularly critical during the 2021-2023 global energy crisis, when war-related disruptions and market volatility pushed prices to historic highs. Without the deployment of non-hydro renewables, import expenditures in 2022 alone would have been over USD 500 billion higher – more than the GDP of many mid-sized economies – and the European Union's record coal and gas import bill in 2022 more than 40% larger.

Manufacturing and supply chain concentration

Solar PV

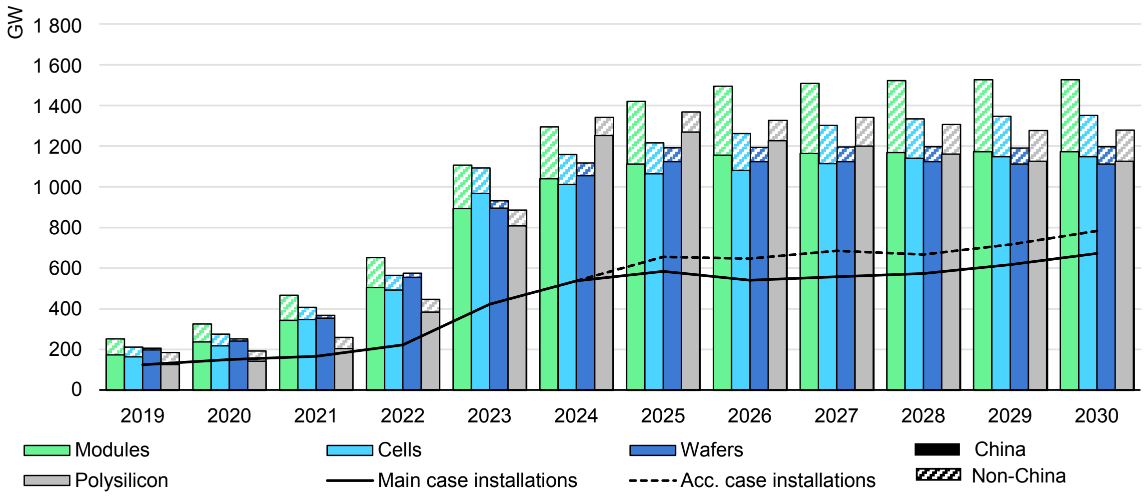
Overcapacity, record-low prices, trade barriers and regulatory shifts slow PV supply chain investments

In 2024, global solar PV manufacturing capacity expanded approximately 70 GW for cells, 190 GW for modules and wafers, and a record 460 GW for polysilicon. However, growth in all segments – except polysilicon – had decelerated relative to 2023, signalling a transition away from the rapid expansion phase of recent years. Between 2021 and 2024, overall potential PV supply chain output more than quadrupled, significantly outpacing the rate of PV installations.

Global PV module manufacturing capacity reached an estimated 1 100-1 350 GW in 2024 – more than double the annual deployment of PV systems. This substantial overcapacity has contributed to persistently low module prices, which are expected to trigger a slowdown in supply chain expansion from 2025 to 2030, particularly in China.

Over 2025-2030, total new manufacturing capacity is forecast to amount to only 230 GW for modules, 190 GW for cells and 80 GW for wafers, while polysilicon capacity decreases by 60 GW. Around 35% of new additions are expected to occur outside of China, compared with less than 10% over the last six-year period. Despite this shift, China is projected to maintain its dominant position in the global PV supply chain, with a 75-95% share of manufacturing capacity in 2030.

Solar PV manufacturing capacity and PV installations, 2019-2030



IEA. CC BY 4.0.

Sources: IEA analysis based on data from PV InfoLink, BNEF, S&P and SPV.

Of all PV manufacturing segments, wafer capacity is expected to be the lowest by 2030, at 1 200 GW. However, this is still 80% higher than projected deployment in the main scenario and 50% above the accelerated case, highlighting a continued imbalance between supply and actual demand.

While the current outlook is based on manufacturers' announced expansion plans, low profit margins due to intensified competition could result in project delays and cancellations, or in industry consolidation (see the section on financial health). These dynamics may lead to the closure of underperforming facilities and reduce overcapacity.

Excess capacity across the global PV supply chain has caused average utilisation rates of production facilities to decline, pushing manufacturers to increasingly compete for market shares through price reductions. In 2024, the estimated average utilisation factor – defined as production relative to nameplate capacity – fell to 55-65%, down from 60-80% in 2023. These manufacturing values exceed demand from actual PV installations, as trade and production data indicate significant inventory accumulation throughout the supply chain. The eventual drawdown of these inventories is expected to exert additional pressure on utilisation, potentially pushing it below 50% in the short term before a gradual rebound to 50-60% by 2030.

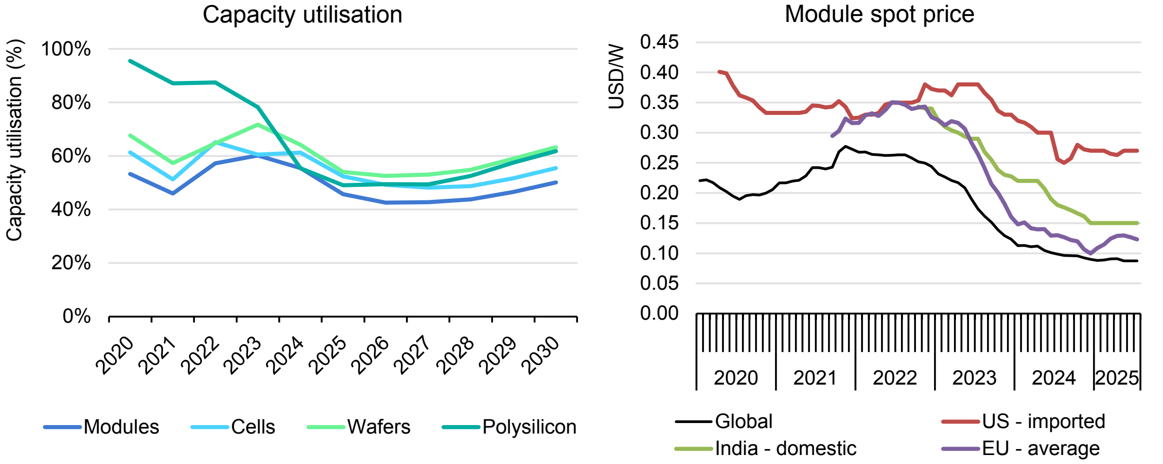
Continued growth in overcapacity has led to sharp drops in PV module prices, which reached new record lows in 2024. In fact, the average annual global wholesale spot price (excluding tariffs and non-market costs) declined nearly 45% year-on-year, falling to USD 0.09/W and stabilising at that level in H1 2025. This price is below the production cost for most manufacturers, including leading Chinese firms, and is widely considered unsustainable in the medium to long term. As a result, net profit margins of major PV manufacturers became negative in 2024, with further deterioration observed in H1 2025 (see the section on financial health).

However, actual PV module prices can vary drastically between countries. In markets with significant trade restrictions, they remain well above global averages. In the United States, for instance, high import tariffs and trade-related measures have resulted in elevated prices. As a result, the average spot price of modules shipped to the United States in H1 2025 reached USD 0.27/W, three times the global average.

Similarly, in India a combination of 40% basic customs duty on PV module imports and domestic content requirements for government-supported projects has driven up prices for locally manufactured modules. In H1 2025, the average spot price for domestically produced modules in India was USD 0.15/W, about 70% above the global average.

In contrast, European developers continued to have access to cheaper modules (around USD 0.12/W) in H1 2025 in the absence of import tariffs and major trade restrictions.

Estimated manufacturing capacity utilisation rates, 2020-2030, and average monthly solar PV module spot prices, 2020-2025



Sources: IEA analysis based on data from PV InfoLink, BNEF, S&P, pvXchange and SPV.

Solar PV manufacturing capacity outside of China expands despite headwinds, but supply chain concentration for key upstream production segments will remain above 90% in 2030

In 2023 and 2024, solar PV manufacturing capacity outside of China expanded at an accelerated pace, with significant investments in the United States, India and ASEAN.

In the United States, tax incentives under the Inflation Reduction Act (IRA) have been a key driver of solar PV supply chain investment. Between 2022 and 2024, this support contributed to an increase in module manufacturing capacity from 9 GW to 45 GW, and in polysilicon production from 21 GW to 33 GW.

However, recent policy changes introduced under the One Big Beautiful Bill, enacted in July 2025, have tightened eligibility criteria for incentives, impacting the investment outlook. The act introduces a 65% domestic-content requirement for stacking tax credits on integrated manufacturing activities (e.g. cells and modules), which must also be co-located within a single facility. In parallel, new FEOC restrictions prohibit the use of materials or components sourced from companies with significant ownership ties to China, Russia, Iran or North Korea, further narrowing the pool of eligible suppliers.

These new regulations led to a significant downward revision of planned investments, particularly in cell and wafer manufacturing. Compared with previous projections, expected capacity additions for cells have been halved from 30 GW to 15 GW, while wafer capacity growth has been reduced by two-thirds, from 15 GW to 5 GW. In contrast, around 30 GW of module capacity remains on track at advanced stages of development. Projects that began construction prior to the policy changes are expected to be commissioned in 2025 and 2026, but the outlook for additional project development remains highly uncertain.

In India, the Production Linked Incentive (PLI) scheme, basic customs duties and domestic-content requirements for government-supported projects are driving expansion. In 2023, India awarded PLI allocations for nearly 50 GW of cell and module capacity, 41 GW of wafer capacity, and 24 GW of polysilicon production. However, while targeted module capacity was achieved by the end of 2024, cell manufacturing reached only 20 GW and no wafer or polysilicon facilities had been commissioned. Delays resulted primarily from technical, financial and competitive challenges, particularly in upstream segments.

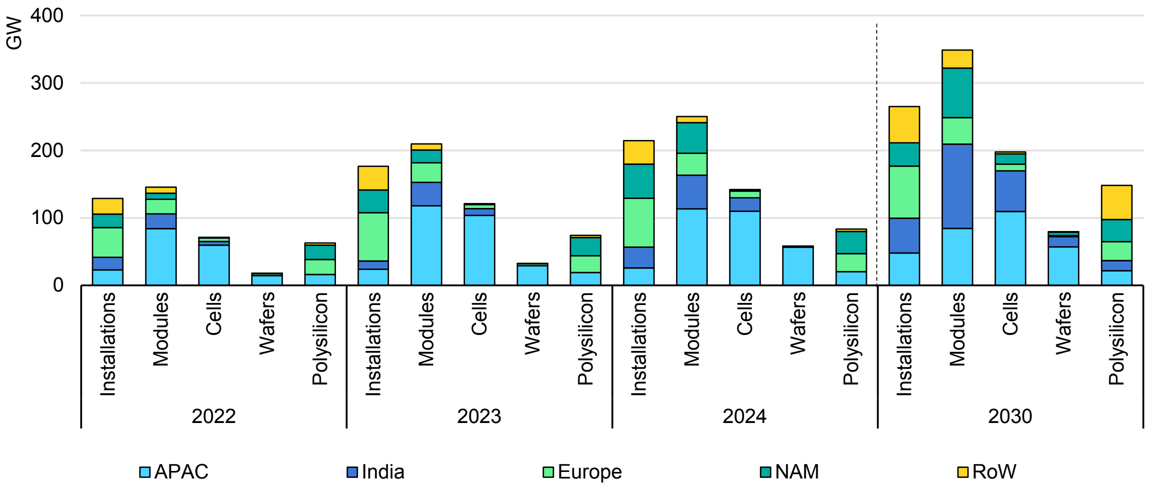
Consequently, India's manufacturing capacity estimates for 2030 have been revised downwards from last year's forecast – from 35 GW to 15 GW for wafers, and from 30 GW to 15 GW for polysilicon. In contrast, module manufacturing projections have been raised from 70 GW to 125 GW, driven by faster-than-expected capacity additions, strong domestic demand and rising exports, particularly to the United States. Despite ongoing delays, cell manufacturing is also expected to exceed previous forecasts, reaching 60 GW by 2030 (up from 50 GW) as domestic-content requirements are extended to this segment.

In ASEAN, the rapid expansion of manufacturing capacity across the PV supply chain has been stimulated mostly by direct investments from large Chinese manufacturers or their subsidiaries. Thus, this region was the largest PV production hub outside of China in 2024, with manufacturing capacity for 100 GW of modules (40% of global capacity excluding China), 100 GW of cells (70%), 50 GW of wafers (90%) and 15 GW of polysilicon (20%), located mostly in Viet Nam, Thailand, Malaysia and Indonesia.

These investments were primarily intended to geographically diversify solar PV manufacturing to serve markets with trade restrictions on Chinese imports, particularly the United States. However, the planned US imposition of new and significantly higher tariffs (circumvention, anti-dumping and countervailing duties) specifically targeting Viet Nam, Thailand, Cambodia and Malaysia, has led to a halt in investment activity and the expected closure of approximately 40 GW of module and 25 GW of cell production capacity in these countries. However, new capacity is under development in countries with lower proposed tariffs (e.g. Indonesia and Laos).

As of 2024, PV module manufacturing capacity outside of China exceeded installations by approximately 20%. However, other segments of the supply chain – particularly wafers – remain underdeveloped, leaving most module and cell producers dependent on imports from China for intermediate components. By 2030, non-Chinese module capacity is projected to exceed local deployment by over 30%, yet dependency on Chinese input materials is expected to remain largely unchanged.

Solar PV installations and manufacturing capacity outside of China, 2022-2030



Notes: APAC = Asia-Pacific. NAM = North America. RoW = rest of world.
Sources: IEA analysis based on data from PV InfoLink, BNEF, S&P and SPV.

In 2023 and 2024, the United States imported an estimated 55-60 GW of PV modules annually, with nearly one-third sourced from Viet Nam and about 20% each from Thailand and Malaysia. Other notable exporters included Cambodia and India.

In 2025, the US government concluded a trade investigation resulting in the decision to impose a combination of circumvention, countervailing and anti-dumping duties on key importing countries. These measures are expected to take effect in H2 2025. When combined with existing anti-dumping duties, the new universal global tariff and proposed reciprocal tariffs, the effective import tariff rates on modules and cells from Thailand, Viet Nam and Cambodia could reach 450-720%, and up to 90% for Malaysia.

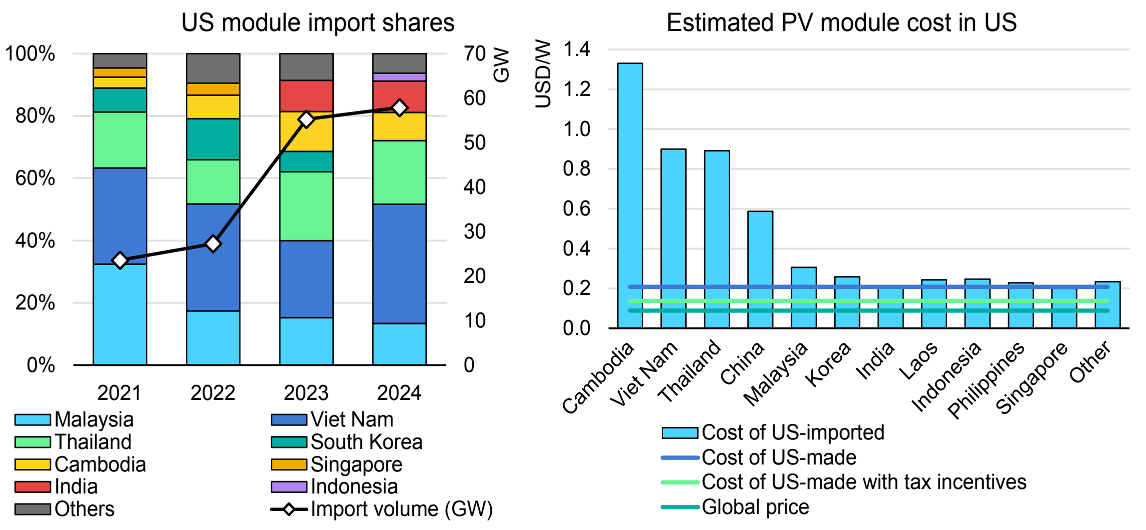
Given the existing nearly 400% effective tariff on module imports from China, these new measures could render approximately 90% of global PV module manufacturing capacity outside the United States non-competitive in the US market by 2026.

As a result, the theoretical pool of competitive PV module supply available to the United States in 2026 may be limited to approximately 70 GW of domestic capacity and around 180 GW of foreign supply, including up to 95 GW from India. However, this potential is likely to be further constrained by FEOC restrictions. Notably, around one-third of expected US module manufacturing capacity is being developed by companies with full or partial Chinese ownership, potentially rendering their products ineligible for federal incentives.

In addition, FEOC rules concerning the origin of module components may disqualify products from several non-Chinese manufacturers that rely on Chinese-made cells or wafers. Based on the current project pipeline, only around 3 GW of fully integrated domestic silicon PV manufacturing capacity is expected to be operational in the United States by 2030.

The supply landscape for PV modules and components in the United States remains highly dynamic as manufacturers adapt to evolving trade and FEOC regulations. This is already reflected in efforts to relocate production from high- to low-tariff countries in the ASEAN region. The impact of these dynamics on PV system prices in the US market remains highly uncertain.

Solar PV module US import shares, 2021-2024, and estimated average cost of modules imported by the United States after announced tariffs



Sources: IEA analysis based on data from PV InfoLink, BNEF, S&P and SPV.

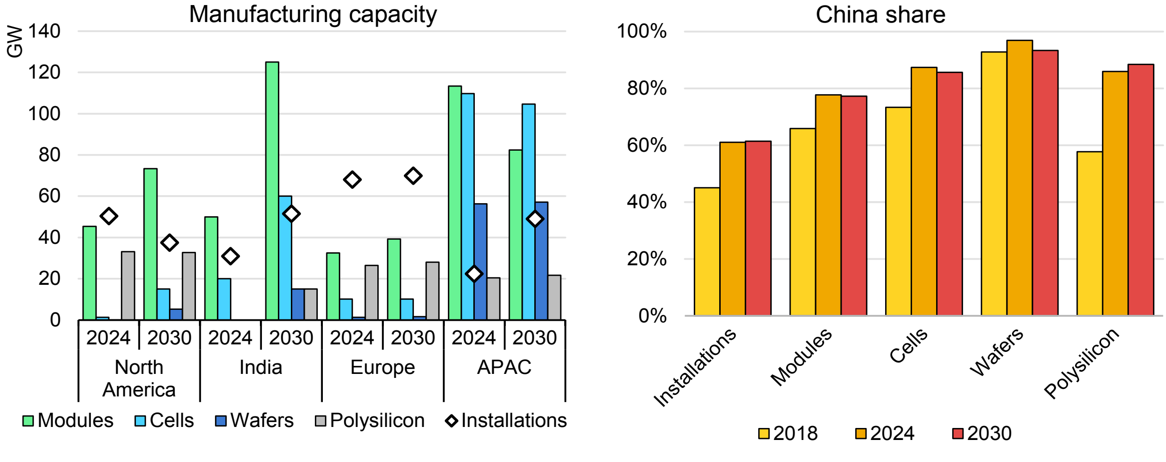
In 2024 (outside of China), complete crystalline silicon PV supply chains – encompassing polysilicon to modules but excluding auxiliary components such as frames, encapsulation materials and glass – existed only in Japan (with an estimated 1 GW of throughput capacity) and Malaysia (7 GW). By 2030, this list is expected to also include India (15 GW) and the United States (5 GW). In all these cases, limited wafer manufacturing capacity remains the main bottleneck.

Except for Malaysia, domestic supply chains in these countries are anticipated to cover only a fraction of their 2030 deployment needs – approximately 13% in Japan, 14% in the United States, and just under 30% in India. As a result, the only countries expected to achieve full self-sufficiency for all the main stages of crystalline silicon PV manufacturing by 2030 are China and Malaysia.

At the regional level, North America's self-sufficiency remained at zero in 2024, due to the absence of wafer production and minimal cell manufacturing capacity. While some progress is expected by 2030, slower-than-anticipated wafer investments limit the region's integrated domestic supply potential.

Despite the introduction of multiple policy initiatives since 2023, European solar PV manufacturing investments remain limited in the absence of stronger trade measures. As a result, capacity growth between 2024 and 2030 is expected to be marginal and concentrated in module assembly, while supply chain capacity in other segments will remain well below regional demand.

Regional solar PV manufacturing capacity and installations, 2024-2030, and China's share in global PV manufacturing capacity, 2018-2030



Note: APAC = Asia-Pacific.
Sources: IEA analysis based on data from PV InfoLink, BNEF, S&P and SPV.

In the Asia Pacific region (excluding China and India), strong module demand growth is projected to outpace regional polysilicon production capacity, reducing theoretical self-sufficiency from around 80% in 2024 to 45% by 2030. Nonetheless, module and cell capacity in the region is expected to remain sufficient to meet deployment needs.

In India, rapid expansion of module manufacturing between 2024 and 2030 is expected to create significant overcapacity in this segment. However, limited progress in wafer and polysilicon manufacturing is likely to constrain upstream integration, resulting in an overall domestic self-sufficiency rate of approximately 30% by 2030.

Despite a projected slowdown in PV manufacturing investment and planned capacity retirements, China's large existing production base is expected to retain its dominant position in the global PV supply chain through 2030. Market shares are anticipated to remain broadly stable, at 75% for modules, 85% for cells, 90% for polysilicon and 95% for wafers.

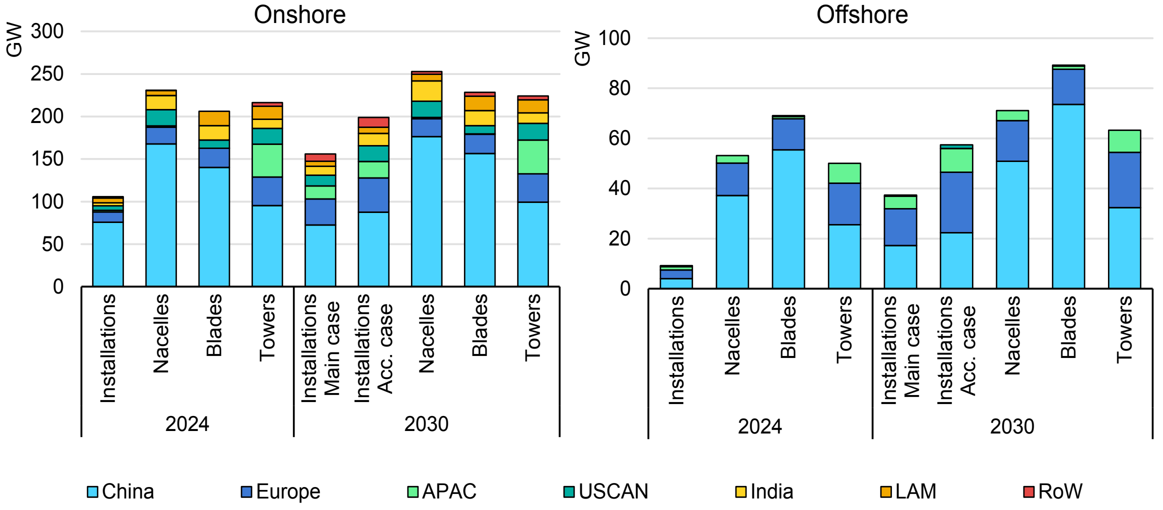
Wind

China's original equipment manufacturers accelerate expansion into emerging markets amid overcapacity and slowing deployment at home

In 2024, global manufacturing capacity for key wind turbine components – nacelles, blades and towers – reached 210-230 GW for onshore wind and 50-70 GW for offshore wind. For onshore wind, this is twice the actual gross installations of 2024, indicating significant overcapacity. The oversupply situation is even more pronounced in the offshore segment, in which capacity for the most limited part of the supply chain – towers – was up to four times higher than annual installations.

Only limited investments in new factories for onshore wind turbines have been announced, with total manufacturing capacity expected to increase only 10%, reaching 220-250 GW. For offshore wind, planned expansion is larger, with 25% growth raising overall supply chain production capability to 65-90 GW.

Wind manufacturing capacity and gross installations, 2024 and 2030



Notes: APAC = Asia-Pacific. USCAN = United States and Canada. LAM = Latin America. RoW = rest of world.
Sources: IEA analysis based on data from S&P and BNEF.

Assuming no additional investments, existing manufacturing capacity and projects under development are expected to be sufficient to meet global wind turbine demand through 2030. In the main case forecast, global manufacturing capacity exceeds projected onshore deployment by around 45% and offshore by 70%. However, to meet the requirements of the accelerated case, additional investment in key supply chain segments may be needed.

China remains the dominant global manufacturing hub for both onshore and offshore wind turbines, reflecting its position as the world's largest demand centre for wind. The country accounts for an estimated 70-80% of global blade manufacturing, 45-50% of tower production and around 70% of nacelle assembly capacity. Outside of China, significant manufacturing capacity is concentrated in the European Union, the United States, India and Brazil, with notable tower production facilities also located in Viet Nam, Korea and Türkiye.

However, headline global capacity figures do not fully reflect effective supply availability. Wind turbines are not widely interchangeable commodities – unlike solar PV modules – due to variations in turbine models, site-specific design requirements, and different national regulations. Wind farms are typically designed around a specific turbine model, often custom-built or modified to meet local conditions, such as low wind speeds, noise restrictions or limits on turbine size. This means capacity to produce one turbine model may not be easily repurposed to meet demand elsewhere.

In addition, many plants, particularly in China, are configured to manufacture older, smaller turbine models that are no longer in demand since the country shifted wind development from the eastern coastal provinces to large-scale projects in the northern and western interior. Such plants may therefore need retooling to remain competitive or may be decommissioned, creating uncertainty about how much nominal global capacity will remain usable.

Logistical and regulatory barriers also impede cross-border trading of large wind turbine components. The main turbine components are large and costly to transport, making proximity to deployment sites critical. Plus, certification requirements can prevent foreign turbine models from entering certain markets (for instance, turbines commonly deployed in China may not meet European technical standards). Trade measures and industrial policies can further limit equipment flows, as in the United States, where domestic-content rules tied to tax incentives restrict the use of foreign-manufactured components.

As a result, much of the apparent global manufacturing overcapacity, especially in China, may not be easily leveraged to meet demand in other regions. While manufacturers can adapt sourcing strategies and project configurations to some degree, the global supply situation remains highly fragmented and dependent on evolving market conditions and policy frameworks.

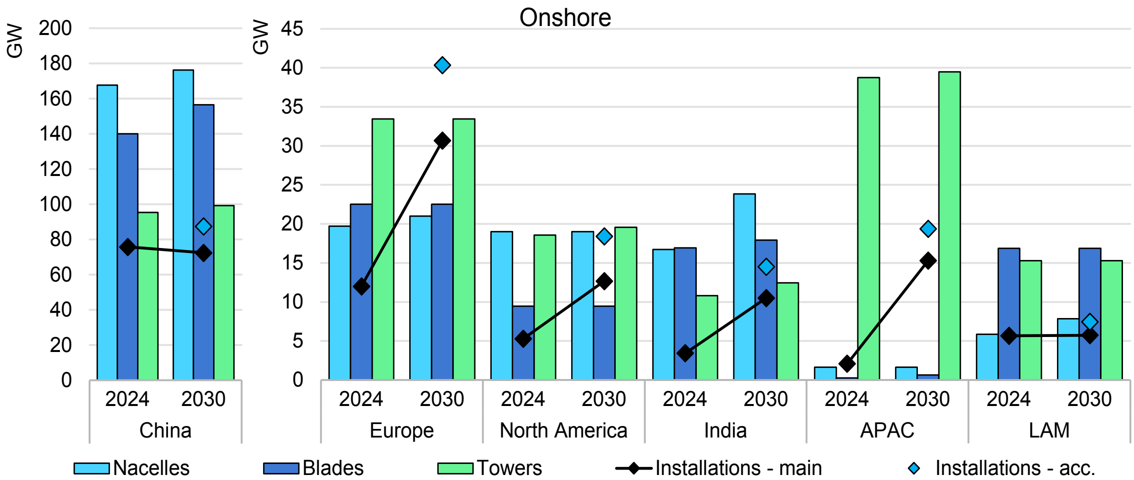
Onshore wind manufacturing supply chains remain diverse

In China, onshore wind manufacturers expanded their production capacity significantly in anticipation of a deployment surge between 2023 and 2025, when annual installations were expected to reach 70-80 GW. This investment wave led to substantial overcapacity, particularly in the blade and nacelle segments, for which manufacturing capacity doubled actual installations. The resulting oversupply has intensified competition, contributing to record-low turbine prices.

Overcapacity is expected to persist through 2030, especially as annual installations begin to slow. A widening supply-demand gap over the forecast period could lead to market consolidation and the potential closure of less competitive plants, particularly those configured to manufacture outdated turbine models no longer aligned with current project requirements.

In Europe, the current manufacturing base is sufficient to meet present demand. However, the planned acceleration of gross deployment to around 25 GW in 2026 could strain supply chains, particularly for blade production and nacelle assembly. While new investments will be needed to meet future demand, original equipment manufacturers (OEMs) remain cautious amid concerns over competition from imports, overcapacity risks and persistent low profitability.

Onshore wind manufacturing capacity and gross installations by region, 2024 and 2030



Notes: APAC = Asia-Pacific. LAM = Latin America.
Sources: IEA analysis based on data from S&P and BNEF.

In the United States, new restrictions on eligibility for tax incentives – for both turbine manufacturers and project developers – have led to a pause in expansion plans. While current manufacturing capacity is adequate for near-term demand, meeting the expected peak of 14 GW in 2027 might require increased imports, particularly of blades. Post-2027, demand is expected to decline below nacelle assembly and tower production capacity.

India continues to play an important role in global wind manufacturing, with contributions from domestic firms, Western OEMs and, more recently, Chinese manufacturers. Since 2023, the share of Western OEMs in the domestic market has declined sharply – from over 50% on average between 2018 and 2022 to below 5% – as their focus shifted to core US and European markets. This has left several gigawatts of manufacturing capacity underutilised and oriented towards exports. At the same time, Indian and Chinese manufacturers are planning expansions. Looking ahead, India is expected to remain an export hub for onshore wind components through 2030.

In Asia Pacific, deployment is expected to outpace available manufacturing capacity due to a lack of planned investments. Viet Nam and Korea continue to be leading global exporters of wind towers in 2030, but without further investment, their capacity to produce other turbine components will be limited, meaning most of these parts will have to be imported.

In Latin America, current manufacturing capacity is projected to meet regional demand, particularly given the stabilisation of deployment. The region is expected to maintain around 10 GW of blade and tower production capacity for potential exports.

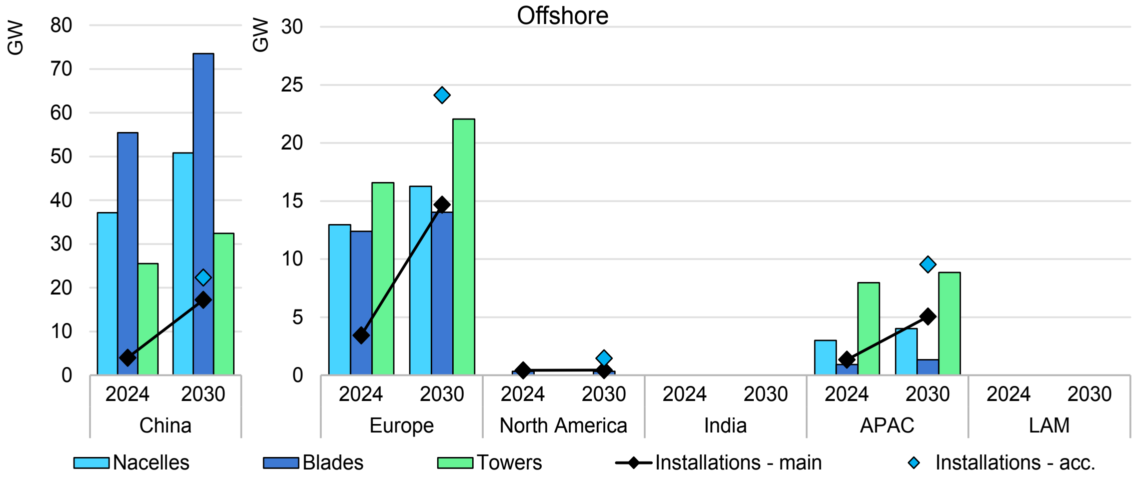
Although the offshore wind supply chain is diverse and well supplied, regional and component-specific bottlenecks could emerge by 2030

In China, a surge in offshore wind investments in 2021 triggered rapid expansion of the domestic supply chain, with further growth expected through 2030 in anticipation of sustained market acceleration. As a result, manufacturing capacity in the offshore segment exceeded annual installations by a factor of 6 to 14 in 2024, depending on the component. With deployment unlikely to rebound significantly before 2028, this overcapacity is placing considerable pressure on manufacturer profitability.

Consequently, Chinese companies are increasingly targeting export markets. However, penetrating international markets has proven challenging. By 2024, less than 500 MW of offshore wind turbines from Chinese manufacturers had been installed outside of China.

In Europe, offshore wind manufacturing capacity remains underutilised, with 2024 production potential exceeding annual installations by a factor of three to five. This imbalance continues to weigh on OEM profitability. However, a significant acceleration in offshore wind deployment is anticipated towards 2030, potentially tightening supply chains. New investments are under way in growing markets such as Poland and the United Kingdom, though many companies remain hesitant to commit additional capital, awaiting clearer policy direction and visibility on long-term project pipelines across the European Union.

Offshore wind manufacturing capacity and gross installations by region, 2024 and 2030



Notes: APAC = Asia-Pacific. LAM = Latin America.
Sources: IEA analysis based on data from S&P and BNEF.

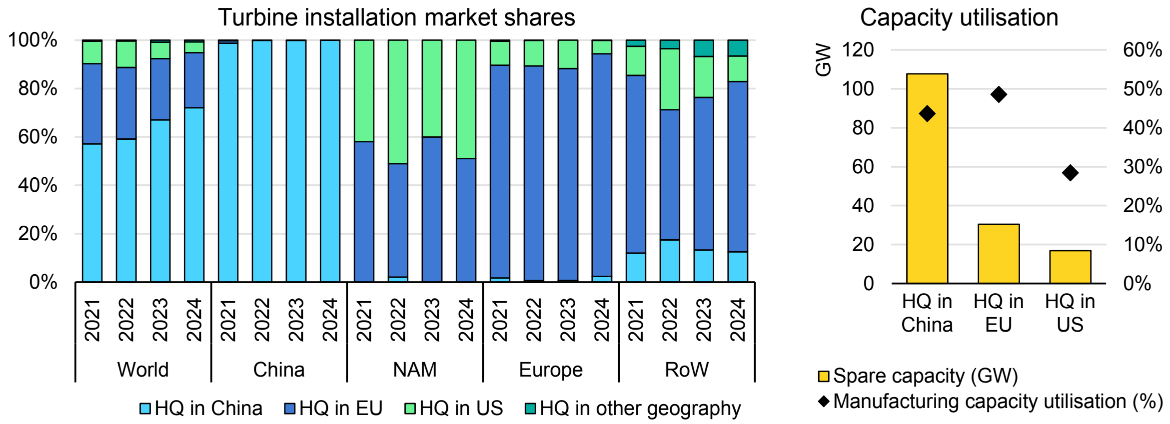
In the United States, the shift in federal policy regarding offshore wind development has resulted in the cancellation of a majority of planned deployment projects and the suspension of associated manufacturing expansion plans.

In the Asia-Pacific region, expanding nacelle assembly capacity supports offshore wind deployment plans in Japan, Korea, Viet Nam and Chinese Taipei. Production at Viet Nam's large tower manufacturing base, primarily focused on exports, is expected to exceed regional demand by 2030. However, blade manufacturing capacity remains insufficient, potentially creating bottlenecks if further investment is not forthcoming.

OEM competition in emerging markets

In 2024, the global wind turbine market remained highly fragmented, with distinct regional supply patterns. China sourced its supplies almost entirely from manufacturers with domestic headquarters, while installations in North America and Europe were dominated by regional OEMs. In the rest of the world – a market of approximately 14 GW – European and US OEMs maintained a strong presence with an estimated 80% market share. Chinese manufacturers accounted for nearly 15%, underscoring the persistent obstacles they face in expanding beyond their domestic market, including regulatory challenges, compliance rules and a limited international track record.

Wind turbine market shares by original equipment manufacturer headquarters, 2021-2024, and spare manufacturing capacity



Notes: NAM = North America. RoW = rest of world.
Sources: IEA Analysis based on data from S&P and BNEF.

However, the position of Chinese OEMs in markets outside the European Union and the United States is evolving rapidly. Their share of turbine delivery contracts in these markets has risen significantly – from less than 10% in 2021 to over 40% in 2023 and nearly 50% in 2024 – indicating a likely increase in their installed market share in upcoming years. For the first time, large-scale supply contracts have been awarded to Chinese manufacturers in countries such as Brazil, Argentina, Australia, Chile, Egypt, Georgia, India, Laos, Morocco, the Philippines, Saudi Arabia, South Africa, Korea, Türkiye and Uzbekistan.

This expansion is expected to accelerate, as the combined size of these markets is set to triple by 2030, surpassing 40 GW of annual wind deployment. Chinese manufacturers are well positioned to meet this demand, benefiting from large-scale vertically integrated manufacturing capacity that helps insulate them from logistical bottlenecks and material cost fluctuations. In many of these markets, particularly those closer to China such as Southeast and Central Asia, Chinese turbines are offered at a 20-40% discount compared with those of Western OEMs, largely owing to lower transportation and production costs.

Chinese OEMs are increasingly looking abroad to offset domestic overcapacity and declining margins amid intensified competition at home. In contrast, Western OEMs have scaled back activity in non-core markets to focus on restoring profitability following several years of negative margins (see the financial health section).

Critical materials for solar PV and wind

Rapid solar PV and wind deployment growth has boosted demand for critical materials significantly, raising concerns about whether supplies can keep pace in the context of long lead times and high costs for new mining and refining capacity. Supply concentrations further heighten security risks. Although supplies of many minerals are currently more than adequate, rapidly growing demand and heavy reliance on a small number of suppliers mean that supply chains remain highly vulnerable to disruption.

Solar PV: Copper, silicon and silver

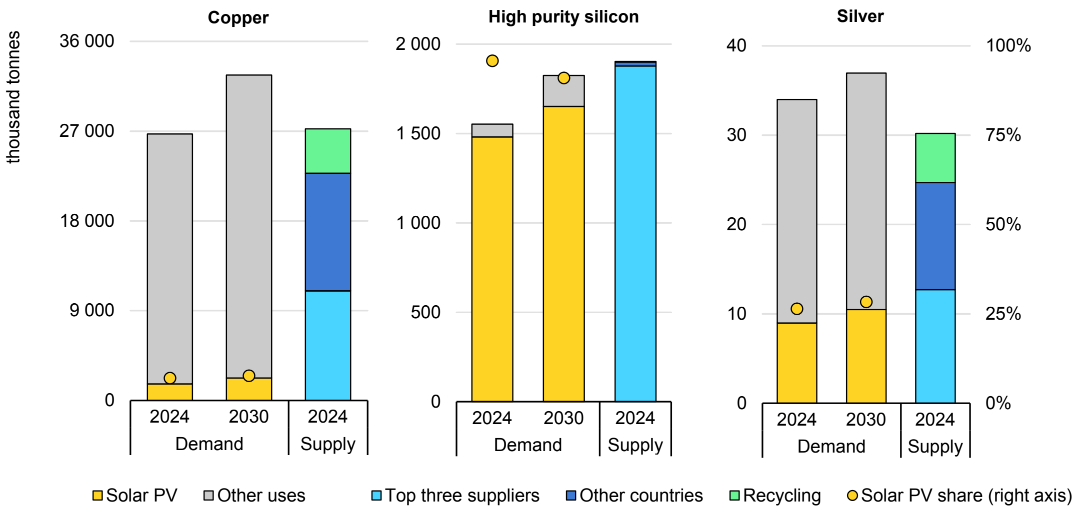
Clean energy technologies account for around 30% of global copper demand. While the major consumers remain grids, solar PV equipment manufacturing uses around 6% of global copper production today. By 2030, however, global copper demand for solar PV could increase by 35%. Nevertheless, the share of solar PV in overall global copper demand is expected to remain basically unchanged.

Three countries dominate global copper mining today – Chile, the Democratic Republic of Congo (DRC) and Peru – while the refining leaders are China (with a market share of around 45%), followed by the DRC and Chile. Copper refining is highly concentrated, and diversification prospects are limited, with China leading in primary supply. While recycled copper meets 16% of the copper supply and helps support diversification, market uncertainty stemming from high supply concentrations remains a risk for clean energy technologies in general and for solar PV in particular.

The deployment of clean energy technologies, particularly solar PV, has driven a rapid increase in silicon consumption. Since 2023, global silicon demand for solar PV manufacturing has grown by 33% and is projected to rise another 12% by 2030. High-purity silicon (6N), of which solar PV consumes 95%, represents nearly one-third of total silicon production.

China dominates both mining (80%) and refining (95%), making the supply highly concentrated and vulnerable to disruption. Although new projects are under way in Malaysia and Oman, diversification remains limited due to high costs and long development times. Recycling provides only a niche share because of high costs and lower-purity output (5N), prompting research into alternatives such as perovskites and organic photovoltaics, which have yet to be manufactured at full commercial scale.

Key mineral demand (2024 and 2030) and supply (2024), and solar PV shares in total global demand



IEA. CC BY 4.0.

Note: Copper supply includes refined output from primary materials and secondary copper scrap.
Sources: IEA (2025), Global Critical Minerals Outlook; and USGS (2025), Mineral Commodity Summaries 2025.

The solar PV industry has also become a major driver of global silver demand, with its use tripling since 2015 and forecast to increase another 17% by 2030. In 2024, solar PV accounted for almost 20% of all silver consumption. However, the supply of high-purity silver is tightening: global mining output has fallen 7% since 2018, and prices are rising. Over half of the world's silver supply comes from just three countries: Mexico, China and Peru, making the market highly concentrated.

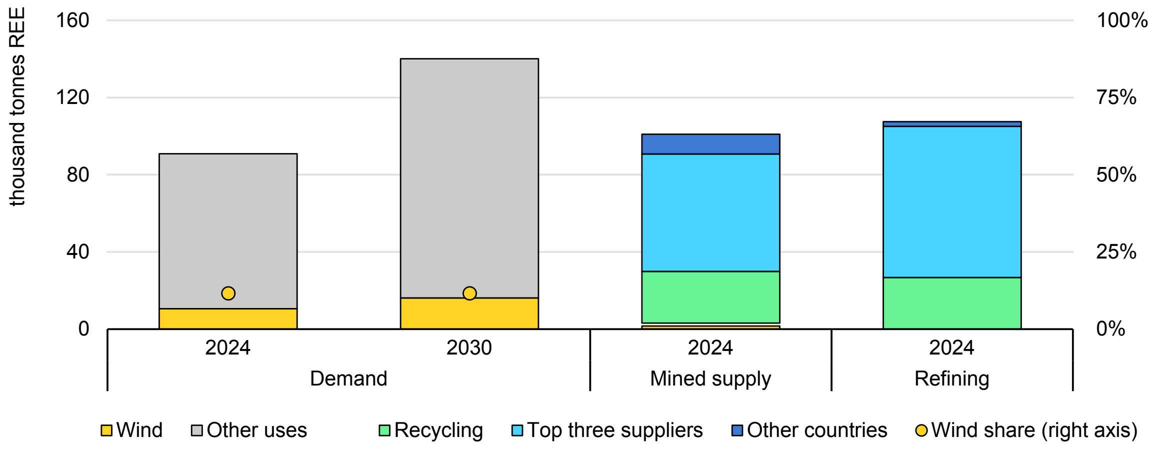
Most silver is produced as a co-product of other metals and rising prices may not necessarily translate into timely increases in new supply. Recycling meets about 20% of from demand but is restricted by purity requirements and the long lifespan of solar panels. Supply risks for PV manufacturing are therefore increasing, and while efforts are under way in Australia, Germany and France to replace or cut silver use by up to 91%, the substitutes are not yet commercially available.

Wind turbines: Rare earth elements

Rare earth elements (REEs), primarily neodymium, praseodymium, dysprosium and terbium, are key for magnets used in offshore and larger onshore wind turbines for their efficiency, while most onshore turbines use geared electromagnetic drivetrains with limited use of REEs. Since 2015, demand for REE magnets has nearly doubled and is set to increase 53% by 2030. Wind turbine manufacturing consumes around 10% of the world's total REE supply.

The supply is highly concentrated: China controls mining (60%), refining (~90%) and NdFeB (neodymium-iron-boron) magnet production (90%). It has the world's largest REE deposits and has enacted policies to develop a strong downstream industry.

Rare earth element demand (2024 and 2030) and supply (2024) for wind turbines, and wind demand shares in total REE demand



Notes: REE = rare earth element. The figures refer to values for magnet rare-earth elements.
Sources: IEA (2025), Critical Minerals Data Explorer (accessed 30 September 2025); and USGS (2025), Mineral Commodity Summaries 2025.

Efforts are therefore growing globally to diversify the supply, including mining projects in Australia, the United States and Brazil, and planned processing plants in the United States, Estonia, Malaysia and France. Despite these prospects, however, mining and especially refining are expected to remain highly concentrated in China.

Recycling remains limited, providing under 1% of supply (when manufacturing scrap is excluded), but is gaining traction globally owing to export restrictions and rapidly growing demand. Emerging alternatives, such as iron nitride and other REE-free magnet designs in the European Union and the United States, aim to reduce or eliminate the need for REEs but are not yet commercially available.

Policies to increase diversification are driving domestic mining, refining and recycling of key minerals for solar and wind energy

Governments are devoting greater policy attention and support to domestic production, recycling capacities and research into alternatives to diversify critical mineral supply sources and reduce supply risks. These measures are crucial, but the long lead times and high costs mean it may take time to have a material impact.

Countries are aiming to boost domestic production and recycling by introducing funding mechanisms as well as investments. In the European Union, France's ROSI is already a major recycling plant, but ReProSolar, Photorama and Icarus are also piloting industrial-scale recycling. EIT RawMaterials co-ordinates REEs recycling in the European Union, focusing on advancing recycling technologies, collection systems and traceability.

Recent policy developments for critical minerals

Country	Policy
China	The revised Mineral Resources Law (November 2024), in effect from July 2025, aims to increase strategic mineral reserves and boost domestic production capacity.
China	Export restrictions (April 2025) were introduced for REEs and permanent magnets.
China	The 14th Five-Year Plan and accompanying guidelines aim to establish the solar PV recycling industry by 2025, restrict scrap exports, tighten environmental standards and encourage technological innovation.
Canada	The Critical Minerals Infrastructure Fund (CMIF) provides USD 1.5 billion through 2030 to boost domestic critical mineral production, with funding for REEs and copper projects in 2025-2026.
European Union	The Critical Raw Materials Act (May 2024) sets binding 2030 targets to source at least 10% of critical materials from EU mining, 40% from EU processing/refining and 25% from recycling. It streamlines permitting and financing and promotes domestic scrap collection, with 60 strategic projects selected to allow for greater access to financing and streamlined permitting.
European Union	The Waste Shipments Regulation (May 2024) restricts recyclable waste exports outside the EU to boost domestic scrap processing and recycling capacity. It builds on the WEEE (Waste Electrical and Electronic Equipment) Directive, which classifies solar panels as e-waste and requires manufacturers to fund recycling under Extended Producer Responsibility.
Germany	The Resilience Roadmap for Permanent Magnets (August 2025) was developed by the German Federal Ministry for Economic Affairs and Energy and industry associations to reduce import dependence for permanent magnets and strengthen the resilience of the German and European wind energy industry.

Country	Policy
United Kingdom	The Circular Critical Materials Supply Chains Programme (2024), with GBP 15 million in funding, aims to strengthen the domestic REE supply chain – from mining through magnet manufacturing to recycling.
United States	The executive order establishing the National Energy Dominance Council (February 2025) aims to co-ordinate efforts on natural resources, including critical minerals.
United States	The executive order on Immediate Measures to Increase American Mineral Production (March 2025) aims to rapidly expand domestic mining, processing and refining of critical minerals, including copper, silicon, silver and REEs, and speed up permitting.
United States	The One Big Beautiful Bill Act (July 2025) phases out tax credits for domestic extraction, processing and recycling of critical minerals, starting in 2031 and ending entirely by 2034.
United States	Following a Section 232 probe, a 50% tariff on imported copper was applied on 1 August 2025 to protect domestic production.

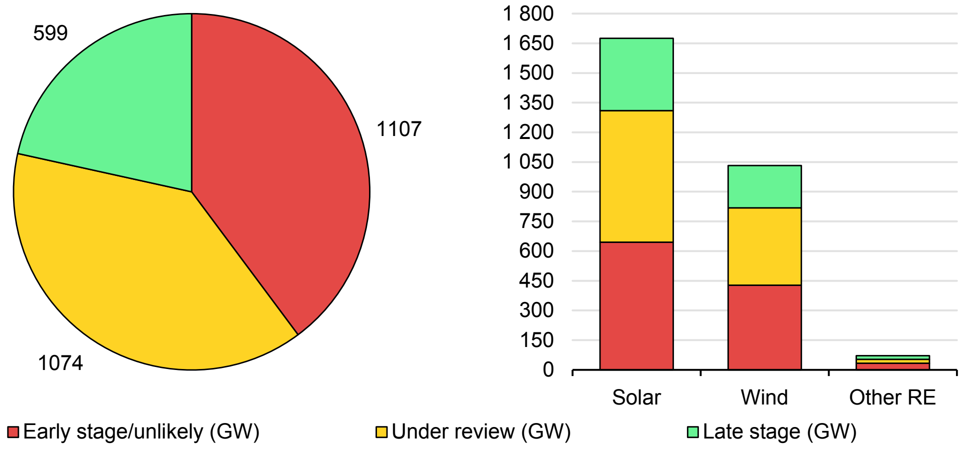
Grid connection queues

Advanced-stage projects remain stable, but a decline in early-stage grid connection applications may indicate a slowdown in the overall project pipeline

Since the IEA began tracking grid connections queues in 2023, projects in advanced stages of development have been stable. In the countries surveyed, around 1 700 GW of projects were at an advanced stage of development in mid-2025. Capacity from advanced-stage projects has remained consistent despite decreases in the two largest markets surveyed, the United States (-23%) and Spain (-18%).

There are two reasons for the reduction in the US project pipeline: first, ongoing queue-clearing reforms implemented by FERC; and second, a slowdown in development due to policy uncertainty. For instance, nearly 10 GW of offshore wind capacity in one single US load zone exited the interconnection queue following introduction of an executive order halting offshore wind development. In Spain, high volumes of both solar PV and wind power connected to the grid in 2024 and, while another robust year for development is expected, a slowdown is anticipated due to concerns over curtailment.

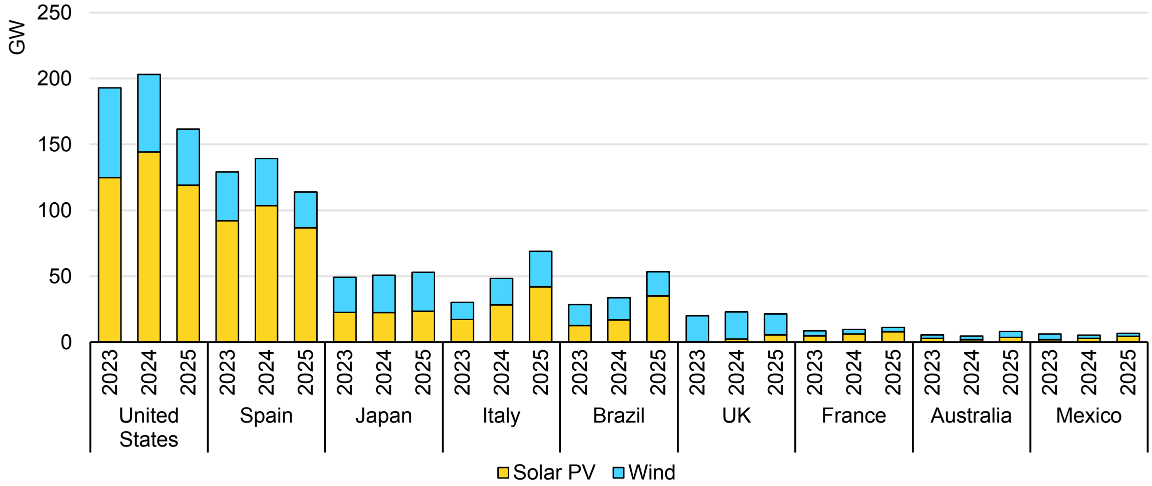
Renewable energy capacity in connection queues by project stage



Notes: RE = renewable energy. Capacity totals are based on publicly available country-level connection queue information. US data is from CAISO; ERCOT; MISO; PJM; NYISO; ISO-NE and SPP interconnections; Appalachian Electric Cooperative; Arizona Public Service; Black Hills Colorado Electric; Bonneville Power District; Cheyenne Light, Fuel & Power; City of Los Angeles Department of Water and Power; Duke Carolinas; Duke Florida; Duke Progress; El Paso Electric; Florida Light and Power; Georgia Transmission Company; Imperial Irrigation District; Idaho Power; Jacksonville Electric Department; Louisville Gas and Electric Company and Kentucky Utilities Company; NV Energy; Portland General Electric; Public Service Company of New Mexico; Platte River Power Authority; Santee Cooper; Southern Electric Corporation of Mississippi; Southern Company; Salt River Project; Tucson Electric Power; Tri-State Generation and Transmission; Tennessee Valley Authority; and Western Power Administration. Spain data is from Red Eléctrica de España. Japan data is from Hokkaido Electric Power Network, grid connection status of renewable energy projects; Tohoku Electric Power Network, grid connection status of renewable energy projects; TEPCO Power Grid, grid connection status of renewable energy projects; Chubu Electric Power Grid, grid connection status of renewable energy projects; Hokuriku Electric Power Transmission & Distribution, grid connection status of renewable energy projects; Kansai Transmission and Distribution, grid connection status of renewable energy projects; Chugoku Electric Power Transmission & Distribution, grid connection status of renewable energy projects; Shikoku Electric Power Transmission & Distribution, grid connection status of renewable energy projects; Kyushu Electric Power Transmission and Distribution, grid connection status of renewable energy projects; Okinawa Electric Power, grid connection status of renewable energy projects. Brazil data is from ANEEL. Italy data is from TERNA. UK data is from Ofgem. Germany data is from Bundesnetzagentur. Australia data is from AEMO. Mexico data is from CENACE. France data is from Service des données et études statistiques (SDES). Chile data is from CEN. Colombia data is from UPME. India data is estimated based on CEA transmission buildout planning. Solar PV values are a mixture of AC and DC, depending on the source.

Meanwhile, the number of projects in the early stages of grid connection continues to decline, with a nearly 15% drop compared to last year's survey. The largest year-on-year reductions in early-stage capacity were in Brazil (-71%), the United States (-36%), Australia (-12%) and Italy (-1%). These drops result partly from ongoing efforts to reform interconnection queues. If these reforms proceed as planned, early-stage project capacity could decrease even further. For example, the United Kingdom aims to remove 750 GW of capacity currently waiting in its grid queue, while the PJM Interconnection in the United States expects to process around 230 GW of project applications over the next few years. In Brazil, approximately 10 GW of capacity was withdrawn under the Day of Amnesty initiative in 2023.

Solar PV and wind projects in late-stage development by market, 2023, 2024 and 2025



Reform processes aim to reward continuous project development and combine project reviews

There is no one-size-fits-all approach to queue reform, as each market has its own challenges. However, two common reforms have been widely implemented to improve the grid connection process. The first involves shifting from a first-come-first-served to a first-ready-first-served approach. In the traditional model, projects are reviewed in the order they enter the queue, regardless of whether they are prepared to move forward. While this system worked when queue volumes were low, the surge in renewable energy development has significantly increased application volumes and extended wait times. As a result, many queues are now clogged with “zombie” projects – those unlikely to advance – blocking the progress of more viable ones.

In contrast, a first-ready-first-served model prioritises projects that have made progress towards development and are ready for connection. Those having reached key milestones – such as securing land rights, permits or financing – are given priority in the review process, accelerating their grid connection. Several markets have implemented this approach. In the United States and the United Kingdom, which are currently transitioning to this model, the review process remains largely unchanged but now includes readiness criteria to determine priority. In other markets such as Italy and Spain, the first-ready-first-served model is applied through strict permitting deadlines; only projects that meet these deadlines can move forward in the queue.

Defining characteristics of queue processes by country

Country	Organisation	Queue type or proposed reform
Australia	AEMO	Defined timelines and process guidelines
Brazil	ANEEL	Priority for ready-to-build projects
France	RTE	Proof of network capacity required before building
Germany	BNetzA	First ready, first served
Italy	TERNA	Milestone-based project tracking
Japan	METI	Fast track for storage projects
Mexico	CNE	Streamlined permitting for self-consumption projects
Spain	Royal decree	Strictly enforced project timelines
United Kingdom	Ofgem	First ready, first served
United States	FERC	First ready, first served

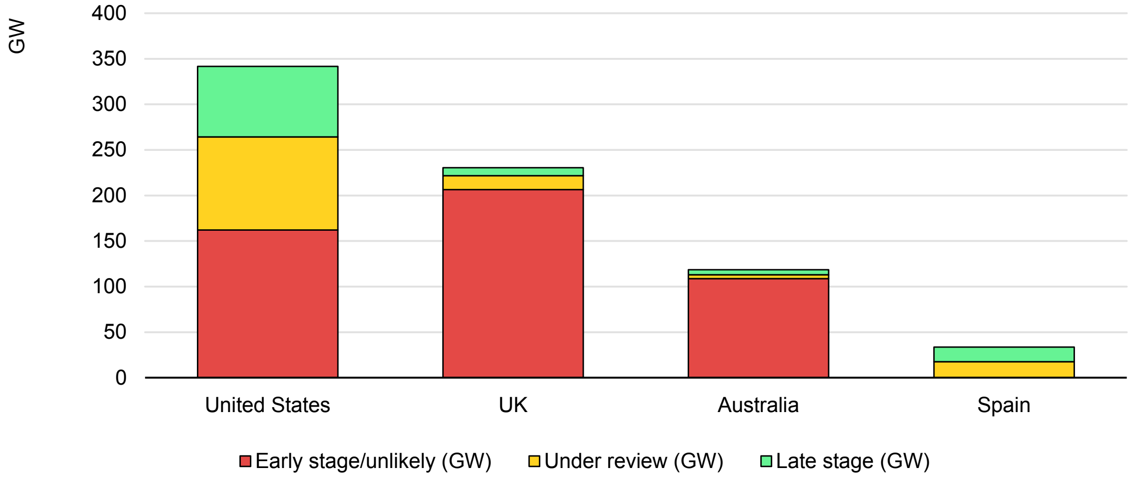
The second major way countries are speeding up connection processes is through cluster studies. Current systems usually review one project at a time, increasing wait times (and potentially costs) for developers. In contrast, cluster studies enable the simultaneous review of multiple projects, significantly speeding the grid connection process. In addition to accelerating the review procedure, cluster studies offer additional benefits, such as improving overall system planning and allowing grid upgrade costs to be shared among multiple project developers.

Higher volumes of project capacity are being paired with energy storage

Higher variable renewable energy penetration has led to an increasing need for energy storage. We estimate that there are currently over 600 GW of standalone battery storage systems awaiting connection globally, while an additional 125 GW of hybrid systems (energy generation technologies paired with a battery energy storage system) are in queues.

Many countries (e.g. South Africa, Greece, Italy and India) have held auctions for standalone storage capacity, while others (Spain and Portugal) use tender review systems that favour renewable energy systems paired with energy storage in auctions. The United States has the highest share of hybrid projects, but the United Kingdom and Australia also have several.

Standalone battery energy storage and hybrid systems in connection queues by development stage, June 2025



Financial health of renewable energy companies

With key regional developments impacting equipment manufacturers, developers and utilities, the financial health of renewable energy companies has evolved since last year. In China, ongoing oversupply-induced price competition that solar PV manufacturers began experiencing in 2023 has pushed the net margins of many into the negative. However, as wind industry production overcapacity is less prevalent, players could achieve stable positive returns.

Outside of China, the wind industry is recovering from previous losses because the macroeconomic environment has become more stable than in 2022 and 2023, when high inflation and interest rates were causing supply chain disruptions. Wind manufacturers in Europe and the United States have shifted their focus towards stricter financial discipline and supply chain risk management.

Overall investor sentiment concerning new capacity development remains strong. Developers with large and diverse generation portfolios are tending to maintain or further increase their renewable capacity deployment goals. However, considering recent policy changes both in the United States and Europe, some developers (mainly those focused on offshore wind) have revised their commitments to 2030. In general, several key trends in renewable energy investment prevail:

- **Agility**. Greater forecasting uncertainty has led many developers to commit less capital in advance and keep their short-term investment options flexible.
- **Investment diversification**. Utilities and renewable independent power producers (IPPs) are tending to balance out and expand the value streams in their

portfolios. Solar PV projects are increasingly coupled with storage solutions, improving their revenue options. Utilities that own networks are allocating higher capital shares to grids in their investment strategies.

- **Financial discipline**. Stricter risk management is leading to more transparent and often higher return expectations for new projects.
- **Risk mitigation along the value chain**. Stakeholders are responding to trade policy changes by turning their focus to value chain resilience. Many solar PV manufacturers are increasing vertical integration, while wind players aim to remove logistics constraints.
- **Maintaining a healthy balance sheet**. Apart from continued growth, maintaining overall healthy debt levels and financial valuation has become a focus for many developers.

Macroeconomic context

Because renewable energy technologies require substantial upfront investment and their operational costs are relatively low, their competitiveness (especially of wind and solar PV) is sensitive to all the main macroeconomic indicators. Higher inflation and interest rates increase the capital cost of renewables, so project delays and cancellations can result if policies do not adapt rapidly to the new macroeconomic environment. Elevated inflation also raises raw material and operational costs, increasing pressure on profitability for the renewable energy equipment manufacturing sector.

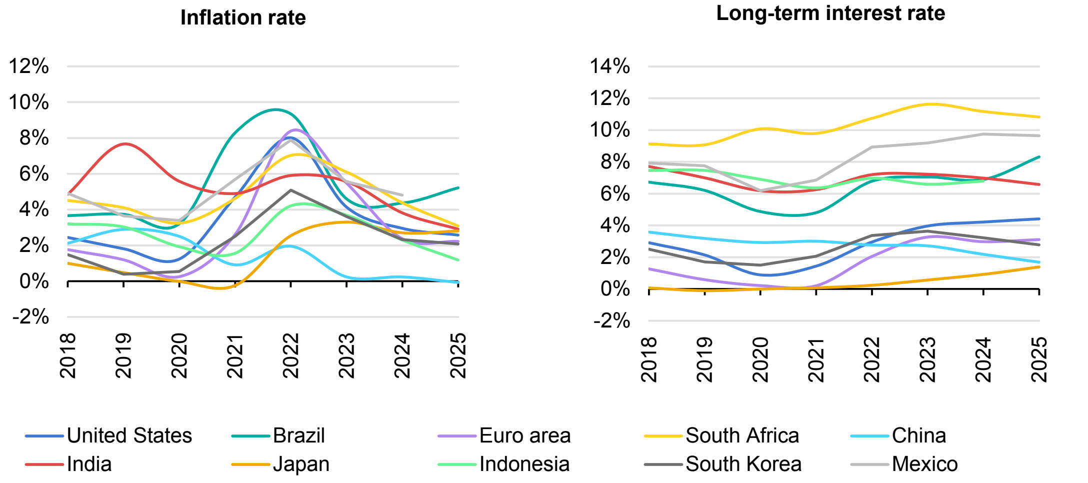
In 2022, many countries experienced a sharp rise in inflation, though rates have since declined. Today, inflation generally ranges between 2% and 5%, still about 1-2 percentage points higher than pre-2019 levels. According to the OECD 2025 mid-year outlook, inflation is expected to return to central bank targets by around 2026 in most countries.

Nevertheless, not all countries have been affected equally. For instance, current inflation levels in China, India and Indonesia are below their 2019 levels. In China specifically, year-on-year inflation has hovered around 0%, with some months even showing deflation.

Contrary to the decline in inflation since 2022, long-term interest rates have remained high. Most countries are maintaining a tighter monetary policy, resulting in about 1-3 percentage points higher long-term interest rates than during pre-2019. For emerging and developing countries, rates are generally 4-6 percentage points higher than in developed economies. Currency exchange risks and higher shares of government debt-to-GDP levels are the major influencing factors.

As long as interest rates remain elevated, further borrowing is likely to become more challenging. As inflation falls to neutral levels by 2026, interest rates are also expected to stabilise. China, India and Indonesia experienced a very low or even no increase in the past five years, making it possible for borrowers to take on debt under more favourable conditions.

Development of key macroeconomic indicators worldwide



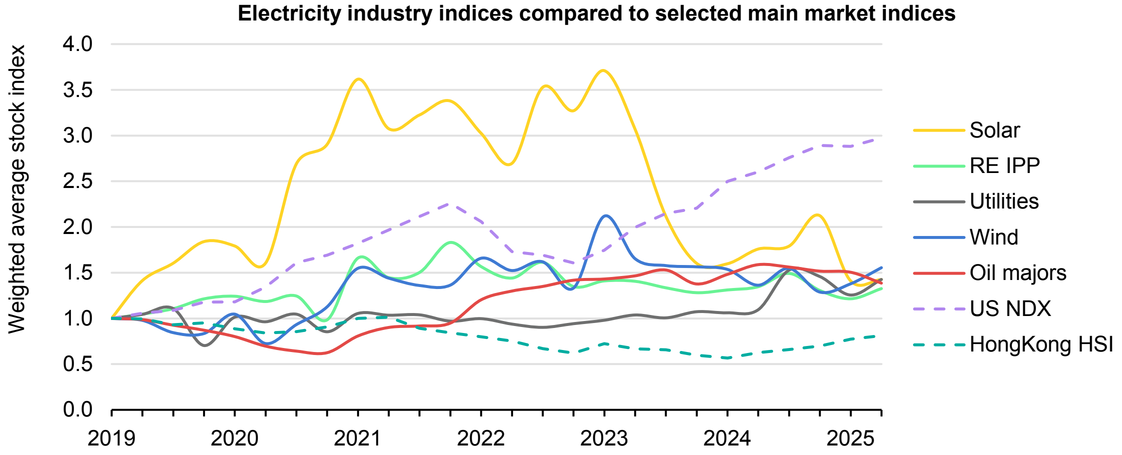
Source: IEA analysis based on data from OECD and national statistics offices for H1 2025.

Market evaluation

In the past, renewable component manufacturers and renewables-focused independent power producers have steadily outperformed the broader energy sector in equity markets. Before 2020, the stock price gains of traded companies in these sectors (-15% to 40%) had been higher than those of traditional utilities and other energy players (-40% to 10%).

By the end of 2020, after a temporary minor downturn during the Covid-19 crisis, the value of renewable energy industry stocks had risen sharply. For major solar PV and wind manufacturing companies, this jump resulted from strong demand, while renewables-focused IPPs could rely on long-term fixed contracts to provide stable future revenue streams. The renewable energy industry continued to generally outperform in equity markets up to the end of 2022.

Indexed stock market prices for traded energy companies and selected global indices, from a Q1 2019 reference point to Q2 2025



Notes: RE IPP = renewable energy independent power producer.

Solar companies (18): Jinko Solar Holding Co Ltd; SunPower; First Solar Inc; Canadian Solar Inc; Xinyi Solar; Trina Solar; JA Solar; LONGi Green Energy Technology; GCLSI; Risen Energy; Enphase Energy; Solaria Energia y Medio Ambiente; Daqo New Energy Corp; SolarEdge Technologies; Sunrun Inc; Vivint Solar; SMA Solar Technology; Hanwha Qcells.

Wind (12): Siemens Gamesa Renewable Energy; Acciona; Vestas Wind Systems; Xinjiang Goldwind Science & Technology Co Ltd; Suzlon Energy Ltd; China Longyuan Power Group Corp Ltd; Boralex; TransAlta Renewables Inc; Nordex SE; TPI Composites; Mingyang Smart Energy Group Co., Ltd; Windey Energy Technology Group Co., Ltd.

RE IPPs (15): NextEra Energy Inc; Orsted; MVV Energie; Innergex Renewable Energy; Brookfield Renewable Energy Partners LP; Adani Green Energy Ltd; Neoen SA; CPFL Energia; Algonquin Power & Utilities Corp; ERG SpA; Falck Renewables; Terna Energy SA; BCPG PCL; Infigen Energy; Enlight Renewable Energy Ltd.

Utilities (25): Enel SpA; Iberdrola SA; Electricite de France SA; E.ON SE; EDP; Engie; SSE PLC; Drax Group PLC; ACS Actividades de Construcción y Servicios; Tata Power; RWE AG; AES Corporation; Duke Energy Corporation; Sempra Energy; National Grid PLC; Xcel Energy Inc.; ACWA Power company, Neoenergia SA; CEMIG; Engie Energia Chile SA; ReNew Power Global plc; JSW Energy Limited; NTPC Renewable Energy Limited; ACEN Corporation; Kengen PLC.

Source: IEA analysis based on Bloomberg LP (2025), Markets: Stocks (Q2 2025) (database).

In 2023, persistently strong interest rates and inflation kept the cost of capital, raw materials and labour high, also affecting stock values. Furthermore, supply chain disruptions and long permitting wait times caused delays, especially for offshore wind. However, financial performance remained stable because demand was accelerating rapidly. In fact, renewable electricity generation capacity additions grew 50% globally (nearly 510 GW) in 2023.

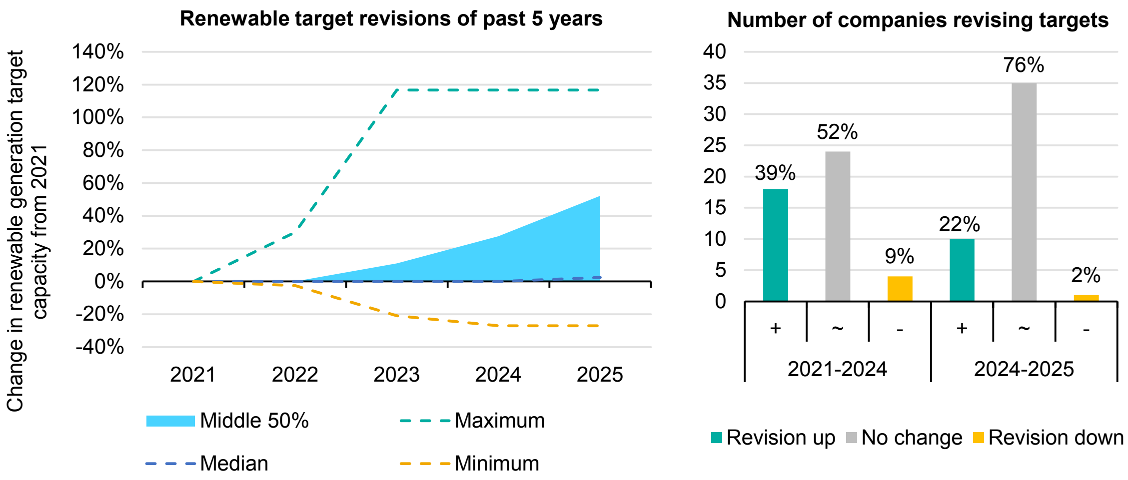
In 2024, changes to trade policies, including import tariffs and countervailing duties, caused market valuations of solar PV to fall again to 2020 levels. Signs of rebound appeared in the second quarter of 2025, with indices for the solar PV and wind industry, renewable IPPs and utilities rising slightly. Only oil company stocks have continued to decrease in value.

Investment sentiment

At the same time as many countries were developing renewable energy ambitions for 2030, renewable energy investors, including large utilities and IPPs, were also setting targets for that year to plan medium-term project development. Changes in these corporate capacity development targets are key indicators of investor sentiment for 2030. Our company-by-company assessment shows that, despite policy uncertainty, major renewable energy investors continue to be optimistic, with some raising their targets more than 100% and many more than 40% compared to 2021.

However, a target reduction of almost 30% is visible mainly at companies focusing primarily on offshore wind. In these cases, they seem to have shifted their sentiment and risk appetite from consistently accelerated growth towards more cautious and diverse commitments.

Changes to renewable generation capacity targets in the past five years, from a 2021 reference point to 2025



Notes: Analysed companies (46): ACWA Power; AES Andes; AGL Energy; CEMIG; CFE; Copel; Duke Energy; EDF; EDP; Enel; EnergyAustralia; Engie; EPM; Iberdrola; JSW Energy; KEPCO; Meralco; Masdar; NextEra Energy; ONEE; Origin Energy; Orsted; QatarEnergy; RWE; Tata Power India; TEPCO; EVN; Aboitiz Power; ACEN; Adani Green Energy; AMEA Power; Atlas Renewable Energy; Brookfield Renewable Energy Partners; Copenhagen Infrastructure Partners; Grenergy Renovables; NTPC Renewable Energy; Solaria; SSE Renewables; Toyota Tsusho; Vena Energy.

Sources: Renewable capacity targets announced in companies' annual reports, investment plans and publications of 2021-2025. Changes in short-term targets were compared to 2021 announcements, or the earliest target announcement if a 2021 data point was not available. For years in which no new target was announced, the last available target value was assumed to remain valid.

While measuring investor sentiment remains complex, we can discern some key trends based on recent policy and market developments worldwide.

Agility: Lower investment capital volumes and higher allocation flexibility

Most major utilities and leading renewable IPPs highlight a shift towards more flexible investment strategies to tackle uncertainty. A lack of commitment allows for future re-evaluation if the estimated market or policy environment changes.

Some are increasing their level of uncommitted capital to ~60%, while others are reducing the overall size of their short-term investment plan by 15-25%.

This trend is less prevalent among utilities in emerging markets, where capital allocation is more centrally determined by the state or local governments. Their investment strategies often reflect state-level policies and are generally less commercially driven.

Investment diversification: Multiple technologies, storage and networks

To reduce their risk profile, utilities and power producers aim to reduce as much as possible their EBITDA (earnings before interest, taxes, depreciation and amortisation) exposed to market volatility. Apart from hedging, risk can be reduced by increasing the volume of long-term fixed-priced sales through regulated price setting, power purchase agreements or other contracts. The current share of regulated or contracted EBITDA among many large utilities is 60-90%.

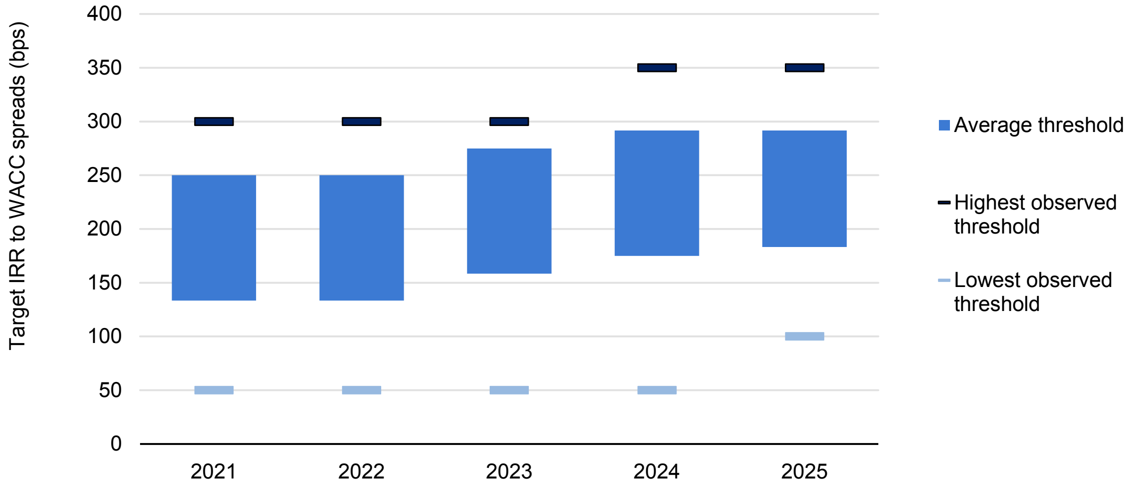
Some utilities are also investing more in distribution grids, retail businesses and transmission networks in specific geographies. These regulated assets provide stable and transparent returns throughout the regulatory period (usually four to six years each). Investments target resilience, storage, digitalisation, smart meter rollouts and new customer connections. The share of electricity network investment among the utilities analysed has increased 5-15 percentage points compared to 2024, representing 20-60% of overall planned capital allocations.

Financial discipline: Clear and updated investment criteria

In 2025, interest rates in advanced economies continued to be consistently higher than they were before 2022. As a result, project developers must adopt stricter financial discipline to secure affordable financing. They are increasingly focused on reassuring shareholders, lenders and rating agencies that capital is being invested efficiently in high-value projects.

To reflect this, many utilities and renewable IPPs now publicly disclose their investment criteria, typically requiring an internal rate of return (IRR) that exceeds their weighted average cost of capital (WACC) by 100 to 350 basis points – depending on the technology and project specifics. This means new projects must deliver returns of at least 1.0-3.5 percentage points above the cost of capital, a threshold that has risen by 0.5-1.5 percentage point from previous years. These growing return expectations also signal a reduced appetite for risk.

Development of investment criteria in the past five years for new renewable generation and storage projects



Notes: IRR = internal rate of return. WACC = weighted average cost of capital. The IRR to WACC spread represents the value created by the project over the minimum required return.
Analysed companies (6): EDP S.A.; Enel SpA; ENGIE SA; Orsted A/S; RWE AG; SSE Renewables Limited.
Source: IRR-WACC spread targets announced in companies' annual reports, investment plans and publications of 2021-2025.

Risk mitigation along the value chain: Focus on supply chains

In response to trade policy changes, industry players are redesigning activities along their value chains. For instance, major solar PV manufacturers are pushing for further vertical integration. By owning or managing more parts of the supply chain, they can increase control over costs and strategic planning. A prevalent strategy is to localise supply chain elements by establishing or boosting domestic production capacities. This can reduce costs by avoiding trade tariffs and increase resilience through self-sufficiency.

For wind manufactures, complex and strained logistics networks have created challenges in the past. Standardisation and reliance on proven solutions can reduce component-related costs, while designs adapted to transport-related infrastructure constraints (e.g. ports and shipping) can minimise bottlenecks.

Healthy Balance sheets: Steady debt and shareholder remuneration

The utilities and renewable IPPs we analysed often highlight their goal of maintaining a steady balance sheet and sustainable debt levels. Most of these large utilities and renewable IPPs have been (and plan to continue) sustaining a net debt-to-EBITDA ratio of less than four.

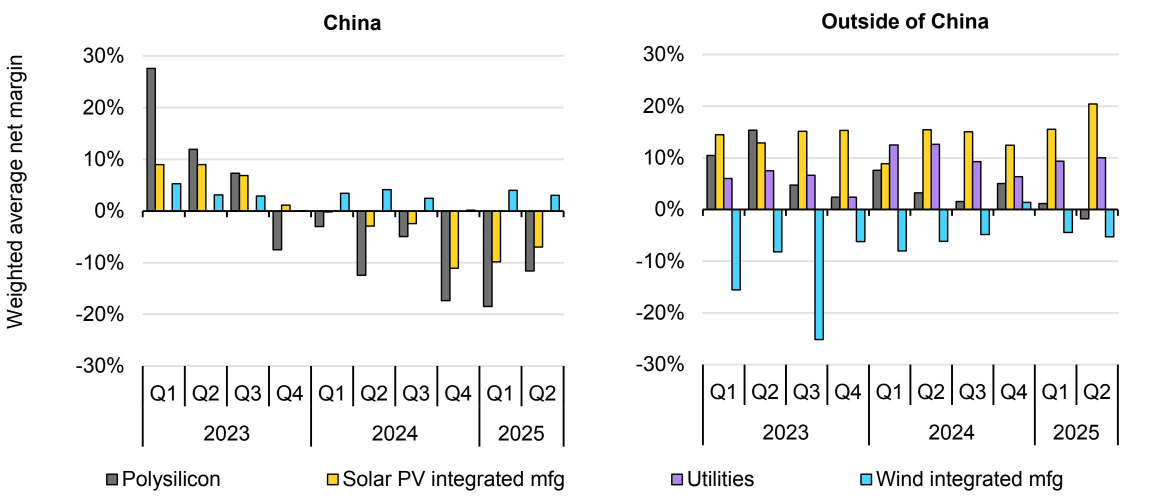
Continued growth ambitions are often coupled with announcements aimed at boosting investor confidence – either dividend payouts that are 5-15% higher than in 2024, or stock buyback plans. However, many still have a conservative payout strategy, retaining earnings for the investment pipeline.

The recent exit of six of the largest banks in the United States and the largest bank in the United Kingdom from the Net Zero Banking Alliance (NZBA) may also affect the use of financing to advance renewable energy deployment. In leaving the NZBA, these banks rescinded their commitment to align their lending and investment portfolios with climate targets and reduced the total assets of banks participating in the alliance by more than 20%.

Profit and loss

Between 2022 and 2024, prices for key solar PV components – including polysilicon, wafers, cells and modules – fell roughly 50%, mainly due to significant oversupply in China. Prices remained steadily low in the first half of 2025, placing continued pressure on manufacturer profitability throughout the entire supply chain.

Weighted average net margins of renewable energy companies and large utilities (Q1 2023-Q2 2025)



Note: mfg = equipment manufacturing companies.
Source: IEA analysis based on Bloomberg LP (2025), S&P Global Capital IQ (2025), annual reports, investment plans and publications for Q2 2025.

Despite growing PV demand in the next five years, overcapacity is expected remain considerable through 2030 (see the section on supply chain security). The margins of many integrated Chinese manufacturers of polysilicon, wafers, cells and modules fell to around -10% in Q4 2024, and the cumulative net loss of analysed China-based integrated solar industry companies since the beginning of 2024 totals around USD 5 billion.

Outside of Chinese integrated-PV manufacturers, two major companies are covered in this analysis: First Solar and Hanwha Qcells. Although representing a smaller share of the market, they continued to achieve healthy profits in 2024, accumulating a net income of around USD 1.3 billion in 2024. These companies follow premium pricing strategies for specific market segments. For instance, by differentiating themselves technologically through thin-film technology, they presented a unique market proposition for the US solar industry.

In wind manufacturing, the supply and demand balance is more geographically diverse than in the solar industry. Chinese wind component manufacturers consistently reported positive net margins, while the industry outside of China seems to be slowly recovering from the downturn of 2023.

Furthermore, Chinese wind turbine manufacturers have faced less disruption from inflationary and cost-of-capital challenges, and domestic demand has been strong. Wind turbine installations in China reached around 80 GW in 2024, with exports of more than 5 GW. Under these circumstances, the analysed companies maintained average net margins of 2-3%, resulting in a total annual net income of USD 0.9-1 billion in both 2023 and 2024.

For the wind industry outside of China, challenges in the macroeconomic environment and throughout the supply chain were more significant, especially for offshore wind. In the third quarter of 2023, net margins fell below -20% on average among large original equipment manufacturers (OEMs), leading to a cumulative net loss of around USD 5 billion for that year. Manufacturing base expansions have therefore been more cautious than in China. In 2024 the total annual net loss of the analysed wind component manufacturing industry outside of China decreased to around USD 1.2 billion.

The situation appeared to be stabilising in the first quarter of 2025, however net losses persisted. Several policy developments on permitting, auction design and financing, especially in Europe, have contributed to this trend. Many companies have shifted their focus from price competition to market share maintenance and quality improvement. Wind manufacturers outside of China are now focusing more on proven technological solutions, increasing the lifespan of existing wind turbine models and the range of available sizes.

Renewables and electricity prices

Rapid expansion in the use of renewable energy sources – such as wind and solar PV – is transforming electricity markets worldwide. Government subsidies have been crucial to support wind and solar PV deployment in the past, but with costs for these technologies now falling below those of fossil fuels power plants almost everywhere, the policy debate has shifted. Today, discussions focus less on subsidies and more on how renewables affect electricity prices, and the additional costs associated with their integration into the grid.

Unlike for traditional fossil fuels, the marginal costs of generating power from renewables are minimal, which often reduces wholesale electricity prices through what is known as the merit-order effect. As renewables claim a larger share of the electricity mix, they tend to reduce average electricity prices and dampen price spikes, while also introducing new challenges such as price volatility and the need for greater system flexibility.

As wind and solar PV plants provide inexpensive electricity in many countries through long-term contracts, many consumers question why their power bill costs have not also dropped. This disconnect stems from the complex relationship between wholesale electricity prices – which renewables often exert downward pressure on – and retail electricity prices, which include more than just the price of energy but also network costs, taxes and subsidy charges, all of which are set by a multitude of different stakeholders along the value chain. As a result, even as the cost of producing electricity from renewables falls, consumers may not see immediate or proportional reductions in their bills, raising questions over the impact of renewables on power affordability.

Furthermore, the relationship between electricity prices and industrial competitiveness adds another layer of complexity. For many manufacturing and heavy industry sectors, electricity is a fundamental input cost that directly affects their ability to compete in global markets. Even modest power price increases can impact profit margins, influence decisions about where to invest or expand, and determine whether operations remain viable in a given region.

Renewables and wholesale prices

Across many wholesale electricity markets, especially in Europe, a higher share of renewables in the power mix has consistently led to lower prices. This outcome stems largely from the lower marginal costs of renewable energy sources such as wind and solar compared with fossil fuels. When renewables supply a greater portion of electricity, they displace more expensive forms of generation, pushing overall prices down. The correlation between the share of renewables in electricity generation and hourly electricity prices is generally negative in Germany, Spain, the United Kingdom and France, where natural gas power plants usually set the hourly price.

To give context to the relationship between renewable energy shares and electricity prices in these countries, 2019, 2022 and 2024 are important years:

- 2019 can be viewed as the pre-crisis “normal” year when the share of renewables in electricity generation was already substantial. It predates the Covid-19 pandemic, which caused an exceptional drop in electricity demand and disrupted normal market dynamics.

- 2022 represents the height of the energy crisis triggered by geopolitical events and supply disruptions, particularly in natural gas markets.
- 2024 is included as a more recent reference point, reflecting a period when market stress from the energy crisis has eased but electricity prices remain elevated due to persistently higher gas prices.

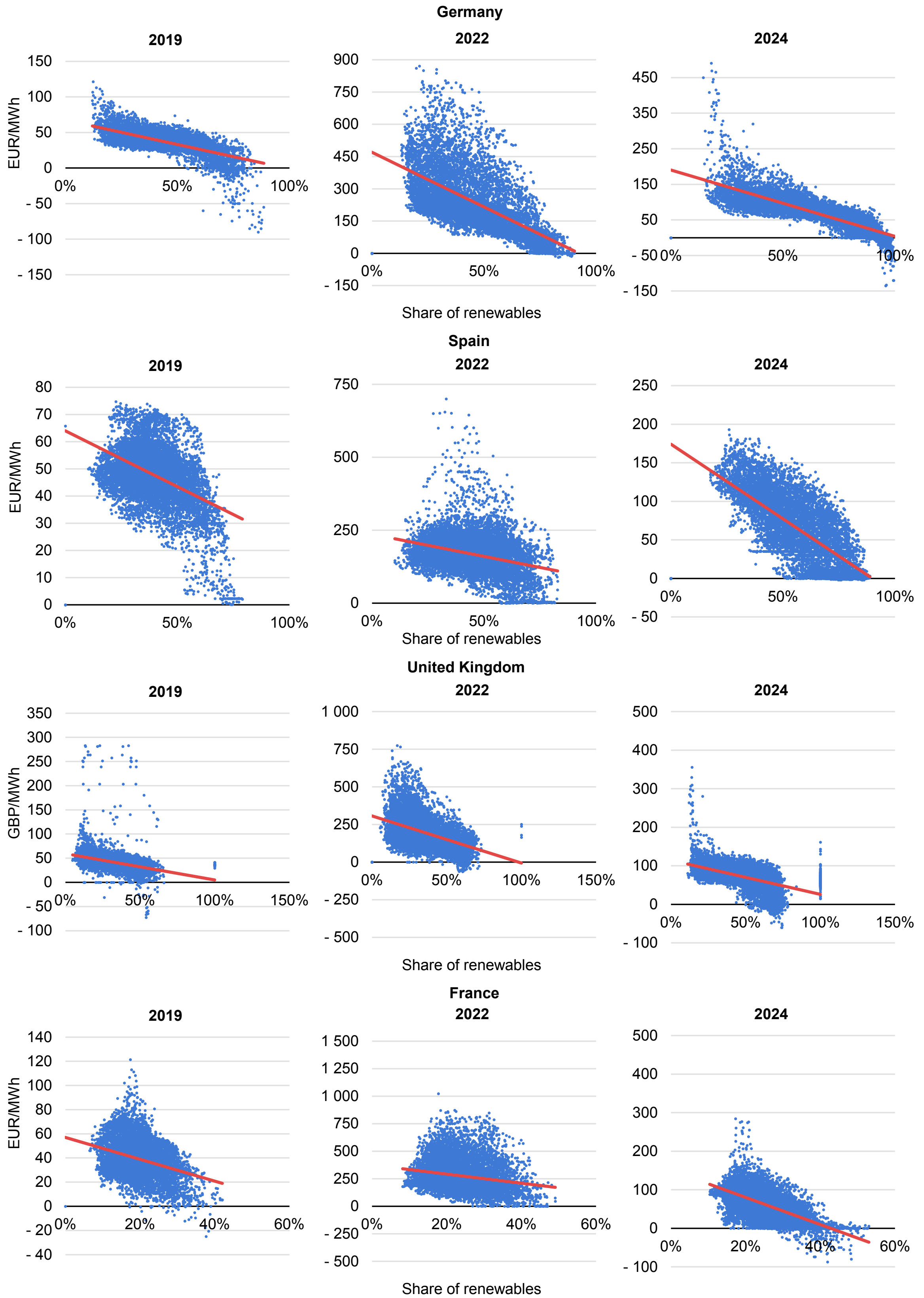
In 2019, electricity prices in Europe were around USD 50/MWh, 50% lower than in the first half of 2025. In Germany, the United Kingdom, Spain and France, higher renewable shares typically meant lower prices. The effect was moderate, reflecting a still-growing renewable energy sector. Regression lines in the scatterplots consistently slope downwards, indicating a price-suppressing influence from renewables even before the energy crisis.

Data from 2022 highlight how higher shares of renewables helped cushion the impact of fossil fuel price shocks due to the energy crisis, which led to significant price volatility. In most countries, the negative correlation between renewables and electricity prices became more pronounced, with higher shares of renewables helping to mitigate more extreme price spikes. In Spain, the introduction of a gas price cap in 2022 also contributed to price stabilisation, limiting the extent to which electricity prices could rise. Thus, the direct impact of renewables on price suppression was less visible than in other European countries.

In 2024, the downward electricity price trend resulting from higher renewable energy shares remained evident, and in some cases had become even sharper. Since the energy crisis, many European countries have accelerated the deployment of renewables. The full impact of these investments was visible last year, with renewables dampening the impact of fossil fuel prices on electricity markets.

Higher wind and solar PV shares correlate with a greater number of hours of negative electricity prices. This phenomenon usually occurs when wind and solar PV generation are stronger than demand in certain hours. This situation also indicates the lack of flexibility in the market. Because variable renewables have near-zero marginal costs and mostly fixed-price long-term contracts (either through policy schemes or bilateral agreements), they may continue to generate power even when prices fall below zero, further contributing to the overall decline in average wholesale prices.

Hourly wholesale electricity prices and shares of renewables in Germany, Spain, the United Kingdom and France, 2019, 2022 and 2024



From 2023 to 2024, the number of negative-price hours increased 12-fold in France (≈ 350 hours), doubled in Germany (≈ 460 hours) and grew 9-fold in the United Kingdom (≈ 230 hours). In Spain, negative prices were not allowed until mid-2021. Even as renewable electricity shares grew, the market design set the floor at zero. From January to July 2025, however, Spain had 460 negative-price hours.

Renewables and network costs

The cost of generating electricity from renewables has fallen dramatically, putting them among the cheapest energy sources for new power generation. However, the broader effects on electricity grid costs can be multiple.

Infrastructure costs

Allocating grid infrastructure costs directly to renewables is complex. The electricity grid is a highly integrated system, and costs arise from a mixture of factors (e.g. ageing infrastructure, rising demand, and the need for greater flexibility) – not solely from the addition of renewable electricity. Moreover, grid investments often serve multiple purposes, including to enhance reliability, support electrification and accommodate all types of generation. As a result, the costs associated with transmission upgrades, balancing and congestion are typically spread across all users and generators, rather than being attributed to renewables specifically.

Although it is necessary to allocate these mixed costs directly and indirectly to understand the "total" system costs of renewables (particularly for variable technologies), the reporting frameworks used by system operators and regulators do not generally separate out costs by technology type. Instead, expenses are aggregated at the system level, reflecting the shared nature of grid infrastructure and services. This makes it difficult to isolate the incremental costs linked to renewables from those stemming from other power system changes. The interconnectedness of grid operations, overlapping benefits and evolving nature of the supply-demand mix mean that allocating costs directly to renewables is both methodologically challenging and inconsistent with standard industry practice.

Balancing, congestion and curtailment

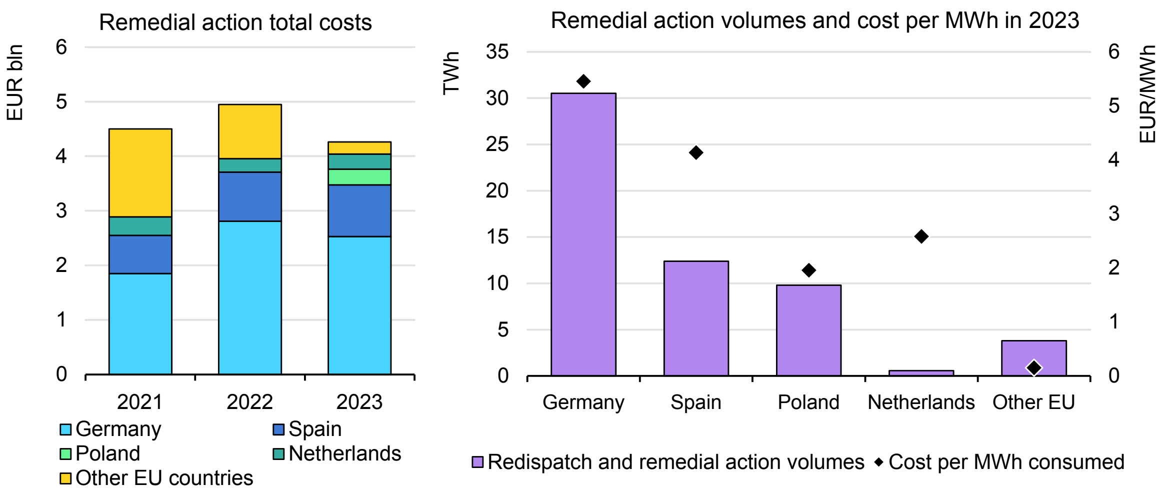
As wind and solar shares in the electricity mix increase, their variability also raises balancing, congestion and curtailment costs. Grid operators need to manage the mismatch between forecast and actual generation from variable sources. This may lead to additional balancing costs, as network operators need to redispatch and employ countertrading to match demand and supply in real time to maintain grid stability. Balancing costs vary depending on forecast inaccuracies, system flexibility limitations and transmission line congestion, including of interconnectors. High congestion and a lack of flexibility can lead to reduced renewables output or curtailment, incurring additional costs.

Separate from infrastructure costs, the economic impact of renewables on day-to-day grid management can be tracked when specific reporting is available. In Europe, renewables-related grid management measures are called “remedial actions,” and TSOs have recently begun to report them more consistently. As part of these actions, redispatching and countertrading are most associated with renewable energy integration.

Costs for these activities have been rising in several European countries where the share of variable renewables has increased rapidly but grid expansion has not kept pace. However, this expense may not necessarily be inefficient, as it might be more economical to pay a certain amount in redispatch costs rather than build out the network extensively.

EU grid congestion increased 14.5% in 2023, pushing system management costs above EUR 4 billion. However, this was a drop from the EUR 5 billion spent on remedial actions in 2022, thanks to lower natural gas and electricity prices. As renewables are increasingly curtailed to manage congestion, they are often replaced by fossil fuel generation.

Remedial action volumes and costs in the European Union



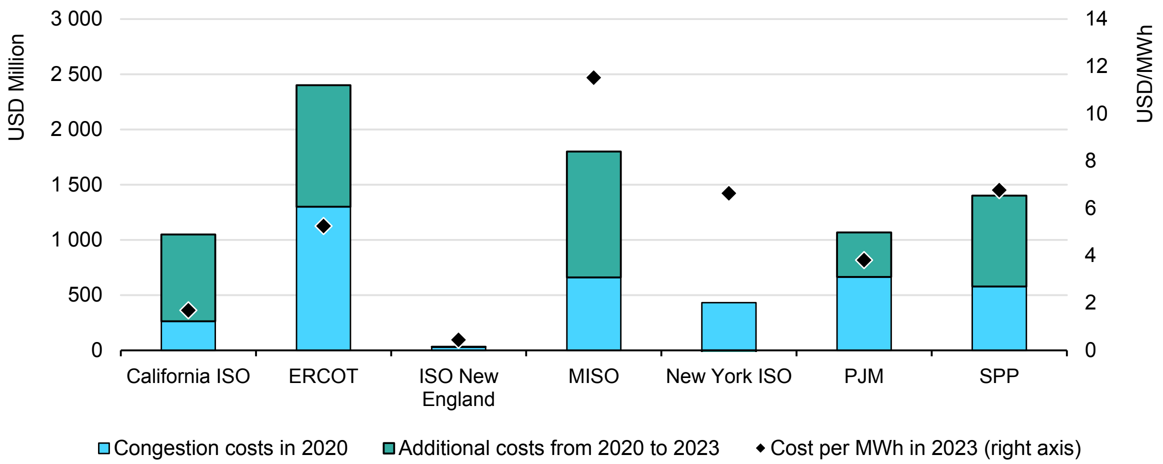
Note: “Cost per MWh consumed” is costs divided by consumption.
Source: ACER (2024), Transmission Capacities for Cross-Zonal Trade of Electricity and Congestion Management in the EU: 2024 Market Monitoring Report.

Among EU members, Germany, Spain, Poland and the Netherlands account for over 90% of all system management costs, mostly to integrate wind and solar PV. In 2023, remedial action volumes reached almost 60 TWh in the European Union, making up 2% of the bloc's electricity consumption. While costs associated with renewable electricity integration are increasing, they nevertheless remain relatively low.

Germany has the highest remedial costs relative to electricity consumed, at over EUR 5/MWh, followed by Spain at EUR 4/MWh and the Netherlands. In most European countries, the cost is still negligible. When congestion management costs are incurred, they represent 0.5-1.5% of a residential electricity bill. However, limited grid investments and rapid wind and solar PV expansion are expected to worsen congestion and increase remedial action costs over the medium term.

Congestion costs have also been rising in the United States, partly because shares of renewables are expanding. For most US independent system operators, curtailment rates have been increasing since 2020, leading to higher congestion management costs. ERCOT and MISO have experienced the largest rises in total congestion expenses, while the change for ISO New England has been minimal. The cost per megawatt hour also climbed in several regions in 2023, with MISO, ERCOT and New York ISO registering the highest values.

Day-ahead grid congestion costs in the United States, 2020 and 2023



Sources: IEA analysis based on data from CAISO, ERCOT, ISO New England, PJM, SPP, MISO and New York ISO.

The cost of congestion relative to energy consumption varies drastically among different US regions, ranging from less than USD 1/MWh in ISO New England to USD 12/MWh in MISO. While ERCOT has the highest volume of curtailed variable renewables in the United States, leading to high redispatch expenditures, the cost remains below USD 6/MWh. Limited grid availability across many US regions continues to be a key challenge to the cost-effective integration of variable renewables.

Renewables and retail electricity prices

Are renewables the cause of rising retail electricity rates? Are they responsible for reduced affordability for customers? The answers to these questions are complex, as retail prices are composed of many variables, making it difficult to analyse the impact of growing shares of renewables on retail prices. However, a closer look at the components of retail prices can provide some insights into future price developments.

What is included in retail electricity prices?

Retail residential electricity prices usually consist of four main components: energy costs; network expenses; government surcharges/taxes; and value-added tax (VAT). In each component, countries include various charges that are either fixed (per kW or per billing period) or variable (per kWh of electricity consumed). In retail competition markets, wherein consumers choose a supplier based on competitive offers, the retailer defines the energy component of the bill. However, policymakers and regulators usually set the network charges, government surcharges/taxes and VAT. These regulated components are usually charged based on energy consumed (per kWh), but many country-specific subcomponents can be fixed according to either connection size or annual/monthly payments.

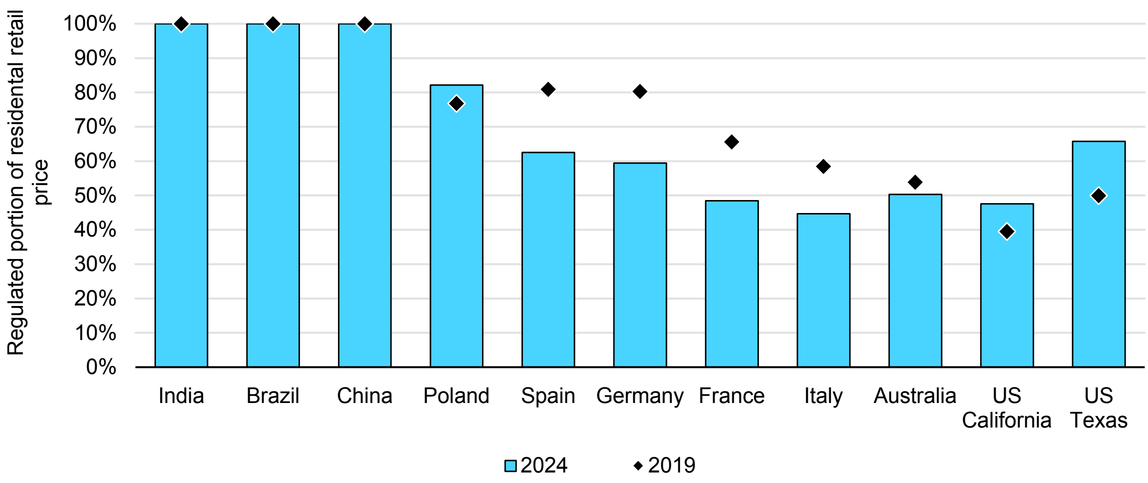
Electricity retail price per component

Component	What is it?	Regulated	Fixed or variable
Energy	Electricity generation costs and retailer margins	No in retail competition; Yes in regulated markets	Variable
Network	Transmission and distribution charges	Yes	Mostly variable, but countries increasingly include fixed capacity charges for various consumer segments
Taxes and charges	Country-dependent but can include surcharges for renewables, special electricity taxes, plant decommissioning, smart meter rollouts, environmental taxes, etc.	Yes	Mostly variable
VAT	Value-added tax can be specific for electricity; some vulnerable consumer groups can be exempt	Yes	% of the bill – some components can be exempt

Who sets retail electricity prices? The market or regulators?

The regulated share of the residential electricity price remains substantial in both advanced economies and developing markets, often comprising more than half of the total tariff. In many emerging and developing economies (e.g. India, Brazil and China), 100% of the residential tariff is typically defined by the government, regulator or other market authority responsible for price setting. In these countries, the retail price is set at the subnational level and takes local energy resources, grid development and economic growth into account.

Share of regulated components in residential electricity price in selected countries, 2019 and 2024



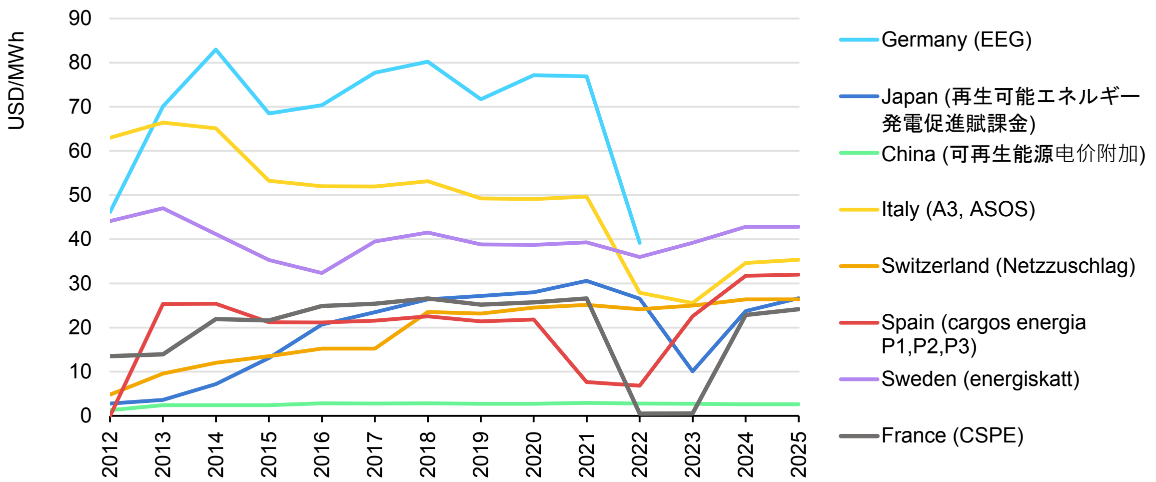
In advanced economies, governments regulate or define more than half of the residential electricity price, including network costs, government surcharges and taxes. The share was even higher in 2019 when energy prices were 30-40% lower than today. In addition, several European markets including France and Spain still maintain an optional regulated price for the energy component for all or some customer segments based on a formula that is indexed to market developments. In the United States, retail electricity prices are set at the state level, including distribution costs, but transmission charges are federally regulated.

Do renewable energy subsidies account for a substantial part of retail electricity prices?

Renewable energy subsidies or environment-related taxes – when mentioned explicitly in power bills – range from USD 2/MWh to USD 45/MWh, making up 2-15% of the total residential retail price in 2024. However, it remains challenging to track the impact of renewable energy surcharges on the price of electricity in most countries because governments can also choose to finance renewables through taxes and not through electricity bills. In addition, the government surcharge and tax component of the retail price tends to include multiple additional items that may or may not be related to renewables, making it difficult to isolate the cost impact of renewables on customers. These additional charges may pay for electricity subsidies for vulnerable consumer groups; waste management; the repayment of electricity system debt; the decommissioning of old nuclear or fossil fuel infrastructure; and other incidental costs.

Electricity bills in Germany, China and Japan distinctly itemise renewable energy subsidies. In Germany, the Renewable Energy Surcharge (EEG) was removed from retail prices during the energy crisis in 2022. EEG charges had peaked at nearly USD 80/MWh in 2014 and 2018, making up roughly one-quarter of the total residential electricity price. By 2022, just before its removal, the surcharge had fallen below USD 40/MWh – less than 10% of the total price – mainly because wholesale electricity prices had risen. In the upcoming decade, overall renewable energy support costs are expected to decline because EEG payments for most renewable capacity receiving high financial support will end, while new installations will require limited or no financial support.

Renewable energy surcharges for retail consumers in selected countries, 2012-2025



In Japan, the renewable energy surcharge has increased steadily since 2012, reaching nearly USD 25/MWh in 2025. This rise stems primarily from the feed-in-tariff (FIT) policy, which has been updated periodically to reflect the declining cost of renewables. **In contrast, China has maintained its renewable surcharge at just under USD 2/MWh since 2012**, using these funds to cover additional costs associated with feed-in tariffs. However, the Ministry of Finance has noted a growing tariff deficit in renewable energy subsidy collection. Although

China ended its FIT policy five years ago, the surcharge remains on electricity bills at the same level to address this accumulated deficit.

In several European countries (e.g. Italy, Spain, Switzerland, Sweden and France), government-imposed charges on electricity bills bundle renewable energy funding with other components such as environmental taxes, support for vulnerable consumers, and costs related to nuclear decommissioning. Renewable energy is estimated to make up the largest portion of these charges, which typically range from USD 25/MWh to USD 40/MWh. During the spike in wholesale electricity prices in 2022 and 2023, these government charges were temporarily reduced.

However, as many European nations have accelerated renewable energy deployment to enhance energy security in response to reduced Russian natural gas imports, these charges have returned to almost pre-crisis levels. Most of these charges are still being used to pay for the generation fleet that was established when wind and solar resources were more expensive than the alternatives. In the last five years, new onshore wind and solar PV plants have been the cheapest source of electricity generation in most European countries.

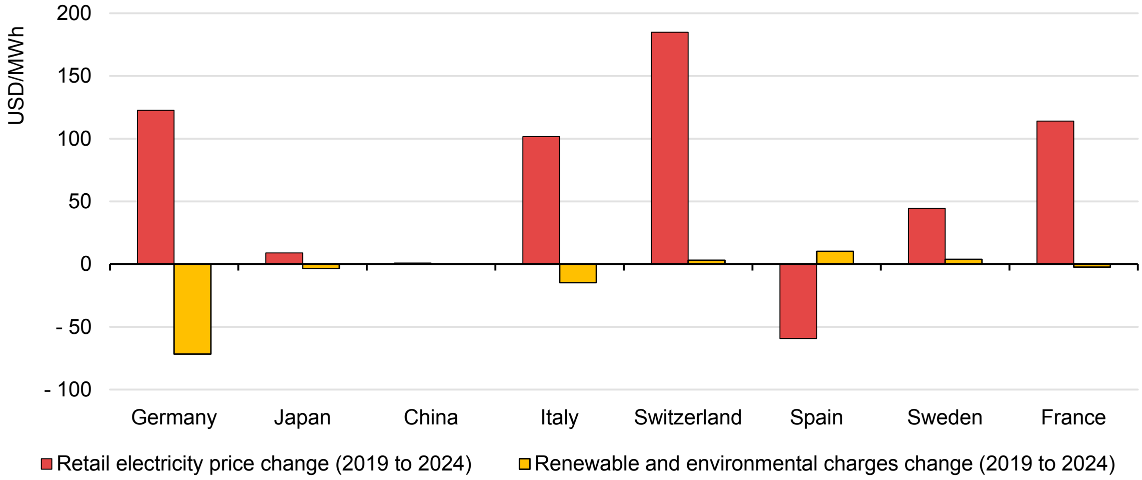
Are renewable energy subsidies the main cause of higher electricity prices?

For countries that we directly or indirectly tracked renewable energy-related surcharges, the data show that this component remained largely stable while total electricity prices increased. In Germany, the major drop in the government-charges component reflects EEG removal from the retail electricity price, while energy and network cost increases have counterbalanced this decline since 2019, leading to higher overall prices for households. In 2025, EEG costs are estimated to be around EUR 17.2 billion, or less than EUR 60/MWh, which will be part of the federal budget financed through tax revenues.

In Italy, France, Switzerland and Sweden, higher wholesale prices following the energy crisis have been the main reason for the overall increase in retail rates. In most of these countries, governments actually reduced additional charges to improve affordability while renewables surcharges remained stable, not impacting the overall electricity bill.

In Spain, retail rates are lower than in 2019 because government charges and taxes were reduced during the crisis. However, some of these charges are already back to their original level and should raise overall rates in 2025. **Renewable energy surcharges are expected to decline over the next decade, as a large number of 20- to 25-year subsidies were locked in during 2010-2015 when wind and solar PV generation was significantly costlier.**

Changes to residential electricity prices and renewable energy/environmental surcharges, 2019-2024



What is the main driver behind retail electricity price increases?

Residential electricity prices have increased in many advanced economies as well as in emerging and developing countries over the last five years. However, the scale of the increase and the reasons vary drastically among countries.

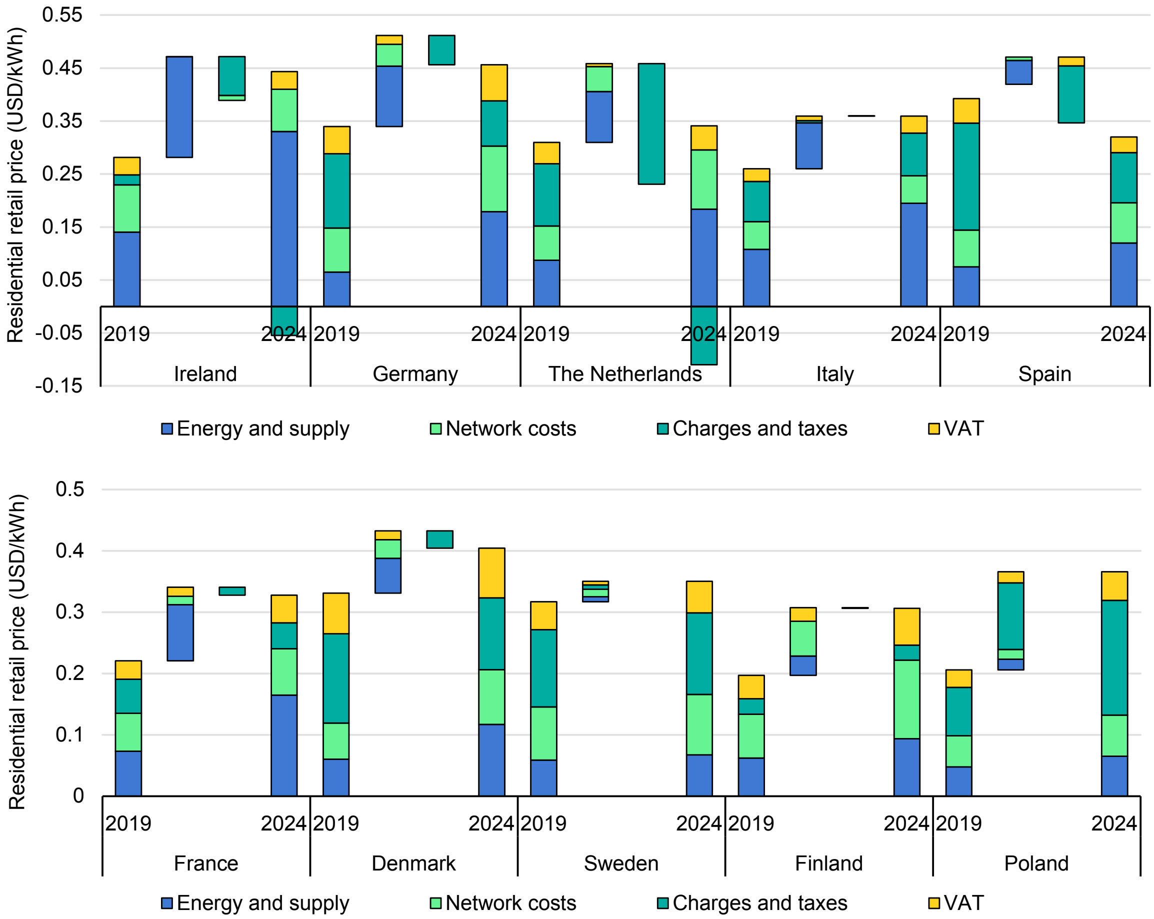
European Union

EU countries have some of the highest residential electricity prices in the world, but the range is wide. Prices are highest in Ireland and Germany at about USD 0.45/kWh, and lowest in Bulgaria and Hungary at around USD 0.11/kWh. In many EU countries, retail electricity prices increased 20% to more than 50% during 2019-2024.

Elevated energy supply costs were the main reason for higher retail bills in Europe. The energy crisis after Russia's invasion of Ukraine caused natural gas prices to rise sharply, pushing EU electricity prices to record highs. In fact, gas prices in 2022 were more than nine times higher than in 2019. Although prices have since declined, they are still two to three times higher than pre-Covid-19.

The rapid expansion of renewables following the crisis prevented much larger increases in European electricity prices. In 2022, in the middle of the energy crisis, natural gas-fired power plants set almost 60% of the wholesale electricity price on average. By 2024, the role of gas had declined to 30-50% owing to a higher penetration of renewables. Thus, over 2021-2023, EU electricity consumers saved an estimated EUR 100 billion thanks to newly installed solar PV and wind capacity.

Residential retail electricity prices by component in selected EU countries



Since 2019, the energy supply portion of electricity bills has doubled in almost all EU member states. However, countries with a high share of renewables and less reliance on gas-based generation experienced much smaller increases. Five years ago, energy supply costs made up 20-35% of an EU residential consumer's electricity bill. In 2024, this share increased to 40-80% due to higher wholesale electricity prices.

In Ireland, consumers pay around USD 0.33/kWh for the energy component, the highest rate of all EU countries, while in Hungary this portion is regulated and remains 90% lower owing to extensive government subsidies. In Nordic countries, the energy component of electricity prices is around USD 0.06-0.07/kWh, thanks to a substantial share of renewables in their electricity mix. In most large European economies including Germany, Spain, Italy, France and the Netherlands, consumers pay USD 0.11-0.20/kWh for the energy component of their bills.

Trends in network-charge changes in EU countries are mixed. In some economies, consumers have experienced a doubling of network charges on their electricity bills. In others, the cost of network charges has remained largely unchanged. On average, network charges account for 15-25% of residential electricity bills in many EU member states.

In Germany, the Netherlands, Finland, Denmark and Sweden, substantial increases in network investment are being passed along to consumers. Rapid renewable energy expansion (among other factors) has made additional investments necessary to connect wind and solar PV plants. However, some countries (e.g. Spain and Italy) have managed to keep network costs stable for residential consumers despite the growing share of renewables.

Policy intervention in many countries has reduced government surcharges and taxes on electricity bills to protect consumers and improve affordability. In Ireland and the Netherlands, governments have been offering direct payments or tax credits to residential consumers, effectively removing the impact of all government surcharges and taxes from electricity bills. The German government removed the EEG component, while Spain, France and Denmark reduced special electricity tax rates. Most EU countries have kept the VAT rate unchanged or implemented small short-term reductions.

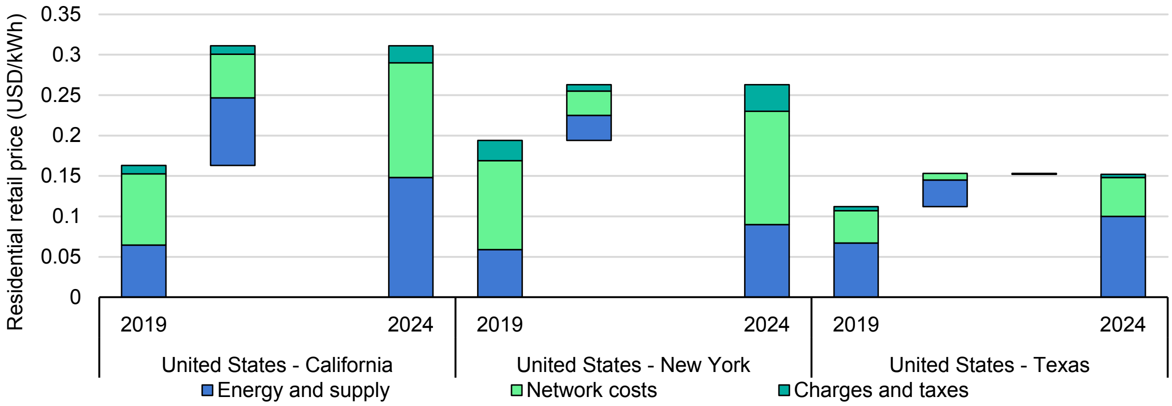
The United States

Between 2019 and 2024, US residential electricity prices increased notably in key states such as California, New York and Texas. The significant hikes in California and New York were driven primarily by higher energy supply costs and rising network charges. In contrast, Texas experienced more moderate increases, maintaining the lowest prices of the three states.

Across these states, energy and supply remain the dominant cost components, but New York and California also registered increases in network charges, as well as in government charges and taxes, further adding to consumer bills. In California, fire mitigation and related insurance costs have also contributed to higher charges.

Despite these increases, US electricity prices in 2024 remained lower than in most major European countries. In Europe, the energy component of residential prices in large economies is typically in the range of USD 0.11-0.20/kWh. A key structural feature favouring US consumers is the absence of VAT on electricity bills in many states. In the European Union, VAT commonly adds 5-27% to residential rates, compounding price surges.

Residential retail electricity prices by component in selected US states



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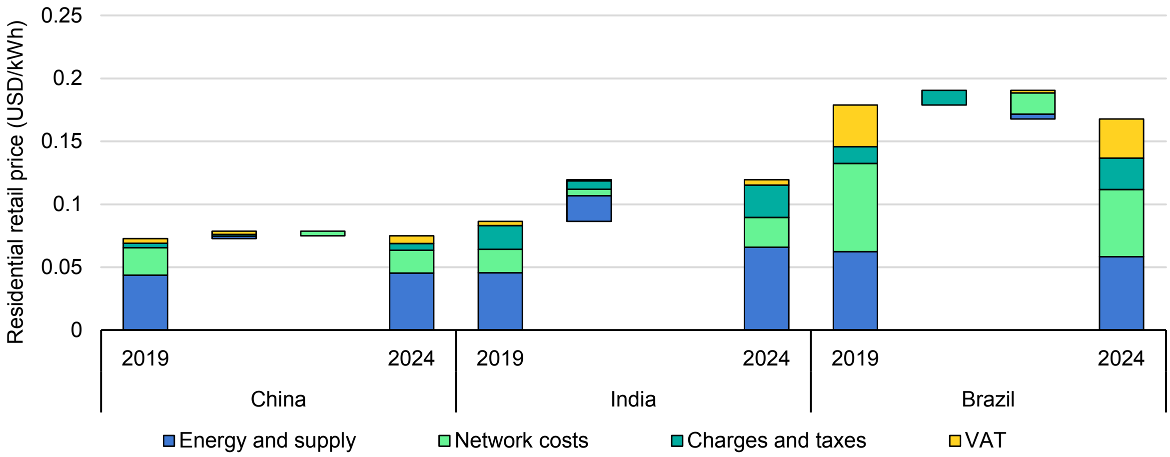
China, India and Brazil

In most emerging economies, residential electricity prices are regulated and can be significantly lower than in advanced countries. Protecting vulnerable consumers and improving affordability are the main goals of price regulation. Unlike in advanced economies, electricity prices are lower for residential customers than for commercial and industrial consumers.

Residential retail electricity prices by component in China, India and Brazil



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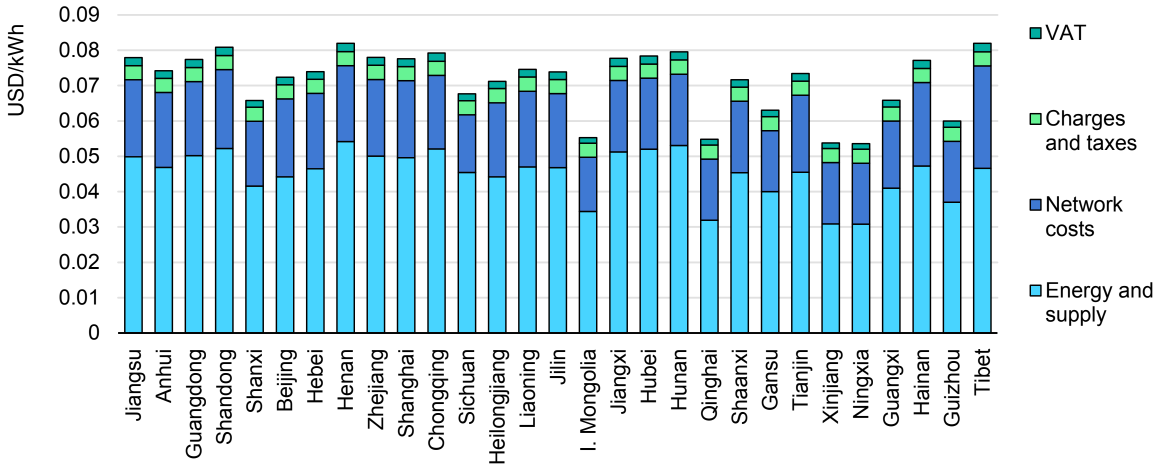
In China, nationwide average residential electricity prices have remained almost unchanged at around USD 0.075/kWh since 2019. Slight energy supply and surcharge increases have been compensated for by a decline in network costs. Thus, Chinese residential consumers pay one of the lowest electricity prices worldwide. Energy supply accounts for almost 60% of the bill, followed by network costs. The energy component of the residential rate is defined for each province based on provincial benchmark prices plus a 10-15% reduction. A similar reduction is applied to network costs, which are province-specific.

The lowest residential electricity costs in China are in Ningxia province, where a combination of inexpensive coal and affordable renewables keeps prices just above USD 0.05/kWh. Xinjiang follows closely behind, with only slightly higher rates. In contrast, retail prices for residential electricity in provinces such as Henan and Shandong are approximately 60% higher than in the lowest-cost regions, exceeding USD 0.085/kWh largely because of higher energy supply costs.

Network costs in China also vary by province due to differences in grid constraints and the scale of distribution networks, but these factors impact the total price less than energy supply costs do. Government surcharges also include payments for renewable energy subsidies, but account for only 5-7% of the residential electricity bill. They remain consistent across all provinces.

Residential retail electricity prices by component and province in China, 2024



India's exposure to higher fossil fuel prices shows in its 25% rise in retail electricity prices since 2019. The energy component of India's power bills accounts for most of the increase, but government surcharges have also been climbing. Within these surcharges, however, renewable energy subsidy payments make up less than 1%, as solar PV and wind power have been significantly cheaper than coal and natural gas alternatives since 2022.

In Brazil, retail prices have declined in USD terms since 2019 but have risen in local currency. Higher government charges are mostly responsible for the increase, as they include multiple federal, state and sectoral taxes on a percentage basis, applied to the overall bill. Higher energy and network costs in nominal currency contributed to the price rise over the last five years.

Does the energy component of retail rates reflect wholesale electricity prices?

The ongoing energy crisis has led to a widening gap between prices paid by utilities on the wholesale market and rates ultimately charged to consumers. This growing disconnect has put increasing financial pressure on households. The energy component of the retail electricity price usually includes the cost of electricity supply, delivery fees (excluding T&D charges, which are regulated and charged separately), and a utility or retailer profit margin. In liberalised markets with retail competition, costs for retailer trading activities (including hedging and risk allocation) are also reflected in the energy component.

In most European markets, the energy component of the retail price has been significantly higher for residential customers than for commercial and industrial consumers that have access to more competitive long-term deals. Government policies usually prioritise lower industrial prices to increase competitiveness, especially for strategic industries.

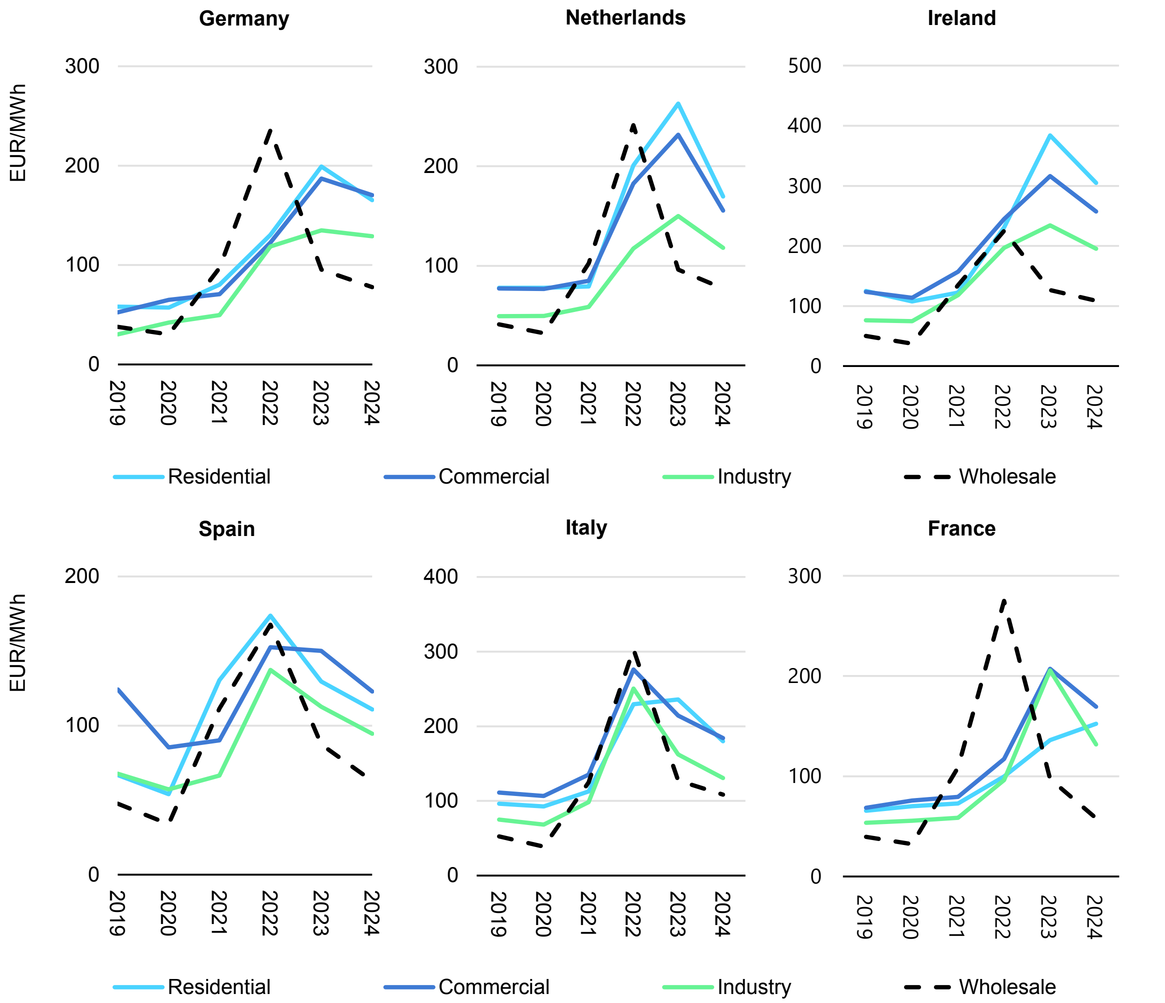
Before the energy crisis, the wholesale market price and the energy component of retail rates were highly connected. **However, the gap between wholesale electricity prices and residential rates continues to grow, directly impacting consumers – especially households – since the energy crisis.** As a result, after the institution of protection measures in several countries, many residential customers are now paying significantly more than current wholesale prices, preventing them from benefiting from relatively lower market prices thanks to a growing share of renewables**.**

Two factors have led to this challenging situation for consumers.

First, at the peak of the energy crisis, some retailers did not fully reflect the high-price environment to consumers due to surging natural gas prices, or governments intervened through regulatory caps. However, prices had surged drastically, creating a considerable gap between the energy component of retail rates and the wholesale price in 2023-2024 and the first half of 2025. For instance, large German utilities only partially passed record-level prices on to their customers, often because they had long-term hedging strategies in place. Utilities that had not contracted their generation assets reported record-level profits because they benefitted from the high prices. Meanwhile, many smaller retailers posted losses because of higher exposure to risk in the absence of generation assets.

However, all retailers generally doubled their energy prices for consumers with a year's lag in 2023, while at the same time wholesale electricity prices more than halved. In 2024, German consumers paid EUR 180/MWh on average for their energy (excluding network costs and other charges), slightly below the 2023 peak price, while the wholesale price was around EUR 80/MWh. This large gap should narrow by the end of 2025 with consumers also benefiting from the lower-price environment.

Energy component of retail rates for residential, commercial and industrial consumers vs average wholesale electricity prices in selected European markets



In France, a similar pattern emerged. In 2022, regulatory measures shielded all customer segments from soaring wholesale energy prices, limiting the energy component of retail prices. At the height of the crisis, French consumers were paying only about one-third of the wholesale price. In 2023, however, retail electricity prices more than doubled even though wholesale prices had fallen more than 70%. The energy portion of residential retail prices is expected to remain relatively high to offset earlier losses. EDF, the country's largest utility, reported EUR 17 billion in losses for 2022 but rebounded with EUR 10 billion in profits in 2023 and EUR 11 billion in 2024. In the Netherlands, consumer price increases lagged by about a year. Although retailers have cut prices by one-third in response to falling wholesale costs, a substantial gap remains, heightening expectations for additional savings to be passed on to consumers.

The second reason for the significant gap between wholesale electricity prices and the energy component of retail rates is that **some countries promptly passed wholesale price increases on to consumers during the energy crisis, and then many utilities in these countries only partially reflected the subsequent wholesale price declines of 2023 and 2024**. In Italy and Spain, the energy component of retail prices closely tracked wholesale trends, eventually reaching similar levels. Italian households paid an average of EUR 200/MWh, even though the wholesale market averaged around EUR 100/MWh. In Spain, the gap was smaller but still historically high. The disparity in Ireland was the largest, with the energy component of retail prices three times higher than wholesale prices.

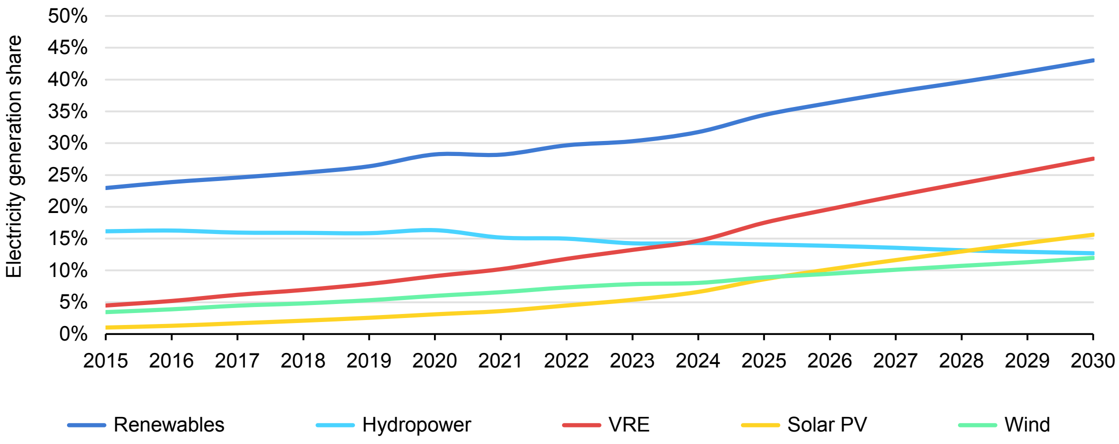
The role of wind and solar PV in power systems

Solar PV and wind contributions raise the renewable energy share in global power supply from one-third to nearly 45% by 2030

The share of renewables in global electricity generation is projected to expand from 32% in 2024 to 43% by 2030, while the share of variable renewable energy (VRE) sources is set to almost double, reaching 28%.

Although hydropower has historically been the dominant renewable energy technology, rapid solar PV and wind growth is shifting the balance. In 2024, the share of generation from all VRE sources surpassed that of hydropower, and by the middle of the forecast period, solar PV alone is projected to overtake it. Furthermore, wind is expected to nearly match it by 2030 – but reaching both milestones will depend on weather conditions.

Global renewable electricity generation shares by technology, 2015-2030



Notes: VRE = variable renewable energy. VRE sources include solar PV and wind.

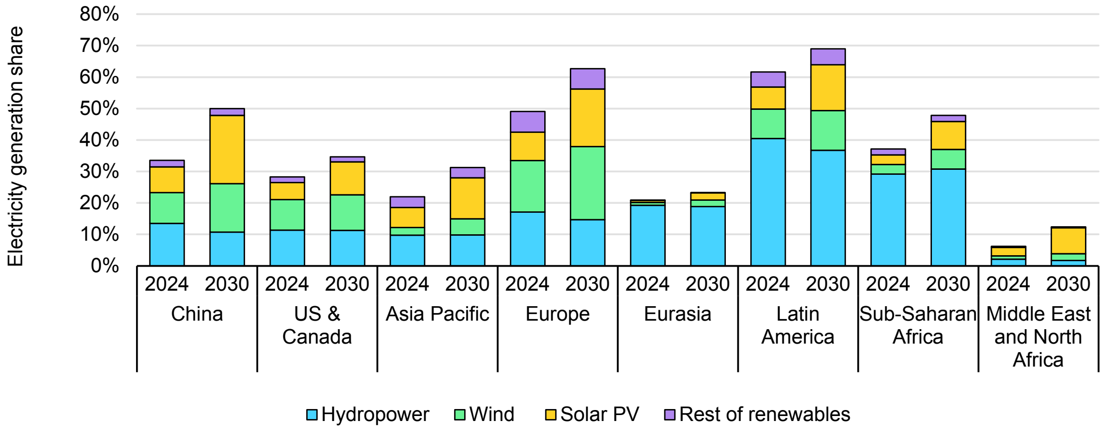
By 2030, nearly half of the electricity generated from solar PV and wind globally will come from China (up from 40% in 2024), with Europe maintaining its position as the second-largest producer. The Asia Pacific region (excluding China) is projected to generate more electricity from solar PV and wind than the United States, securing the third spot globally.

In fact, it is expected that renewable energy will be used to generate 50% of China's power by 2030, with variable renewables contributing 37%. Although hydropower is currently the country's largest source of renewable electricity, providing 13%, solar PV is projected to surpass it by 2026, and wind will overtake it by 2027. Over the forecast period, renewables in China are expected to generate more electricity than coal, which is currently the country's dominant power source. Meanwhile, the share of renewables in the US power mix increases 7% between 2024 and 2030, with solar PV contributing 75% of this growth and wind providing the remainder.

Strong solar PV and wind generation growth is expected in Latin America, with solar PV leading the region's renewable energy expansion – particularly in Brazil, Mexico, and Chile – while hydropower and other sources remain stable. Hydropower is currently the region's dominant energy source, and although its share is declining, it will remain the primary source in 2030. By the end of the decade, solar PV is forecast to generate more electricity than wind, expanding to a 15% share – twice the 2024 level.

In sub-Saharan Africa, solar PV and wind currently each hold a 3% share of power generation, with solar PV expected to grow to 8% and wind to 6% by 2030. Hydropower generation will rise modestly and continue to be the leading renewable energy source, producing about one-third of the region's electricity. South Africa will have the most growth in VRE technologies.

Shares of renewable energy technologies in power generation by region



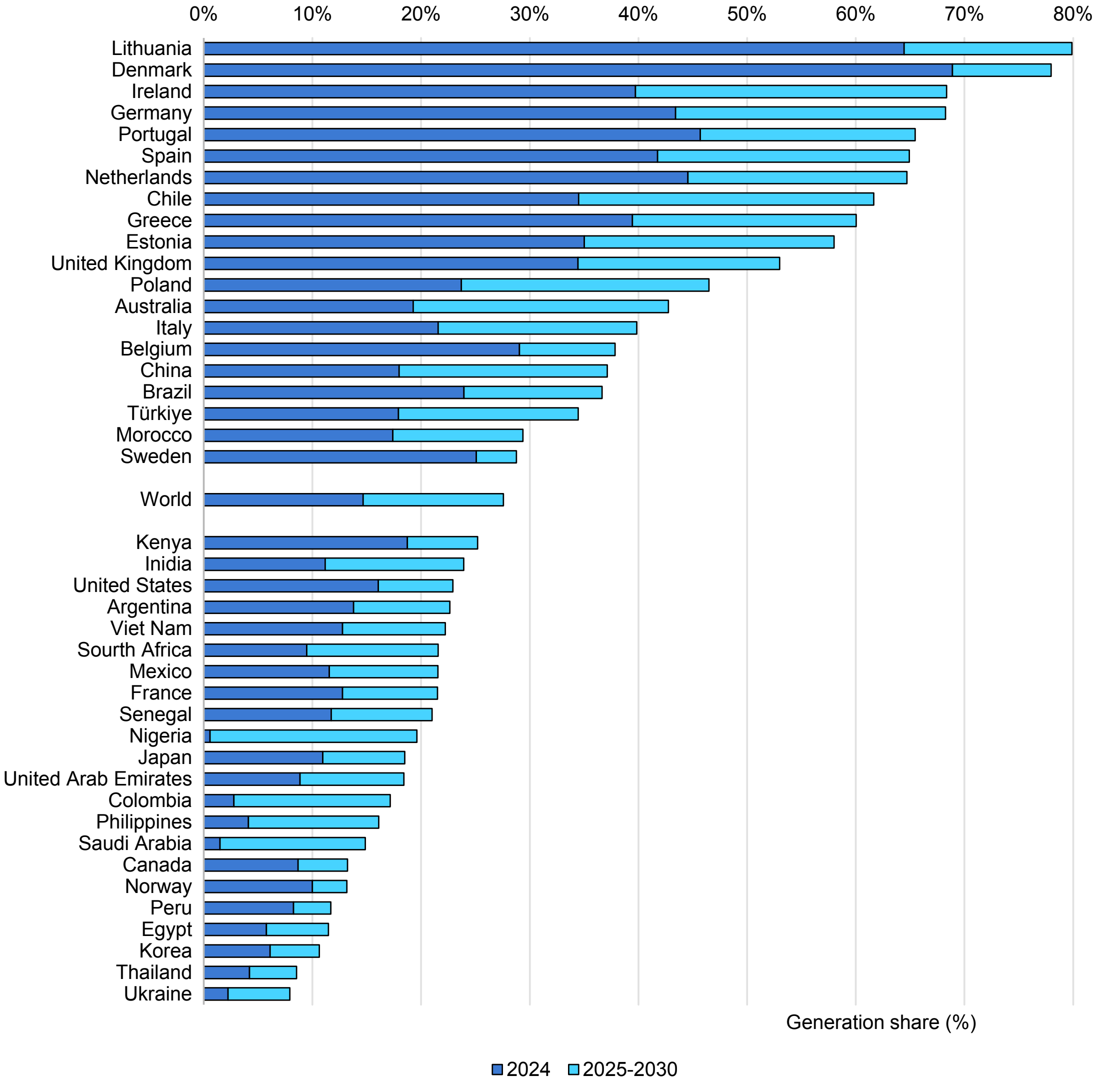
In the Asia Pacific region, the share of renewable energy in the power mix is expected to increase from 22% in 2024 to 32% by 2030. Solar PV growth will be the most substantial, with its generation share doubling and surpassing that of hydropower to become the dominant renewable energy source. India, responsible for over half of the region's renewable energy growth between 2024 and 2030, will play a major role. Moreover, Australia is projected to produce almost 50% of its electricity from solar PV and wind by 2030, the greatest renewable penetration change in the region.

For Europe, which currently has the leading share of VRE power generation globally, wind and solar PV penetration is expected to rise from 25% in 2024 to over 40% by 2030. By the end of the forecast period, both wind and solar PV are individually surpassing hydropower in the generation mix. Germany will record the largest absolute increase in VRE generation, followed by the United Kingdom and Türkiye.

In Germany, VRE sources are set to make up almost 70% of the power mix by 2030. Wind will dominate in the United Kingdom (over 40% of the power mix), while Türkiye is expected to nearly triple its solar PV share. Significant VRE growth is also anticipated in Italy, Poland, the Netherlands, Denmark, Ireland and Lithuania.

In 2024, the average VRE share of the 100 countries analysed was 15%. More than half had shares below 10%, while only 3 generated more than half of their electricity from VRE sources. However, the average is expected to climb to 24% by 2030, with the number of countries below 10% dropping to 27, and those exceeding 50% rising to 14.

VRE generation shares in 2024 and 2030 for selected countries



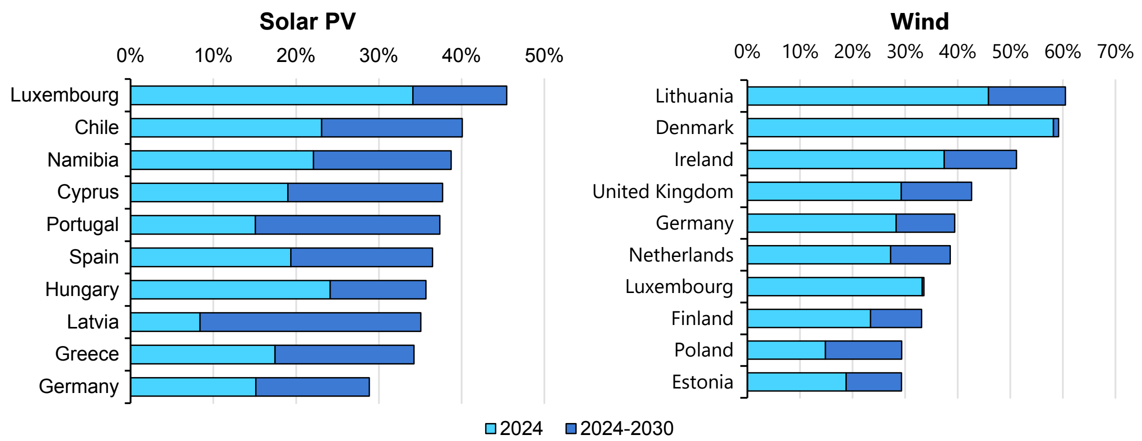
Note: VRE = variable renewable energy.

On average, countries are projected to boost their VRE share by 8 percentage points, though growth will vary. Nearly half will have double-digit increases, led by Latvia (+41 percentage points) and Namibia (+35 points). By 2030, Chile could be generating two-thirds of its electricity from wind and solar PV, and Germany is set to reach 70%. Ireland, Chile and Germany also increase their VRE shares by at least 25 points.

Countries with the highest VRE generation will also experience major growth. China's VRE share could rise from 18% to 37% by 2030, while India is set to more than double its VRE share to 24%, mostly with solar PV. In the United States, solar PV and wind together expand by 7 points, each contributing 11% by 2030.

In 2024, Denmark led VRE penetration at nearly 70%, followed by Luxembourg and Lithuania, both above 60%. By 2030, Lithuania is expected to top the list at 80%, with Luxembourg and Denmark also exceeding 70%.

Top 10 countries by generation share of solar PV and wind by 2030



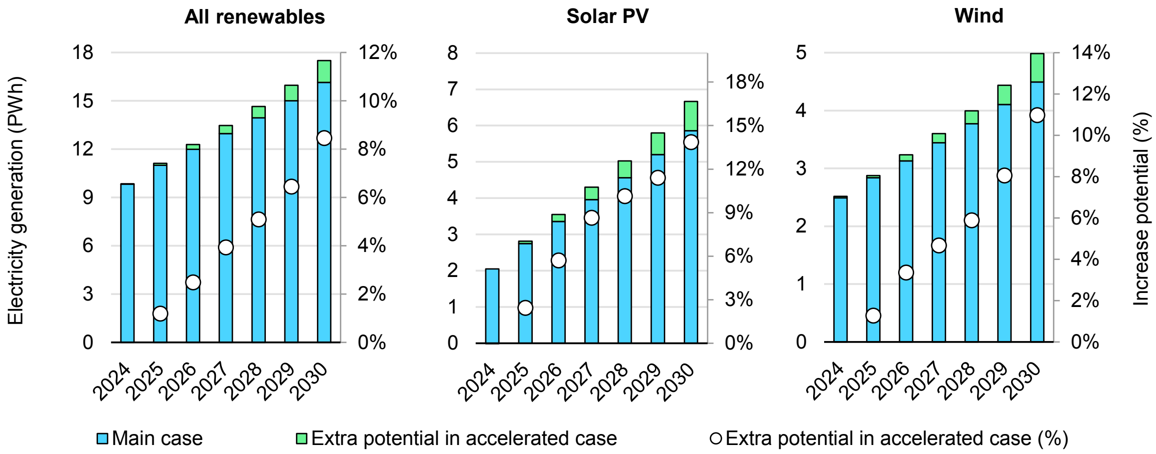
By 2030, Luxembourg is set to have the leading solar PV share in electricity generation, followed by Chile, both above 40%. Several European countries – Portugal, Spain and Greece – will each get at least one-third of their power from solar PV over the forecast period. Germany nearly doubles its solar PV share to about 30%.

Northern European countries have the highest shares of wind power in the electricity mix. Lithuania will become the global leader, with wind accounting for more than 60% of its generation in 2030. Denmark follows closely, with offshore wind set to overtake onshore. Ireland will generate over half of its electricity from wind, while in the United Kingdom, wind (thanks mostly to offshore projects) will supply over 40% by 2030, surpassing natural gas.

Renewable power generation from all technologies and across all regions is projected to increase. However, there is potential for even greater growth if identified challenges are addressed and deployment accelerates.

Our generation estimates are based on projected capacity additions; country- and technology-specific capacity factors; and adjustments for variables such as innovation, curtailment, system flexibility and grid conditions. Taking all these into account, the accelerated case shows an upside potential of 8% more generation by 2030, or nearly 1.5 PWh – equivalent to China's VRE output in 2023.

Global renewable electricity generation, main and accelerated cases



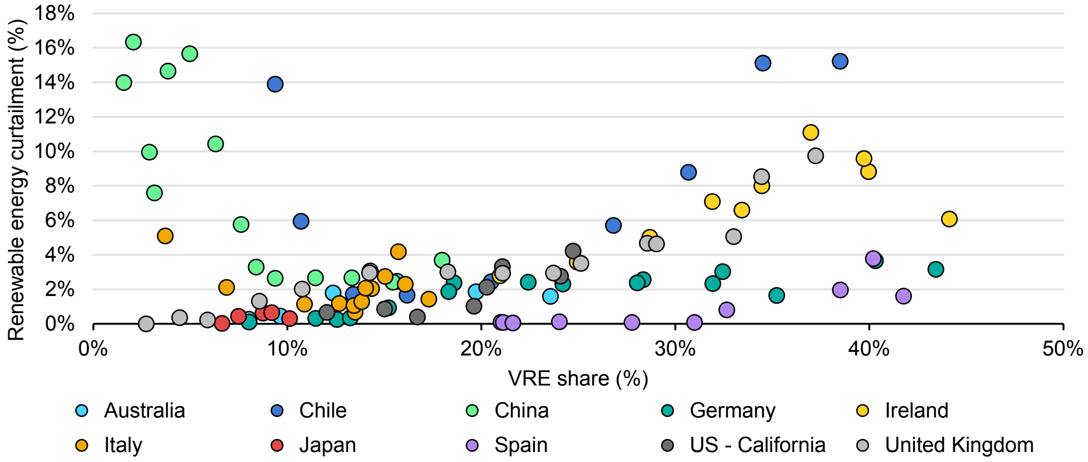
Note: Generation in the accelerated case is calculated based on its capacity forecast, with capacity factors adjusted from the main case. These adjustments account for power system changes such as grid expansion, enhanced flexibility and curtailment management, which can either raise or lower the capacity factor depending on country-specific conditions.

Curtailment is rising with VRE expansion as countries race to deploy measures to increase flexibility and storage

With rapid solar PV and wind expansion, the curtailment of these resources is becoming more common and visible in several markets. Curtailment occurs when the power system cannot absorb all generated power because of transmission capacity limitations, system stability requirements or supply-demand imbalances. While some curtailment is expected and inevitable, persistent or widespread curtailment often highlights gaps in planning, flexibility or infrastructure. Reducing curtailment thus requires a comprehensive strategy involving transmission, flexibility and co-ordinated system planning.

VRE integration is highly dependent on each country's unique situation, including its grid infrastructure and energy policies. Successful integration relies on the adaptation of strategies to local conditions to overcome challenges and optimise renewable energy use.

Annual VRE shares in generation and technical curtailment for selected countries and regions



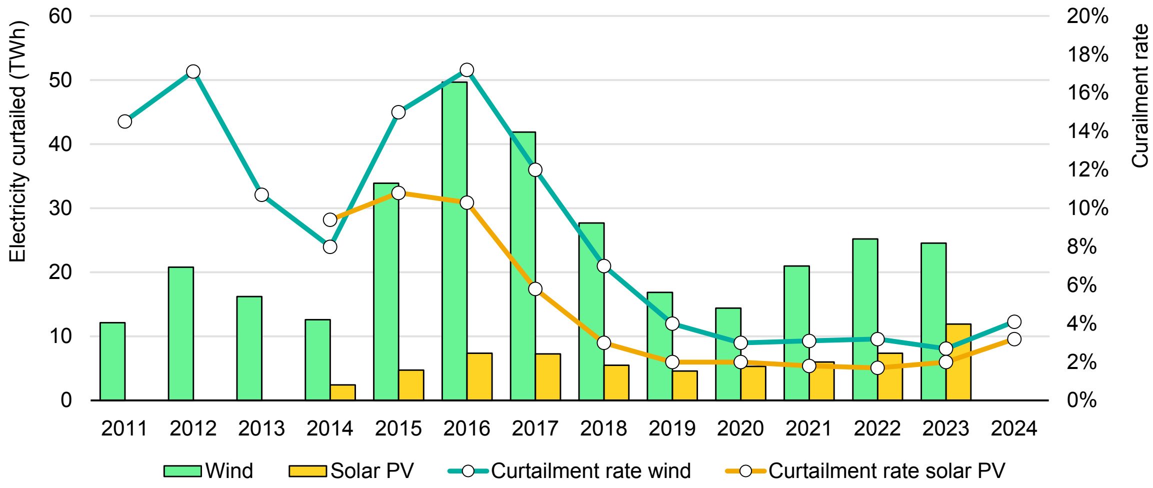
Notes: VRE = variable renewable energy. Each dot represents one year. Data points indicate officially reported curtailed or constrained energy generation and combine various schemes, depending on the country. VRE refers to solar PV and wind unless otherwise specified. The United Kingdom includes wind only. Technical curtailment is the dispatching-down of renewable energy for network or system reasons; dispatched-down energy due to economic or market conditions is not included. The graph covers 2010-2025, but the range varies among countries depending on data availability. The points that refer to 2025 include several months for both curtailment rate and generation share, depending on data availability; this is the case for Chile, Germany, Ireland, Spain and the United Kingdom.

Sources: IEA analysis based on data from Australian Energy Market Operator (AEMO), Quarterly Energy Dynamics (multiple releases); Coordinador Eléctrico Nacional de Chile (CEN), Reducciones de energía eólica y solar en el SEN (multiple releases); National Bureau of Statistics of China (NBS), China Energy Datasheet 2000-2024; Bundesnetzagentur, Monitoring Report 2022; Gestore Servizi Energetici (GSE), Rapporto attivita 2021; EirGrid, Renewable Dispatch-Down (Constraint and Curtailment) reports (multiple releases); Hokkaido Electric Power Network, area supply and demand data (multiple releases); Tohoku Electric Power Network, area supply and demand data (multiple releases); TEPCO Power Grid, area supply and demand data (multiple releases); Chubu Electric Power Grid, area supply and demand data (multiple releases); Hokuriku Electric Power Transmission & Distribution, area supply and demand data (multiple releases); Kansai Transmission and Distribution, area supply and demand data (multiple releases); Chugoku Electric Power Transmission & Distribution, area supply and demand data (multiple releases); Shikoku Electric Power Transmission & Distribution, area supply and demand data (multiple releases); Kyushu Electric Power Transmission and Distribution, area supply and demand data (multiple releases); Okinawa Electric Power, area supply and demand data (multiple releases); Red Eléctrica de España (REE), I3DIA (multiple releases) and Sistema de Información del Operador del Sistema (e·sios); Renewable Energy Foundation (REF), Balancing Mechanism Wind Farm Constraint Payments.

In the early 2010s, China's VRE curtailment reached 15%. To address this, the government set provincial curtailment targets below 5% from 2018 and reformed the feed-in-tariff scheme to encourage project development near demand centres. Average annual grid investments of USD 88 billion and market reforms enabled regional power exchanges. All these measures reduced the annual curtailment rate to less than 3%.

However, in 2024 China raised its wind and solar PV curtailment threshold from 5% to 10% in provinces with high renewable energy penetration to ease grid congestion and support further expansion in areas where strict curtailment limits had previously slowed project approval and development. Despite ongoing UHV transmission expansion, renewables are outpacing grid development in some regions, causing integration issues. That year, curtailment rose to 3.2% for solar PV and 4.1% for wind, an increase of more than one percentage point for each.

Solar PV and wind energy curtailment in China



Sources: National Energy Authority (NEA) and Electric Power and Planning Engineering Institute (EPPEI), accessed through China Energy Transformation Program (2025), Summary of China's Energy and Power Sector Statistics in 2024.

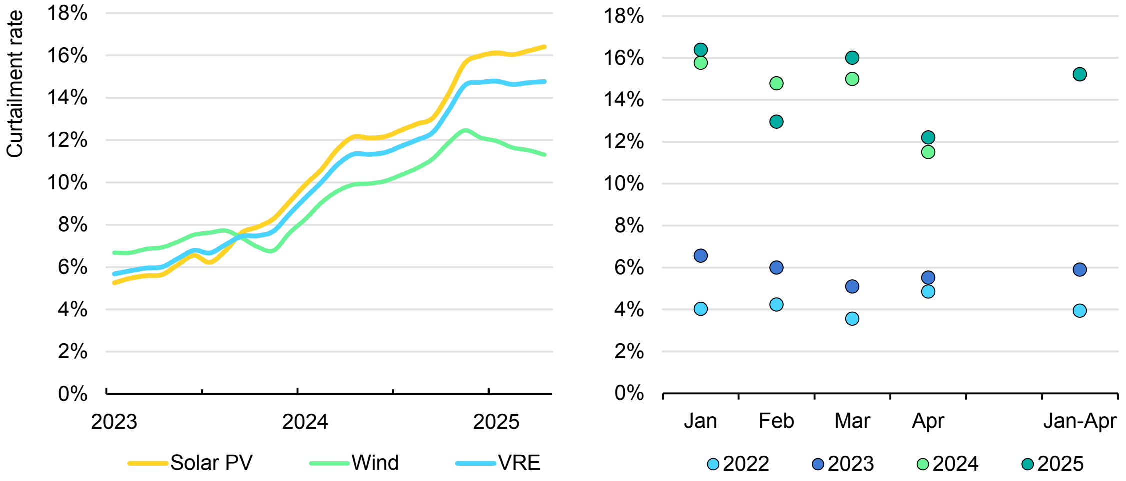
Chile's energy system is still adapting to its speedy VRE expansion of recent years. In 2024, solar PV and wind provided one-third of the country's electricity generation, and this share is expected to almost double by 2030. However, accommodating this rapid growth is challenging, with curtailment increasing swiftly.

Two key factors are contributing to the rise in curtailment. First, the transmission network cannot move the rapidly increasing volumes of renewable energy quickly enough, creating bottlenecks, especially when transferring electricity from the solar- and wind-rich north to demand centres in the central region. Second, solar production surpasses local demand during the midday hours in several areas, leading to energy surpluses the current infrastructure cannot fully utilise or store.

In 2024, 15.1% of wind and solar PV generation was curtailed, marking the highest curtailment rate since 2017, before Chile's two main power systems were integrated. Wind curtailment alone reached 1.5 TWh, equivalent to the country's total wind generation in 2014, when the technology accounted for 2% of the national electricity mix. Solar PV curtailment was even higher at 4.2 TWh – a record 17.2%, exceeding the country's entire solar PV production in 2017.

As Chile enters 2025, variable renewable capacity continues to expand and so do the volumes of curtailed energy. From January to April 2025, the country curtailed almost 2 TWh, equivalent to roughly all VRE generation in 2014. However, this curtailment rate was consistent with the same period in the previous year, showing a potential slowdown in the rising trend. While the absolute volume of curtailed energy increases year over year as capacity and generation expand, the growth rate of curtailment as a percentage appears to be plateauing. The country is currently implementing a grid expansion and storage deployment strategy to mitigate curtailment and enhance VRE integration.

VRE, solar PV and wind curtailment, 12-month moving average (left), and monthly VRE curtailment share for the first trimester of selected years (right) in Chile



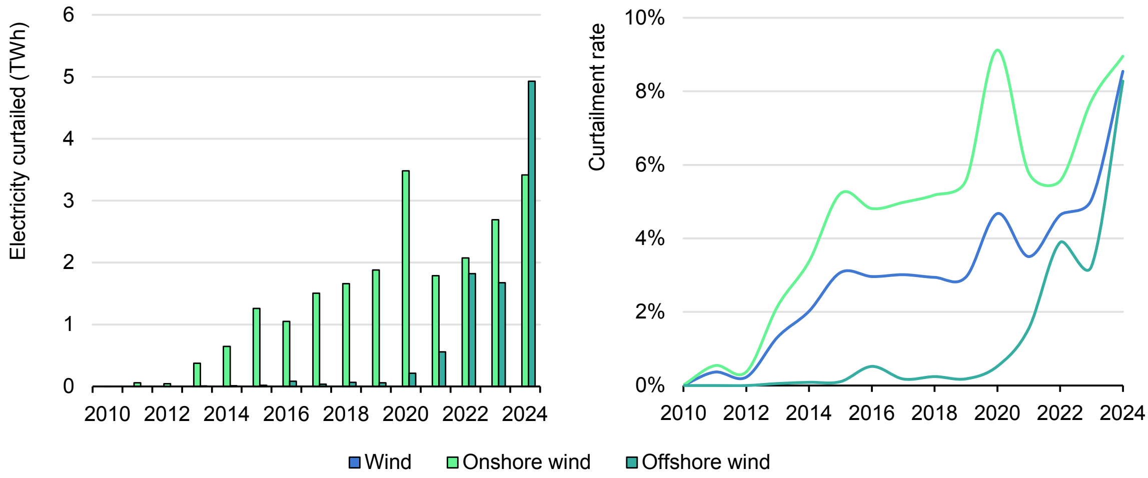
Notes: VRE = variable renewable energy. The 12-month moving average includes the value of that month and the 11 months before.

Sources: Coordinador Eléctrico Nacional de Chile (CEN), Reducciones de energía eólica y solar en el SEN (multiple releases).

The United Kingdom tripled its wind generation share over the past decade, from 9.5% in 2014 to 29% in 2024. While onshore wind generation has grown significantly, the country's main focus has been on offshore wind, which had become the leading renewable electricity source in the energy mix by 2022. However, with most electricity demand concentrated in the southeast and the majority of wind generation located in the north, transmission capacity limitations between Scotland and England have significantly constrained north-to-south power flows, contributing to renewable energy curtailment.

In 2024, 8.5% of wind generation was curtailed – more than the country's total hydropower output that year. Historically, onshore wind in the United Kingdom has had higher curtailment rates than offshore, but in 2024 the gap narrowed significantly. Then, in the first four months of 2025, offshore wind curtailment (11%) surpassed onshore (8%) for the first time.

Electricity curtailed (left) and wind curtailment rates (right) in the United Kingdom



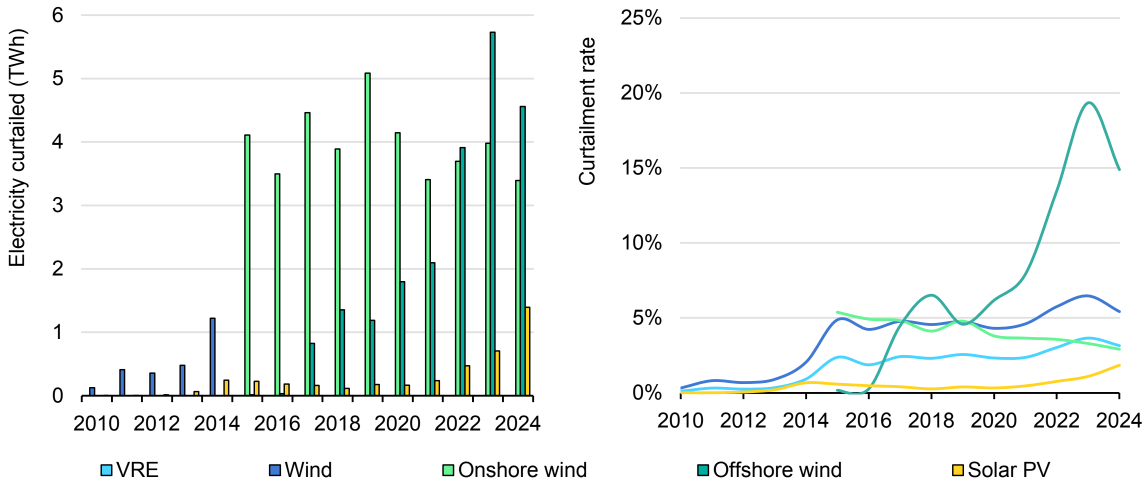
Source: Renewable Energy Foundation (2025), Balancing Mechanism Wind Farm Constraint Payments.

Germany leads Europe in electricity generation from solar PV and wind, producing over one-fifth of the continent's total in 2024. In fact, the country has doubled its VRE generation share since 2017, achieving a 44% in its electricity mix in 2024. More than half of this renewable generation comes from onshore wind, followed by solar PV.

Offshore wind generation in Germany expanded rapidly in the past decade, but lagging grid development led to rising curtailment. By 2023, it had become the most curtailed technology, with nearly one-fifth of output lost. Although curtailment eased slightly in 2024, it remained high. In contrast, onshore wind integration has improved steadily, with curtailment falling below 3% last year.

While Germany is investing heavily in power grid expansion, development delays, especially in the north, are causing grid congestion that is reducing offshore wind farm output. According to Tennet, the absence of large conventional power plants in the area further limits system-balancing capabilities.

Electricity curtailed (left) and VRE curtailment rates (right) in Germany



Notes: VRE = variable renewable energy. The onshore and offshore wind breakdown is available from only 2015 onwards.
Source: Bundesnetzagentur, Monitoring Report (multiple releases).

Renewable power curtailment has economic impacts that extend beyond just lost energy production. It reduces project developer revenues, potentially discouraging future investments, and can also lead to additional costs for countries if they must compensate developers for the curtailed electricity.

Negative prices are surging across multiple countries

Negative electricity prices have become more frequent in recent years, especially in markets that have rising wind and solar PV shares. Negative prices broadly signal insufficient flexibility in the system, resulting from technical, regulatory or contractual constraints. In several countries, such as Germany, Belgium, the Netherlands and France, the number of hours with negative prices has increased significantly. Many of these countries have already experienced as many negative-price hours between January and July 2025 as they did during the entire year of 2024.

Negative prices typically occur between 11:00 and 15:00, coinciding with peak solar generation and lower midday demand. In 2024, 15-20% of all prices between 12:00 and 13:00 were negative in many European markets, including Germany, Belgium, the Netherlands and France, while Spain and Poland had just begun to experience this trend, with negative prices posted for 10% of midday hours. Similarly, countries with a high penetration of wind energy (the United Kingdom and Ireland) often experience negative prices during nighttime hours, when wind output remains high but electricity demand is generally lower.

Frequency and hourly distribution of negative prices by year for selected countries

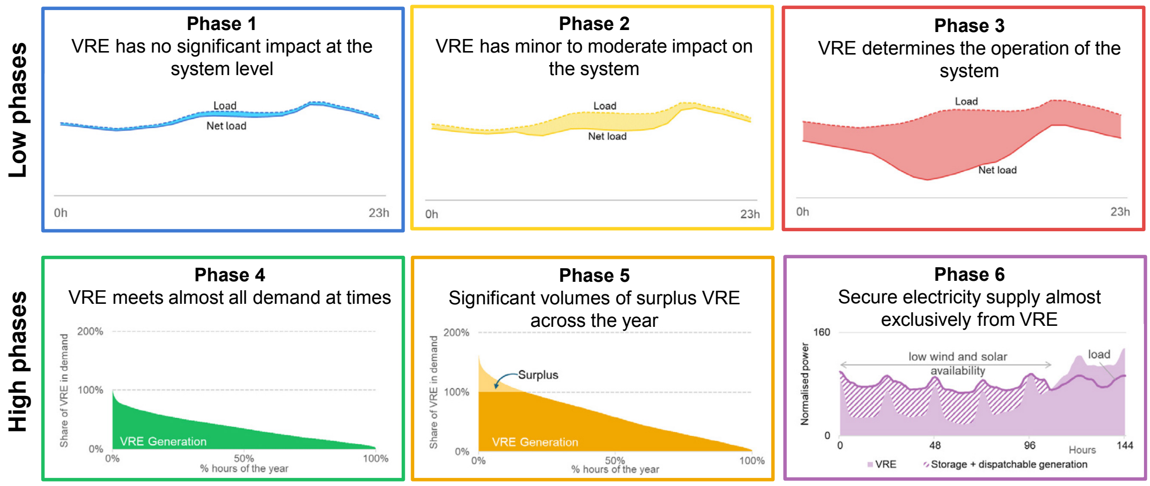
Note: 2025 values are for January to July.

Expanding VRE penetration introduces new power system implications across several countries

The IEA divides VRE integration into six phases that reflect the rising system impacts of expanding solar PV and wind generation, with each phase representing specific challenges and solutions.

Phases 1 through 3 depict the early stages of VRE integration, when solar PV and wind have limited impact on the power system, and the challenges they create can typically be managed through adjustments to existing assets or operational enhancements. In Phases 4 through 6, however, high levels of VRE generation introduce new challenges, including periods of low conventional power, surplus supply during times of low demand and a greater need for flexibility across all time frames. These developments require a fundamental transformation in how power systems are planned, operated and financed.

IEA VRE integration framework phases



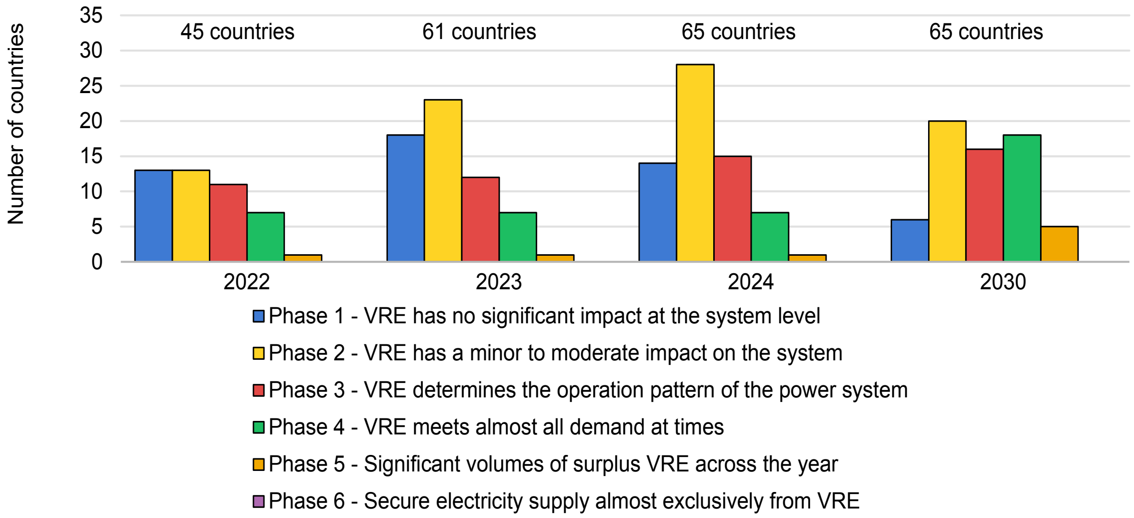
Notes: VRE = variable renewable energy. “VRE” includes solar PV and wind.
Source: IEA (2024), Integrating Solar and Wind.

The IEA regularly analyses VRE integration, and its latest results indicate that, among the 65 countries assessed for 2024, most remain in the lower phases, experiencing only limited power system impacts. In 2022, seven countries were placed at Phase 4, while only Denmark – having the highest share of VRE generation at the time – was assessed at Phase 5.

Based on our current solar PV and wind expansion forecasts, several countries are expected to advance to higher VRE integration phases. Of the 65 countries analysed, 32 are projected to move up to the next phase, reflecting rapid solar PV and wind uptake worldwide. Notably, five countries, including Brazil and Poland, are expected to jump two phases during this period, highlighting their particularly rapid progress in VRE integration. Eight other countries, including Korea, transition from Phase 1 to 2, while 11, including India and China, are expected to move from Phase 2 to 3.

Additionally, 10 countries, including Chile and Lithuania, advance from Phase 3 to 4, marking a shift from the lower to higher VRE integration range. Finally, Germany, Spain and Ireland are the three countries expected to progress from Phase 4 to 5, joining Denmark. Many of these nations will be required to reconfigure their power system planning and operations.

Number of countries in each VRE integration phase, 2022-2024 and 2030



Notes: VRE = variable renewable energy. "VRE" includes solar PV and wind.
Source: IEA (2024), Integrating Solar and Wind.

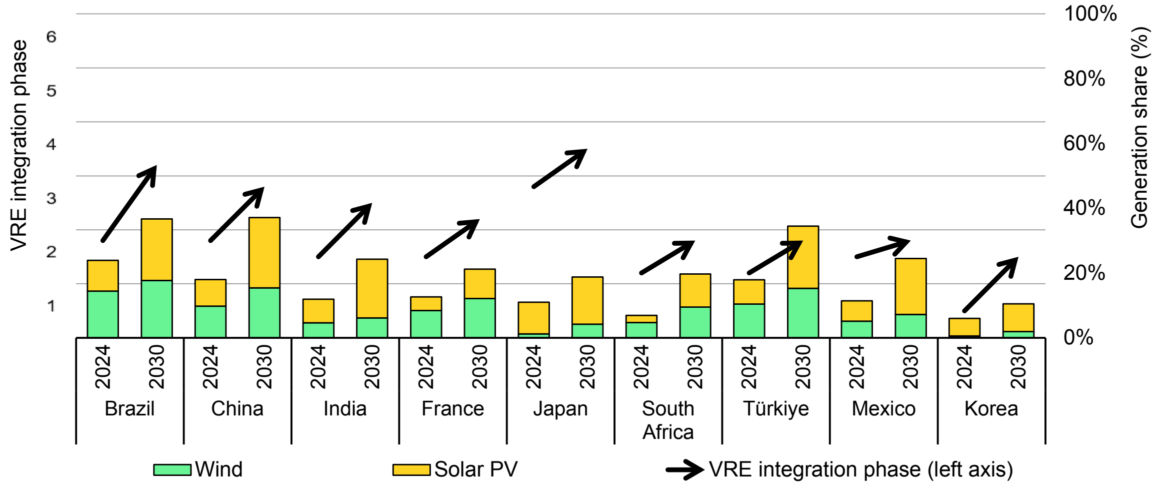
Although the VRE generation share strongly influences the integration phase, an increase in penetration alone does not automatically bump a country to a higher phase. Phase assessments take many other factors into account, including the country-specific generation mix (offshore and onshore wind, and utility-scale and distributed solar PV) and the alignment of load profiles with wind and solar generation. They also consider system flexibility across different timescales and the system's ability to manage disturbances, particularly regarding frequency control and system inertia. For higher phases, assessments additionally examine the timing and extent of VRE surpluses or deficits – periods when generation exceeds or falls short of demand. Other variables (e.g. ramps, changes in load or generation output, behind-the-meter storage and demand-response) also affect phase assignment.

While solar PV generation is generally more predictable than wind power, its midday peak and sharp changes at sunrise and sunset introduce significant ramping and flexibility requirements for power systems. In contrast, wind power tends to be less variable over time and does not typically cause such steep ramps. As a result, countries with solar-dominated VRE deployment often face greater operational challenges than those with similar VRE shares but less solar reliance.

Japan illustrates this point well. Although its 2024 annual VRE share was similar to France's, India's and Mexico's, Japan's system was rated at Phase 3, compared with Phase 2 for the others. This reflects the greater challenge of managing solar variability. Although Japan's net-load ramps are some of the world's steepest, it addresses them through co-ordinated dispatch of flexible generation (mainly from gas, hydro and coal) across nine sub-regional control areas. Despite limited battery storage, its isolated grid shows strong flexibility and effective regional ramp management.

Solar PV and wind power generation is expanding across all regions, including in countries where these resources currently make a relatively small contribution to the power mix. China and India, for example, are expected to double their VRE shares between 2024 and 2030, moving from Phase 2 to Phase 3. South Africa, Türkiye and Mexico are also projected to at least double their VRE shares over the same period, yet their assessments indicate they will remain in Phase 2. Meanwhile, solar PV development in Brazil is set to push it from Phase 2 to 4 by 2030, marking it as one of the few countries experiencing a two-phase jump.

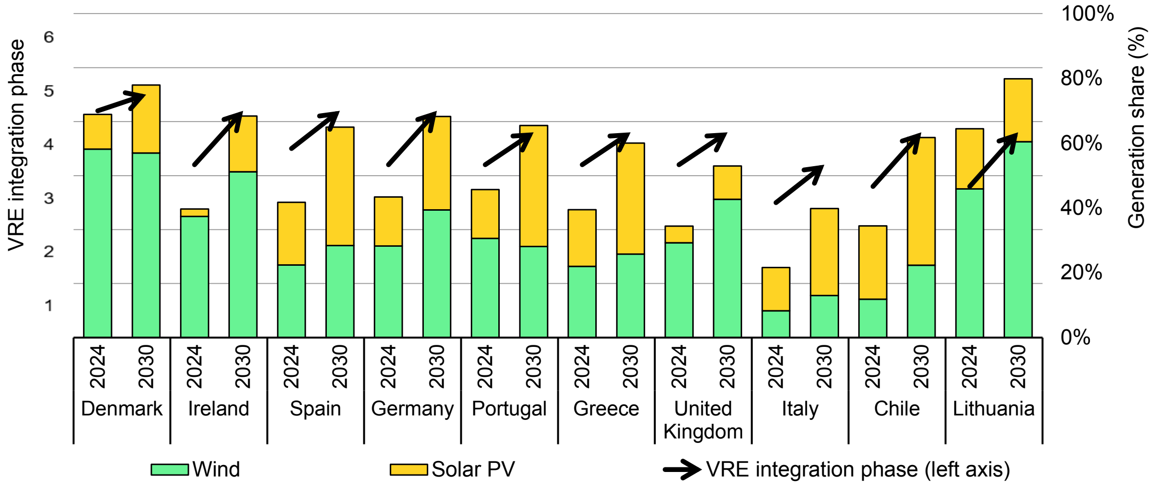
VRE integration phase and solar PV and wind generation shares for selected countries, 2024 and 2030



Note: VRE = variable renewable energy.
Source: IEA (2024), Integrating Solar and Wind.

Phase 4 is characterised by high instantaneous VRE penetration, which creates short-term operational challenges (<15 min), particularly with respect to system inertia and stability. In 2024, countries such as Ireland, Germany and the United Kingdom were at this stage, with others (e.g. Lithuania, Chile and Italy) expected to follow by 2030.

VRE integration phase and solar PV and wind generation shares for selected countries, 2024 and 2030



IEA. CC BY 4.0.

Note: VRE = variable renewable energy.
Source: IEA (2024), Integrating Solar and Wind.

In Phase 5, short-term issues are overtaken by longer-term challenges arising from prolonged periods of VRE surpluses and deficits. These imbalances can occur across hourly, daily, seasonal and even interannual timescales. If not properly managed, they may result in high curtailment and reduced system efficiency. Addressing these challenges requires flexibility resources capable of sustaining responses over weeks or months, with interconnection and long-term storage being key solutions. In 2024, only Denmark had reached this phase, but countries such as Ireland, Spain and Germany are expected to transition to it by 2030.

Chapter 2. Renewable transport

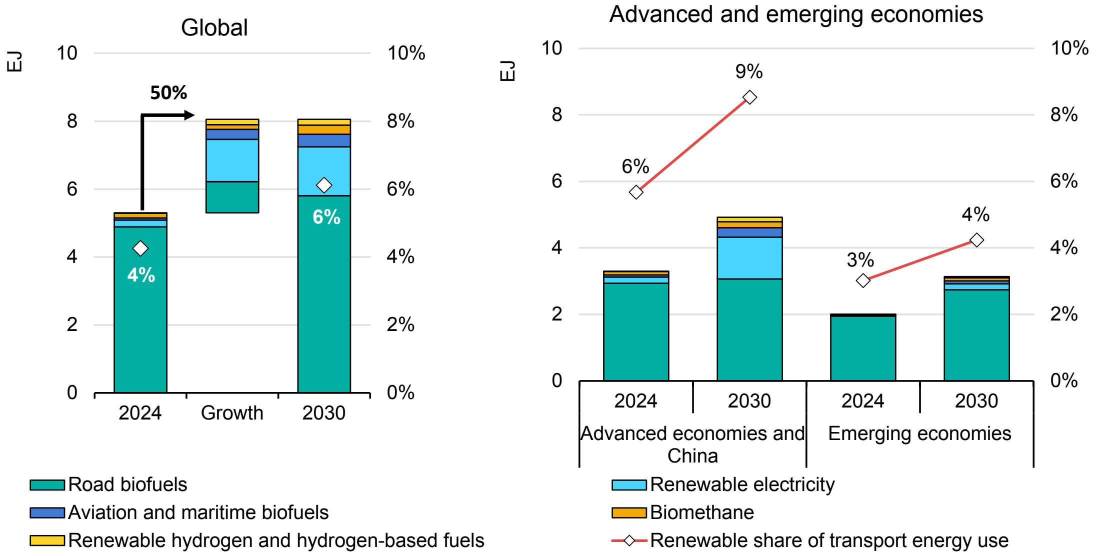
Global forecast summary

Renewable energy in transport is set to expand 50% to 2030

With greater use of renewable electricity, liquid biofuels, biogases and renewable hydrogen and hydrogen-based fuels, renewable energy consumption in transport is expected to rise 50% by 2030. The largest share of this growth (45%) will come from renewable electricity used for electric vehicles, especially in China and Europe.

Road biofuels contribute the second-largest share (35%), with significant growth in Brazil, Indonesia, India and Malaysia, supported by tightening mandates and rising fuel demand. Aviation and maritime fuel use makes up 10% of growth, primarily owing to mandates in Europe, and the remaining 10% comes from biomethane, renewable hydrogen and hydrogen-based fuels, with activity concentrated in the United States and Europe.

Renewable energy shares in transport in selected economies, main case, 2024-2030



Notes: Renewable electricity estimates are based on the renewable electricity forecast and EV energy use in the Global EV Outlook. The energy share of transport demand is based on total global transport energy demand in the World Energy Outlook STEPS scenario.
Sources: IEA (2025), Global EV Outlook 2025; IEA (2024), World Energy Outlook 2024.

Globally, EVs are expected to account for more than 15% of the vehicle stock by 2030, with renewable electricity meeting more than half of electricity demand in key markets. In China, EVs represent more than one-third of cars on the road by 2030 as vehicle costs decline and charging infrastructure continues to be enhanced. At the same time, renewable electricity is expected to make up over half of China's total power generation.

The availability of more affordable Chinese EVs is also driving higher adoption in emerging economies, where sales are projected to rise 60% in 2025 alone. Nevertheless, total renewable electricity use in transport is near 15% lower than in last year's forecast, primarily because the elimination of EV tax credits in the United States is expected to reduce US EV sales by more than half by 2030.

Biomethane use in transport increases 0.14 EJ by 2030, a 6% downward revision from last year's forecast. The largest growth is in Europe (0.07 EJ), where biomethane is attractive for its low GHG intensity and eligibility to count towards sub-targets to help member states meet EU-wide Renewable Energy Directive transport sector targets. In the United States, transport biomethane use expands 0.04 EJ, supported by California's Low Carbon Fuel Standard (LCFS), the Renewable Fuel Standard (RFS) and federal production incentives. However, growth is slower over the forecast period than in the last five years because the existing natural gas vehicle fleet is approaching the biomethane saturation point. Smaller increases are also expected in India (0.01 EJ) and China (0.01 EJ).

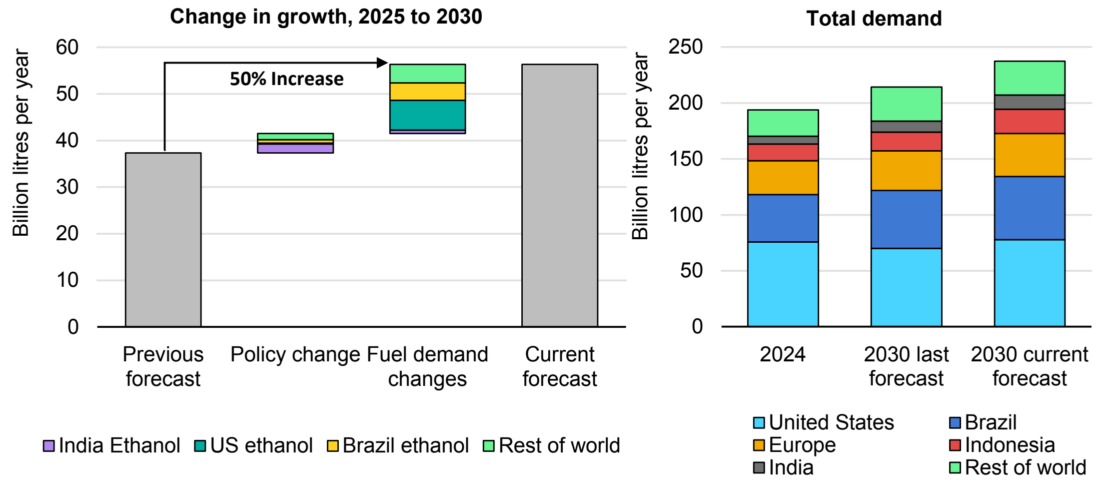
The forecast for the use of low-emissions hydrogen and hydrogen-based fuels remains similar to last year. However, we have revised down the e-fuel forecast because there have been no final investment decisions (FIDs) for e-kerosene projects in the European Union to meet 2030 ReFuelEU Aviation targets.

Nevertheless, low-emissions hydrogen and hydrogen-based fuels use increases from near zero in 2024 to 0.17 EJ by 2030. Demand for hydrogen-based fuels is driven almost entirely by ReFuelEU Aviation targets and Germany's mandate for renewable fuels of non-biological origin in the aviation sector. Direct use of hydrogen in transport remains concentrated in a few countries that continue to support hydrogen vehicle demonstration programmes (e.g. the United States, China, Japan and Korea).

Biofuel growth to 2030 is revised 50% upwards

In the United States, lower EV sales and recent changes to Corporate Average Fuel Economy standards that reduce overall fleet efficiency have prompted us to increase our transport fuel demand forecast from last year. Gasoline and diesel demand in Brazil and Indonesia are also expected to climb more quickly than was previously projected, raising ethanol and biodiesel demand at fixed blending rates. As a result, we have revised projected demand growth for liquid biofuels upwards by 50% through 2030. Policy changes – including increased biodiesel blending mandates in Indonesia, and Spain's proposed transport GHG intensity target – contribute to higher demand.

Forecast revisions to biofuel demand growth and total demand, main case, 2024-2030



Notes: Policy and fuel demand changes were estimated based on the IEA Oil 2024 forecast and policy changes to mid-July 2025. Fuel demand changes cover biofuel demand resulting from transport fuel demand differences between the IEA Oil 2025 forecast and the IEA Oil 2024 forecast.

The United States remains the largest biofuel producer and consumer to 2030, followed by Brazil, Europe, Indonesia and India. In this year's forecast, US biofuel demand is slightly (3%) above the 2024 level in 2030, while last's year's forecast anticipated a 5% decline. In contrast, biofuel demand jumps 30% (0.35 EJ) in Brazil, 30% (0.27 EJ) in Europe, 50% (0.23 EJ) in Indonesia and 80% (0.12 EJ) in India. All regions are strengthening their mandates and GHG intensity regulations during the forecast period. In the rest of the world, growth is led by Canada (+0.06 EJ) and Thailand (+0.05 EJ).

Biofuel producers continue to face economic challenges in 2025

While the 2030 forecast for biofuels remains positive, several producers – especially of biodiesel, renewable diesel and sustainable aviation fuel (SAF) – continued to experience tight to negative margins in 2025. We forecast a 20% drop in biodiesel and renewable diesel use in 2025 (from 2024) in the United States and production down nearly 15%. In the United States and Canada, several plants have been idled or had their output reduced because of policy uncertainty, low credit values and higher feedstock costs.

Output in the United States fell sharply, with drops of 40% for biodiesel and 12% for renewable diesel from Q1 2024 to Q1 2025. Renewable Identification Number (RIN) values under the US RFS were down more than 50% from 2023 throughout 2024 and early 2025, while California's LCFS credits remained depressed. Combined with flat/rising feedstock prices, this significantly eroded profitability for producers, and uncertainty surrounding tax credits, changes to the RFS and final implementation details for the new 45Z tax credit further dampened producer enthusiasm in early 2025.

However, RFS credit prices have rebounded in recent months, and we expect that extensions to the 45Z tax credit (as finalised in the One Big Beautiful Bill Act [OBBBA]), increased RFS volume obligations, and California's plans to strengthen LCFS targets will maintain demand signals over the forecast period. Nevertheless, current and proposed changes affecting domestic biofuels and feedstocks may raise feedstock costs, putting continued pressure on margins. Uncertainty remains considerable, as the final RFS rules and additional details on the 45Z tax credit had not yet been published as of October 2025.

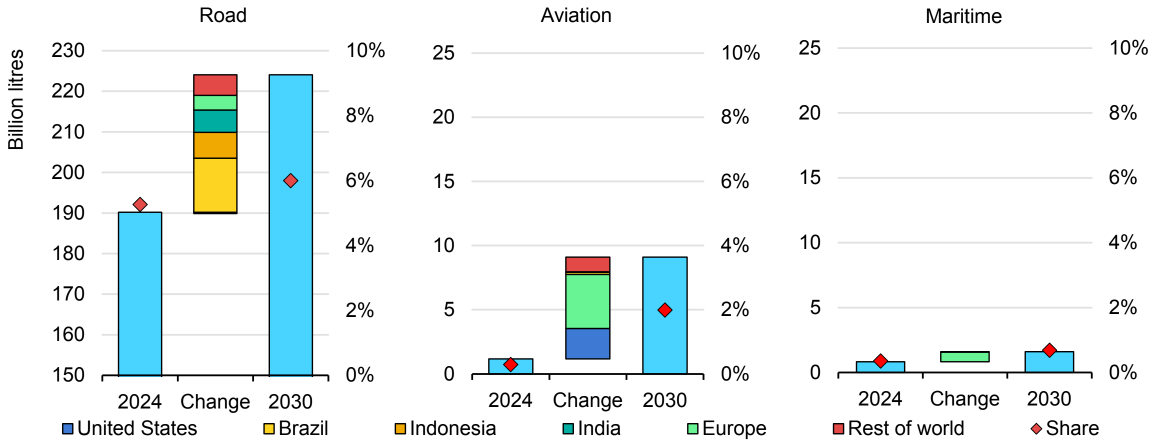
New trade developments are also influencing producer decisions. In May 2025, the United Kingdom signed a revised trade agreement with the United States, reducing duties on US ethanol for the first 1.4 billion litres of imports. In August 2025 Vivergo fuels announced that it had ceased production and commenced closing procedures.

Road sector consumption remains the main source of growth, but aviation and maritime fuels are also gaining ground

Biofuel demand rises 43 billion litres (1.2 EJ) by 2030, reaching 8% of total transport fuel demand on a volumetric basis. Around 80% of this growth occurs in the road sector as Brazil, Indonesia and India expand their mandates and transport fuel consumption increases. In Canada and across Europe, tightening mandates and GHG intensity requirements drive much of the remaining growth. The United States continues to be the largest road biofuel producer and consumer through 2030, though overall volumes remain flat as declining ethanol and biodiesel use offset rising renewable diesel consumption.

In the aviation sector, biofuel use rises to 9 billion litres (0.3 EJ) per year by 2030, covering 2% of total aviation fuel demand. Most growth is stimulated by the EU ReFuelEU Aviation mandate of 6% SAF use by 2030, and the UK target of 10%. Despite a 40% reduction in SAF tax credit value under the OBBBA, SAF demand in the United States is still expected to increase, supported by the combination of LCFS credits, RFS incentives, state level support, remaining tax credits and voluntary purchases by airlines. Additional demand growth comes from SAF programmes in Japan, Korea and Brazil.

Biofuel demand by transport subsector, main case, 2024-2030



Note: Volume shares are based on the IEA Oil 2025 report.
Source: IEA (2025), Oil 2025.

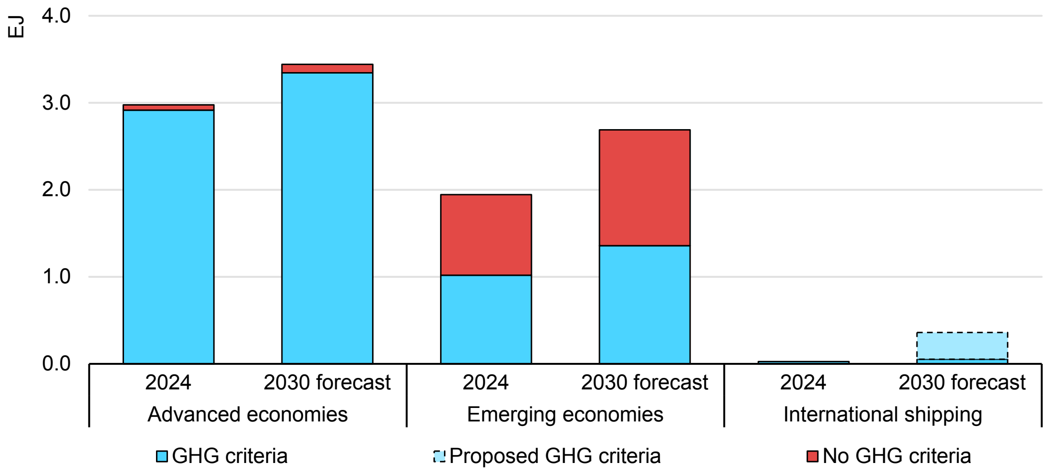
In maritime transport, biodiesel demand grows to 1.6 billion litres (0.05 EJ) by 2030, making up 0.7% of total maritime fuel consumption. Nearly all demand is linked to the FuelEU Maritime regulation, which requires a 2% reduction in GHG intensity by 2025 and 6% by 2030. The proposed International Maritime Organization (IMO) Net-Zero Framework is excluded from the main case, as final approval and detailed implementation rules are still pending. It is, however, considered in the accelerated case and discussed in a dedicated section.

Emerging economies can benefit from implementing GHG performance frameworks

Performance-based standards and GHG thresholds now cover 80% of global biofuel demand, with near-universal coverage in advanced economies. In a smaller group of countries, performance-based standards serve as a primary driver of biofuel deployment. These policies – designed to reward GHG intensity reductions – supported 20% of global biofuel demand in 2024 and are projected to underpin nearly one-third by 2030.

The United States, Canada, Germany and Sweden rely on performance-based frameworks as their main policy tool to expand low-carbon fuel use. France, Spain, the Netherlands and Romania plan to implement similar systems by 2030, and the IMO has announced a global fuel standard for international shipping starting in 2028. In contrast, GHG thresholds or performance-based mechanisms cover only half of biofuel demand in emerging economies. Brazil is the only emerging economy with a dedicated performance-based policy in force, through its RenovaBio programme.

Liquid biofuel demand covered by GHG criteria, 2024 and 2030



Notes: "GHG criteria" includes performance-based GHG intensity targets, incentives and GHG thresholds. "Proposed GHG criteria" includes the IMO's proposed global fuel standard.

Most emerging-economy support for biofuels consists of blending mandates or technology-specific incentives. Nonetheless, producers in countries such as Indonesia, Malaysia and India increasingly certify their fuels through international schemes such as the International Sustainability and Carbon Certification (ISCC) initiative or the Roundtable on Sustainable Biomaterials (RSB) programme to meet export requirements. In Indonesia and Malaysia, certification is common for fuels entering the European market or for use in aviation under the Carbon Offsetting and Reduction Scheme for International Aviation (CORSIA). India has also stated its ambition to become a major exporter of sustainable aviation and maritime fuels, with several SAF projects under development and a national certification framework in progress for maritime fuels.

However, reliance on external certification alone may not be sufficient to scale up deployment or ensure reliable market access. As global fuel markets (especially aviation and maritime) shift towards carbon-based eligibility rules, countries without recognised domestic GHG thresholds may struggle to demonstrate compliance. Introducing national GHG ceilings can strengthen policy credibility, enable the rollout of credit systems and reinforce alignment with international frameworks. For countries aiming to expand exports and attract investment, these tools provide a transparent signal of emissions performance and can reinforce the validity of using biofuels as a decarbonisation strategy. Moreover, existing mandates and incentive programmes can be readily modified by drawing on best practices from jurisdictions that have already implemented thresholds and performance-based approaches.

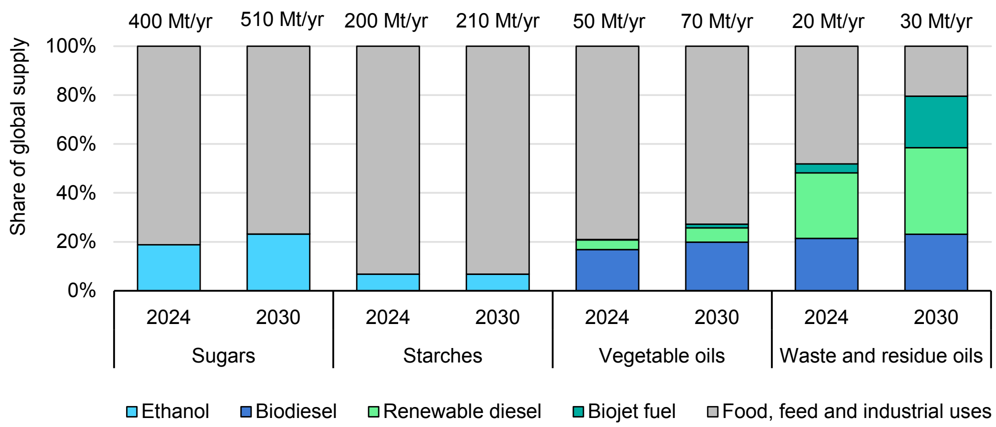
Vegetable, waste and residue oils are in high demand to support biofuel growth

Biofuel feedstock demand climbs to nearly 825 Mt per year in 2030 – up 25% from 2024. Demand for vegetable oils, primarily soybean, palm and rapeseed oil is forecast to expand by nearly 20 Mt/yr, and waste and residue oils by 10 Mt/yr to support biodiesel, renewable diesel and biojet fuel use. Demand for these feedstocks is rising at a faster rate than global supplies are expanding, with biofuels forecast to claim 27% of global vegetable oil production by 2030 (up from just under 21% in 2024) and 80% of estimated waste and residue oil supply potential (from just near 50% in 2024).

Vegetable oil demand expands the most in Brazil, Indonesia and Malaysia to comply with higher blending mandates and increased fuel demand. The United States is also forecast to use more vegetable oils following tax credit and proposed RFS changes that favour domestic vegetable oil use.

Waste and residue oils are highly sought after because they offer low GHG intensities, double-count towards mandates in many EU countries and meet biojet feedstock restrictions in the European Union. However, demand for these feedstocks has led to several issues, including an increase in imports; concerns over dumping and fraud; and price variability, which is wreaking havoc with credit markets and producer margins. In response, oversight has increased in both the United States and the European Union.

Liquid biofuel feedstock demand and shares of global supply, main case, 2024 and 2030



Sources: OECD/FAO (2024), OECD-FAO Agricultural Outlook 2024-2033; World Economic Forum (2020), Clean Skies for Tomorrow: Sustainable Aviation Fuels as a Pathway to Net-Zero Aviation.

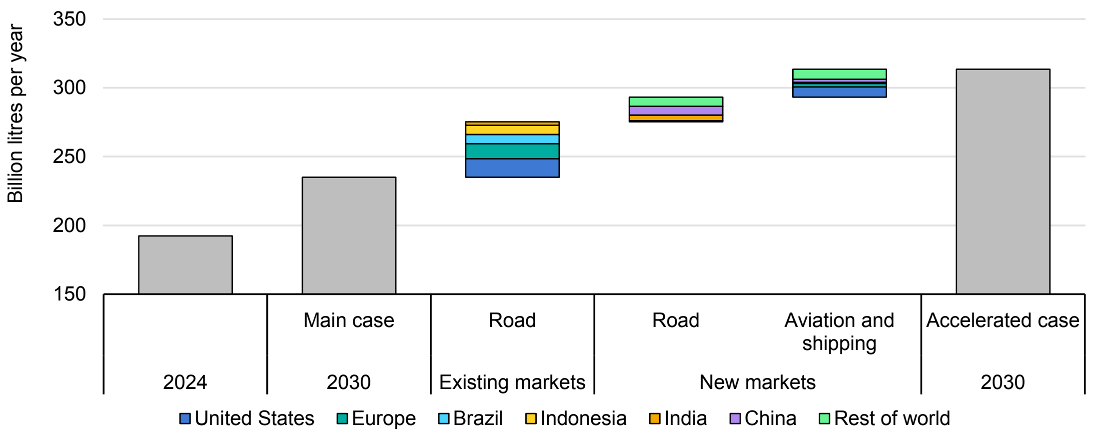
The European Union has launched a Union Database for Biofuels to enhance traceability and prevent fraud, while ISCC strengthened its audit rules and suspended over 130 certifications. In the United States, California will require sustainability certification under its revised LCFS, and federal proposals reduce credit values for imported feedstocks. The OBBBA further restricts tax credits for imported fuels and fuels made from imported feedstocks, with exceptions for Canada and Mexico.

While demand for sugars and starches to support ethanol production increases 130 Mt/yr to 2030, shares of global production increase only slightly, because of overall growth in sugarcane and starch production. Demand for these feedstocks rises the most in Brazil and India to meet to expanding ethanol mandates and fuel demand.

Biofuel demand could be 30% higher if announced policies are implemented by 2030

In the accelerated case, global biofuel demand reaches 310 billion litres per year (8.5 EJ) by 2030 – an increase of 30% relative to the main case – driven by the full implementation of policies already announced or under development. Almost half of this additional demand would come from the strengthening of existing road transport policies: the greater use of higher-ethanol blends in the United States; full transposition of RED III transport targets across the European Union; and the expansion of blending mandates in Brazil, Indonesia and India.

Liquid biofuel demand, main and accelerated cases, 2024 and 2030



Notes: "Existing markets" includes countries or regions where specific biofuels are already in use and supported by policy frameworks, supply chains and infrastructure (e.g. ethanol in India and renewable diesel in the United States). "New markets" includes countries or regions where specific biofuels are not widely used and do not have supportive policy frameworks, supply chains or infrastructure in place (e.g. ethanol in Indonesia, and biofuels in the maritime sector).

The other half of this growth would stem from biofuels entering new market segments, for instance through India's biodiesel blending targets, the implementation of planned SAF mandates in multiple countries, the IMO's forthcoming global fuel standard, and modest biofuel blending in China.

However, realising this growth will require more than demand signals. Achieving the accelerated trajectory would necessitate an additional 125 million tonnes of feedstock supplies, but vegetable, waste and residue fats, oils and greases are already under particularly high demand for biodiesel, renewable diesel and biojet fuel production. To meet sustainability requirements and diversify the feedstock base, feedstock strategies will need to emphasise land-efficient practices such as yield optimisation, intercropping, sequential cropping, and cultivation of marginal or degraded land.

Furthermore, with the support of grants, concessional financing, guaranteed pricing and targeted blending mandates, it will also be essential to scale up the use of emerging technologies that rely on more diverse or abundant feedstocks (cellulosic ethanol and Fischer-Tropsch renewable diesel and biojet fuels are potential pathways, especially post 2030). Even for mature technologies, financial derisking remains critical to support investments in new geographies and sectors.

Performance-based standards can further ease feedstock constraints by maximising the GHG reduction per litre of biofuel. For instance, a 20% improvement in the average GHG intensity of fuels in the European Union would lead to a 25% reduction in the fuel volume required to meet its transport sector target.

Road

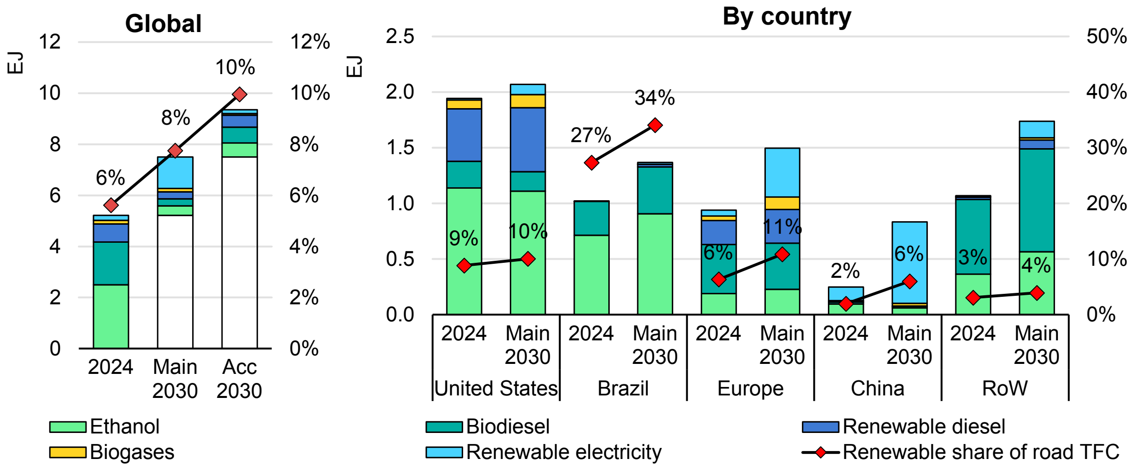
Forecast

Renewable energy demand for road transport is projected to rise 2.3 EJ, reaching 8% of total road subsector energy use by 2030. Renewable electricity consumption for electric vehicles accounts for more than half of this growth, concentrated mainly in China and Europe as renewable electricity generation increases and electric vehicle fleets expand.

Liquid biofuels make up most of the remainder, with biofuel demand growth concentrated in Brazil (40%), Indonesia (20%), India (15%), Europe (10%) and Canada (7%), where biofuel support policies become more stringent over the forecast period. Total biofuel demand in 2030 has been revised 10% upwards from our last forecast, largely reflecting increased transport fuel demand in the United States, Brazil, Indonesia and India (see the Global Forecast Summary above).

The use of biogases also expands, primarily in Europe as EU member states work to meet their transport targets. In the accelerated case, renewable fuel use in transport could reach 9.4 EJ, or 10% of total road transport demand. However, achieving this would require full implementation of planned policies, diversification of biofuel feedstocks and the deployment of advanced production technologies.

Renewable road transport forecast, main and accelerated cases, 2024 and 2030



Notes: RoW = rest of world. TFC = total final consumption. Renewable electricity use is based on renewable electricity shares for each region, consistent with this report's forecast and total electricity demand for plug-in hybrids and battery electric vehicles. Road TFC includes gasoline, diesel, natural gas, ethanol, biodiesel, renewable diesel, biogases and electricity.
Source: IEA (forthcoming), World Energy Outlook 2025.

In the **United States**, renewable energy use in transport is expected to climb nearly 0.13 EJ to 10% of total transport energy demand by 2030. Renewable electricity and biogas account for nearly all growth. The IEA has lowered its outlook for electric car sale shares in the United States from 50% by 2030 to 20% to account for US policy changes that aim to remove subsidies as well as other measures that favour EVs. Nevertheless, renewable electricity use for EVs is projected to increase by near 0.1 EJ to 2030.

Meanwhile, biofuel demand is expected to remain steady, up from a slight decline in last year's forecast. This change stems largely from increased ethanol use, resulting from lower EV adoption and revised vehicle efficiency standards that raise gasoline demand 15% in 2030 compared with last year's forecast. Ethanol blending increases accordingly. Federal RFS obligations have been boosted 8% for 2026-2027, while California raised its GHG reduction target from 20% to 30% by 2030. These changes have little effect on the biodiesel and renewable diesel demand forecast to 2030, however, as consumption in 2024 was already well above mandated levels (see US focus section below). Biogas use in transport also expands, benefiting from the LCFS and the RFS.

Brazil's renewable energy demand for transport is projected to increase 0.36 EJ to 34% of total road transport consumption by 2030, driven almost entirely by the Fuel of the Future law's ethanol and biodiesel blending targets, and by rising fuel demand. In June 2025, Brazil raised its ethanol blending cap by 2.5 percentage points to 30%, effective August 2025. However, widespread flex-fuel vehicle use enables actual blending rates to exceed the mandate.

Biodiesel blending is capped at 20% by 2030, and the main case assumes Brazil reaches 17% by that year, with approved 15% blending taking effect in August 2025. Liquid fuel demand is expected to increase 10% between 2024 and 2030 despite expanding electric vehicles sales.

In **Europe**, renewable energy demand for road transport increases 0.5 EJ to 11% of total subsector fuel demand. Renewable electricity accounts for more than half of this expansion, as manufacturers are beginning to introduce more competitively priced electric vehicles to comply with the new phase of the EU CO_2 emissions standards that entered into force in 2025.

The IEA estimates that, thanks partly to CO_2 standards for light-, medium- and heavy-duty vehicles and buses, electric vehicles will make up 15% of the light-duty vehicle stock and 5% of trucks by 2030. With renewable electricity shares expected to reach 62%, this means a considerable increase in renewable electricity use for transport by 2030.

Biofuel demand grows by 3.2 billion litres (0.1 EJ) by 2030, broadly consistent with last year's forecast. Renewable diesel accounts for 70% of this growth and ethanol for the remainder, while biodiesel use declines 6%. Germany leads the increase, owing to its 25% GHG intensity reduction target. Spain's growth is the second largest, with biofuel demand nearly doubling to 3.8 billion litres. The forecast assumes Spain partially meets its proposed 15.6% GHG reduction target by 2030 since its final rule has yet to be released. Ethanol, biodiesel and renewable diesel use expand to meet the targets, with ethanol buoyed by an ongoing shift to gasoline and gasoline-hybrid vehicles. RED III transposition and its broader implications are discussed in the Policy Trends section below.

Meanwhile, the renewable energy share in **China**'s transport sector demand climbs to 6% from just 2% today, owing almost entirely to growth in renewable electricity use. In China, EVs are projected to represent more than one-third of cars on the road by 2030 as vehicle costs decline and the government supports ongoing enhancements to charging infrastructure. Renewable electricity is also expected to expand from just under one-third of generation today to more than half of total electricity generation by 2030.

There remains little support for biofuel use in China beyond city and regional ethanol and biodiesel blending targets. We therefore forecast no growth in the combined use of liquid and gaseous biofuels in the transport sector to 2030.

In the rest of the world, renewable energy consumption expands 0.7 EJ to make up 4% of total transport energy use. Biofuels account for more than three-quarters of this growth and renewable electricity for most of the remainder. In **Indonesia**, biodiesel demand increases 5 billion litres (0.2 EJ) to make up 40% of national diesel demand. Ethanol blending reaches 0.5 billion litres by 2030 following the rollout of 5% ethanol blending on Java, Indonesia's most populous island. Enabling legislation adopted in July 2025 established a legal framework for ethanol mandates and pricing, but levels and prices have yet to be announced. This year's forecast for all biofuel use is 30% higher than last year's to reflect full implementation of 40% blending from February 2025 and higher diesel use

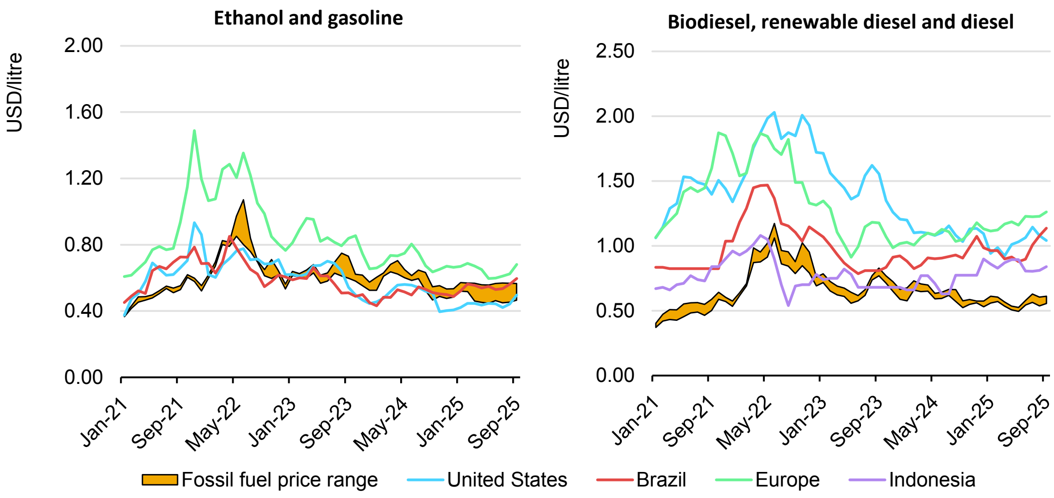
India's biofuel demand reaches 12.5 billion litres (0.3 EJ), a more than 25% upward revision from last year. This reflects a modest increase in blending expectations and 6% higher anticipated gasoline demand by 2030. India is targeting 20% ethanol blending by 2025/26, using policy instruments such as feedstock-specific pricing, guaranteed offtake agreements for ethanol, and subsidies for new capacity.

In the accelerated case, renewable energy consumption in transport increases an additional 1.8 EJ, bringing its share in total transport demand to 10%. Liquid biofuels account for the majority of the increase, assuming that the **United States** raises its ethanol shares beyond 10%; **Brazil** successfully implements all elements of its Fuel of the Future programme; **China** enforces modest blending targets; and governments expand feedstock supplies for biodiesel, renewable diesel, biojet fuel and maritime fuels.

Biofuel prices

Average prices for ethanol and biodiesel (including renewable diesel) remain close to 2024 levels. While ethanol continues to be cost-competitive with gasoline in most markets, biodiesel (including renewable diesel) costs nearly twice as much as fossil diesel in the United States and Europe, and around 50% more in Indonesia and Brazil. While diesel prices have fallen nearly 10%, biodiesel feedstock costs have not followed due to Indonesian export restrictions, higher blending targets and US plans to increase biodiesel volume obligations nearly 50% to 2027 from 2025 levels.

Biofuel and fossil fuel wholesale prices, selected markets, 2021-2025



Note: Prices are based on combined averages of free-on-board regional indices.
Source: Argus (2025), Argus Direct (Argus Media group, all rights reserved).

Stable ethanol pricing reflects predictable policy support and continued sugarcane and maize supply expansion. In the case of biodiesel and renewable diesel, however, prices have not followed diesel declines due to policy shifts and tightening international feedstock markets. Indonesia, the world's third-largest residue oil exporter after China, restricted its exports of used cooking oil and palm oil mill effluent before implementing a 40% biodiesel mandate in February 2025. This affected Europe in particular, as its demand for waste and residue oils is high. As of July 2025, EU waste and residue oil prices were at a two-year high. China also removed its export tax rebate for used cooking oil, putting further upward pressure on prices.

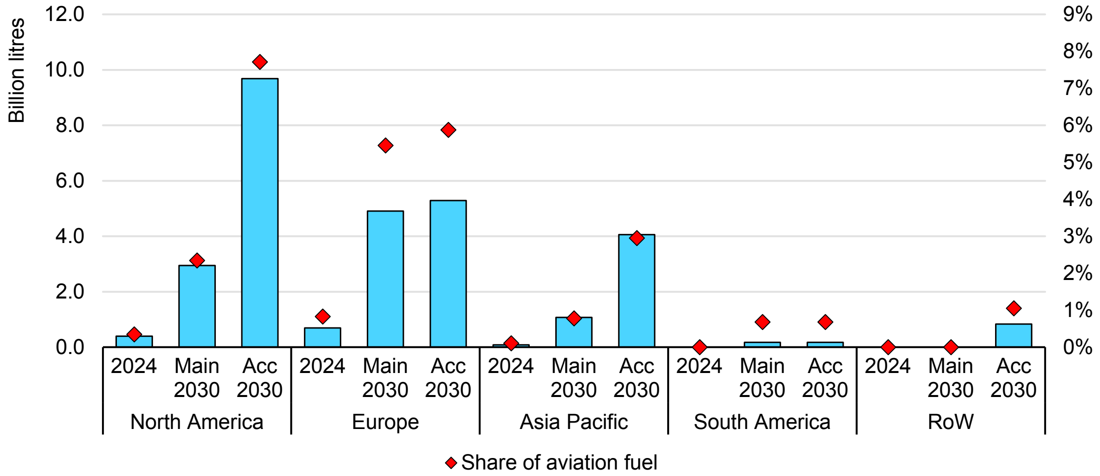
Indonesia's biodiesel blending increase in 2025 alone is equivalent to 2% of global vegetable oil exports, potentially contributing to higher global vegetable oil prices. In the United States, soybean oil futures rose nearly 20% following the June 2025 release of higher blending obligations and the prioritisation of domestic feedstocks in the proposed RFS updates. Overall, demand for biodiesel and renewable diesel feedstocks continues to outpace supply availability, putting upward pressure on prices.

Aviation

Forecast

Sustainable aviation fuel consumption is expected to expand from 1 billion litres (0.04 EJ) in 2024 to 9 billion litres (0.31 EJ) in 2030, meeting 2% of total aviation fuel demand in the main case. Mandates in the European Union and United Kingdom, incentives in the United States and blending targets in Japan drive most of this growth. The forecast remains similar to last year, however, since no new policies have been implemented since our previous (October 2024) edition of this report. E-kerosene is forecast to account for only 5% of total SAF production in 2030, since only Europe mandates its use.

Biojet fuel demand by region, main and accelerated cases, 2024 and 2030



Notes: RoW = rest of world. Shares of aviation fuel demand are based on volume.
Source: IEA (2025), Oil 2025.

Europe is forecast to lead global SAF deployment, with the European Union targeting 6% blending by 2030 under ReFuelEU Aviation legislation and the United Kingdom mandating 10% SAF by 2030. Both jurisdictions include sub-targets for synthetic fuels such as e-kerosene. However, no final investment decisions had been made for commercial-scale e-fuel facilities as of September 2025. We have therefore reduced our e-kerosene forecast by 30%, noting that full compliance with EU and UK mandates would require nearly 15 medium-sized plants to be built by 2030. While announced capacity currently stands at 2.4 billion litres – almost three times what is required to meet the EU and UK targets – no plants have yet received a final investment decision.

In **North America**, SAF demand is expected to reach 3 billion litres by 2030, or nearly 2% of total US jet fuel consumption. Most is produced and used in the United States, with Canada contributing a small amount, primarily to meet British Columbia's provincial target of lowering GHG emissions from aviation fuel by 10%. In the United States, the OBBBA extended the SAF tax credit under Section 45Z to 2029, but it reduced the maximum value from USD 0.46/litre to

USD 0.26/litre starting in 2026 – aligning it with credits for other clean fuels. Under the 45Z tax credit, fuels can receive higher credits for better carbon intensity performance.

Nonetheless, our forecast remains similar to last years, as prior estimates were already conservative and assumed no federal SAF credit availability beyond 2027. Moreover, SAF producers can still stack RFS and LCFS benefits, 45Z credits and other state credits. Under the right carbon intensity conditions, this could offset higher production costs relative to jet fuel between 2026 and 2029. In the short term, we expect SAF use in the United States to double in 2025 as producers take advantage of the final year of the higher credit rate.

Outside of the main global markets, SAF demand is growing, primarily owing to Japan's target of 10% blending by 2030 and South Korea's mandate of 1% by 2027. These two policies are expected to generate almost 1 billion litres of additional SAF demand by 2030. In Japan, Saffaire Sky Energy and Revo International began SAF production in early 2025. A final investment decision is expected later in 2025 for a 400-million-litre-per-year SAF facility at the Tokuyama refinery that would more than quadruple Japan's production capacity. South Korea's current SAF supply comes from coprocessing waste oils at local refineries, while dedicated SAF production projects are still in the early development stage.

In the accelerated case, global SAF demand more than doubles compared with the main case forecast, rising to 20 billion litres by 2030 and approaching 4.5% of global jet fuel use. The United States remains the single largest source of potential growth, with significant capacity announced and the feedstock base to support it. However, realising this potential would require stronger long-term policy commitments, such as increased credit values or a federal SAF mandate.

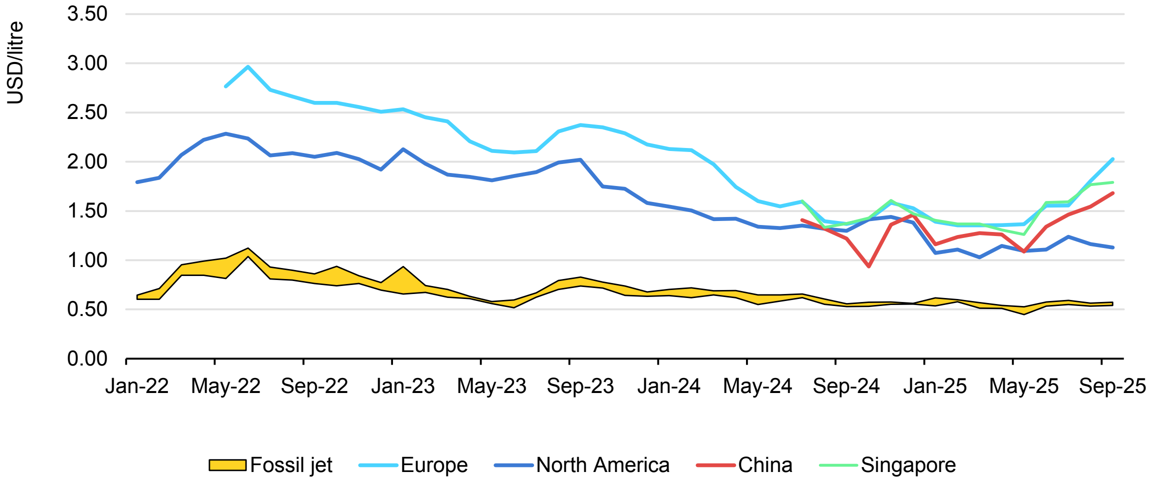
An additional 3 billion litres of SAF demand comes from Southeast Asia, assuming India, Indonesia, Malaysia and Thailand implement the policies required to achieve their announced targets. The accelerated case also assumes that the European Union and the United Kingdom introduce financial support – such as contracts for difference – to enable construction of up to 15 commercial-scale e-kerosene plants.

Prices

Biojet fuel prices dropped more than 30% between 2023 and mid-2025, falling to a low of USD 1.35/litre at the beginning of 2025 and temporarily narrowing the price gap with fossil jet fuel to USD 0.80/litre. While cost declines are good for consumers, these prices remain well below estimated production costs – particularly for fuels derived from waste oils, for which the break-even price is still above USD 1.80/litre.

The temporary price drop stems from excess capacity entering the market ahead of implementation deadlines for policies in Europe and the 45Z SAF tax credit in the United States, which had been set at USD 0.46/litre to 2027. SAF prices are expected to rise in upcoming years as European blending mandates ramp up and supply becomes balanced with demand.

Biojet and fossil jet fuel prices, 2022-2025



Notes: Prices are based on the combined averages of regional and country indices for HEFA-SPK in the case of biojet fuel. Prices are wholesale free-on-board prices, before taxes and delivery fees. Europe price estimates follow a similar methodology to EASA estimates and match the Aviation Biofuels category in that publication.
Source: Argus (2025), Argus Direct (Argus Media group, all rights reserved).

In the United States, OBBBA reforms and proposed RFS changes in 2025 significantly reshaped SAF credit eligibility to favour domestic feedstocks. While the 45Z tax credits were extended to 2029, their value was reduced by 43% for SAFs. In addition, SAFs produced from imported feedstocks no longer qualify for tax credits and receive only half the RFS credits awarded to fuels made from domestic materials.

As a result, imported SAFs and SAFs made from imported feedstocks will now receive almost 60% less total support than in 2025, depending on feedstock and jet fuel prices and credit value, making them largely uncompetitive under existing market conditions. At the same time, the proposed removal of indirect land use change factors from GHG calculations raises credit values for SAF made from domestic soybean oil, offsetting the reduction in base credit value.

Under ReFuelEU Aviation legislation, fuel suppliers that fail to comply with blending mandates will pay penalties set at twice the price difference between

SAF and fossil jet fuel, effectively ensuring SAF use. Additionally, the European Union will phase out free allowances for aviation under the ETS by 2026. Carbon prices would need to rise to well above EUR 200/t CO_2 to incentivise SAF uptake beyond mandated levels.

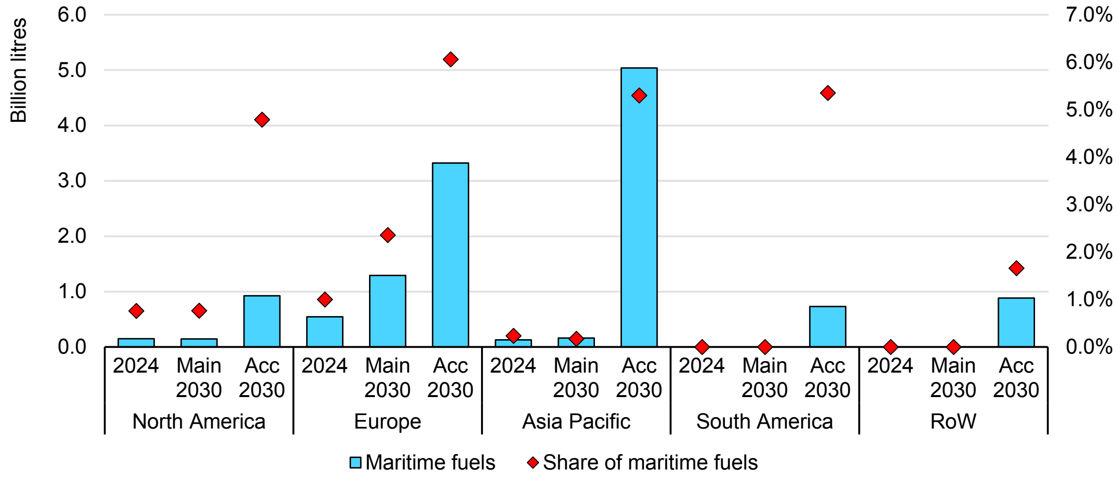
Maritime

Forecast

Maritime biodiesel demand is projected to double to 1.6 billion litres (0.05 EJ) by 2030, making up 0.7% of total maritime fuel demand. The primary region for growth continues to be Europe, where fuel suppliers are required to meet GHG intensity reduction targets of 2% by 2025 and 6% by 2030 and are subject to carbon pricing under the EU ETS. Elsewhere, expansion remains limited due to the absence of mandates and incentives.

The IMO's proposed Net-Zero Framework would change this trajectory if implemented. While we did not factor the framework into our main case analysis, including it in the accelerated case causes biodiesel use in shipping to rise to nearly 5% of total maritime fuel demand by 2030. The framework proposes tiered GHG intensity reduction targets, with ships facing charges of USD 380/t CO_2-eq for missing the first tier and USD 100/t CO_2-eq for missing the second tier. The IMO focus section below discusses the implications of this framework further.

Maritime biodiesel demand by region, main and accelerated cases, 2024 and 2030



Notes: RoW = rest of world. Shares reflect shipping fuel demand.
Source: IEA (2025), Oil 2025.

The main-case maritime fuel forecast remains similar to last year's, with biodiesel demand for shipping expanding almost 1 billion litres in Europe as the region complies with ReFuelEU Maritime legislation requiring GHG intensity reductions of 2% by 2025 and 6% by 2030. Biofuel expansion to meet policy obligations is modest, since planned LNG use in shipping and shore power count towards GHG targets. In Southeast Asia, demand is projected to increase 25% by 2030, mainly because the Port of Singapore serves ships that belong to companies with targets or that dock at EU ports. Biofuel bunkering is already on the rise, and sales of biodiesel blends at the Port of Rotterdam and the Port of Singapore increased 10% from 2022 to 2024.

In the accelerated case, biodiesel demand climbs to 11 billion litres (0.4 EJ), accounting for nearly 10% of global biodiesel and renewable diesel demand. The IMO's proposed Net-Zero Framework targets an 8% carbon intensity reduction by 2030, but ships failing to meet this aim can purchase credits from over-compliant ships or pay into a fund at USD 380/t CO_2-eq.

We expect most ships to either blend cleaner fuels directly or purchase credits from over-compliant ships to avoid paying into the fund, since LNG, biodiesel and biomethane all offer cheaper emissions reductions and are commercially available. Bio-methanol, e-methanol and e-ammonia are more expensive and in much shorter supply, but some shippers have invested in compatible ships, and four projects linked to shipping offtake agreements (0.06 PJ of fuel) have reached final investment decisions with one already operational.

Shippers are also required to meet a more stringent 20% GHG intensity reduction target by 2030 or pay into a fund at USD 100/t CO_2-eq. In this case, we expect shippers to pay into the fund rather than reduce their emissions since there are few mitigation options available at USD 100/t CO_2-eq. The IMO has yet to decide on important details such as default carbon intensity values for fuels; how indirect land use change is to be treated; how collected funds will be distributed; how credits will be traded; and many other aspects.

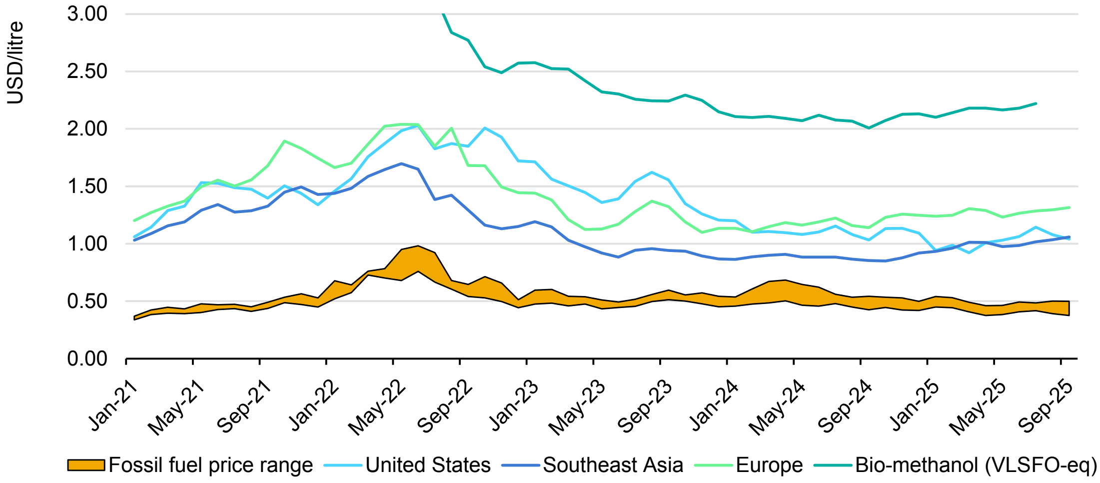
Prices

Biodiesel prices remain similar to 2024 in 2025, and averaged twice the price of very-low-sulphur fuel oil (VLSFO). Ports typically sell biofuel blends of 20-30%, meaning vessels effectively pay a premium of 25-35%. Prices tend to be lower in Southeast Asia owing to shorter supply chains, while European fuel often incorporates waste and residue oils imported from Asia, complicating logistics and raising compliance costs.

For the European Union, this price differential will shrink as maritime fuel emissions are integrated into the EU ETS. However, closing the price gap would require a price of almost USD 200/t CO_2-eq for the lowest-GHG-intensity biofuels.

Maritime biodiesel prices are unlikely to drop further over the forecast period because of strong demand for feedstocks and the high cost of alternatives such as bio-methanol, e-methanol and e-ammonia. For instance, bio-methanol prices averaged USD 2.15/litre of VLSFO-eq in 2025, nearly double maritime biodiesel prices.

Maritime biodiesel and fossil fuel prices by region, main case, 2021-2025



Notes: VLSFO = very-low-sulphur fuel oil. Prices are wholesale free-on-board prices, before taxes and delivery fees.
Source: Argus (2025), Argus Direct (Argus Media group, all rights reserved).

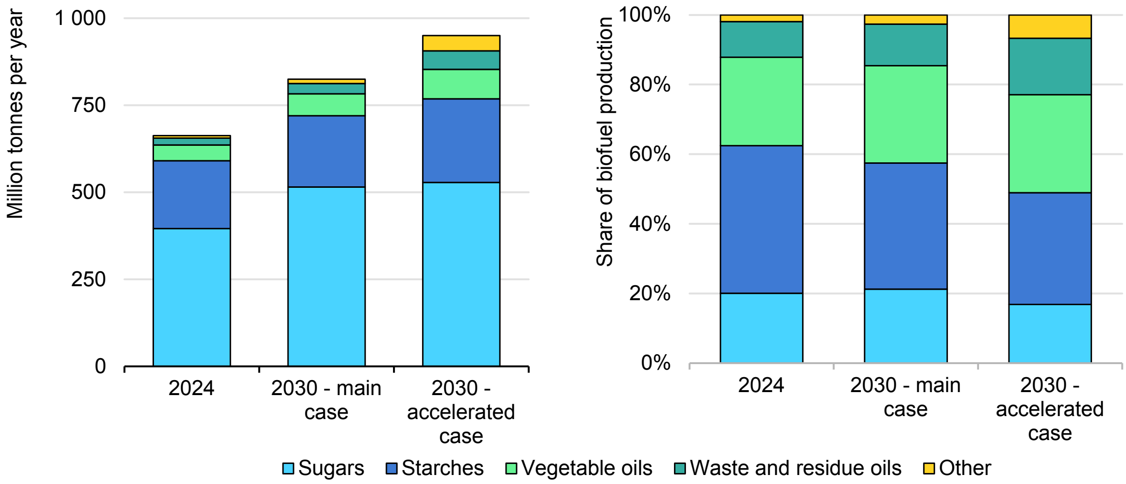
Feedstocks

Biofuel feedstock demand rises to nearly 825 Mt in 2030 in the main case, a nearly 25% increase from 2024. Almost 80% of this growth is linked to road transport fuels. The use of vegetable oils – including soybean, palm and rapeseed oil – grows by nearly 20 Mt, while waste and residue oil use rises 10 Mt for biodiesel, renewable diesel and SAF production. As a result, vegetable oils and waste and residue oils together support 40% of total biofuel production by 2030, up from 36% in 2024. In the accelerated case, this share rises further to nearly 45% of total biofuel production.

In the road sector, sugarcane and maize use expand to meet rising ethanol mandates in Brazil and India, while vegetable oil demand grows mainly to support biodiesel and renewable diesel production in Latin America and Southeast Asia. In the United States, recent tax credit reforms and proposed RFS rule changes favour domestic soybean and canola oil, spurring increased biodiesel, renewable diesel and SAF production from these feedstocks. In contrast, growth in the use of vegetable oils in Europe's road biofuel sector is limited, as residue oils are prioritised to comply with RED III sustainability criteria and national GHG-based targets.

Although SAF production accounts for just 2% of total feedstock demand in 2030, it places growing pressure on already-constrained waste and residue oil supplies. Owing to their low lifecycle emissions and eligibility under schemes such as CORSIA and ReFuelEU Aviation, these oils are projected to provide 55% of SAF feedstocks. Alcohols and lignocellulosic biomass are expected to remain niche feedstocks in the main case, used primarily in the United Kingdom and the European Union.

Biofuel feedstock demand by feedstock mass (left) and share of fuel production (right), main and accelerated cases, 2024 and 2030

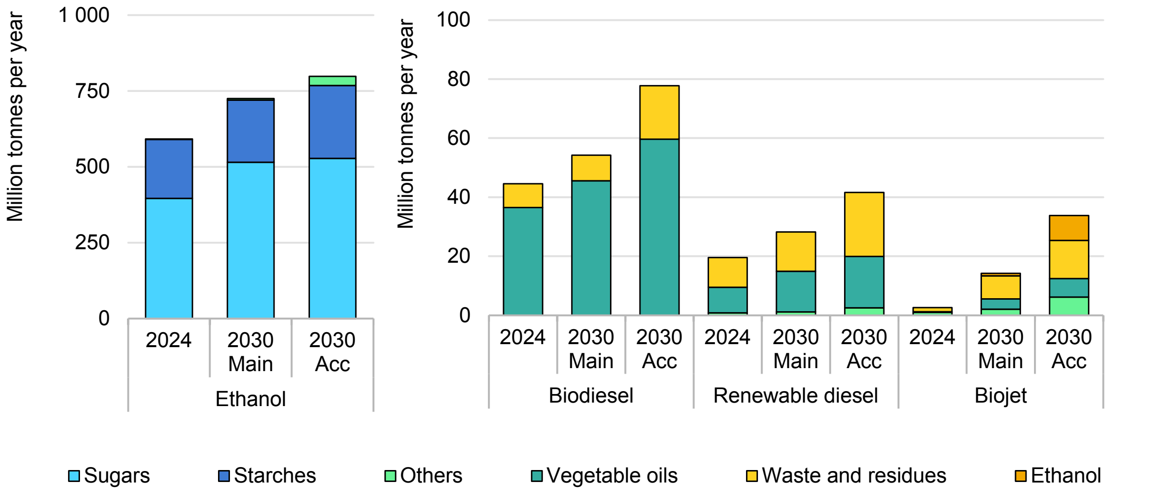


Notes: “Sugars” includes sugarcane, molasses and sugar beets. “Starches” covers maize, wheat, rice, cassava and other starches. “Vegetable oils” refers to soybean, rapeseed, palm and other vegetable oils. “Waste and residue oils” represents used cooking oil, tallow and palm oil mill effluent and other oils. “Other” includes woody wastes and residues for cellulosic ethanol and Fischer-Tropsch fuel production.

Maritime biofuel feedstock demand remains modest in the main case, reaching just 1.4 Mt by 2030. Biodiesel is the main maritime biofuel and is expected to be produced largely from waste and residue oils or certified vegetable oils to satisfy FuelEU Maritime requirements (these volumes are included in total biodiesel feedstock demand). In the accelerated case, feedstock demand for maritime biofuels increases sevenfold, though the specific mix of eligible feedstocks will depend on forthcoming IMO guidelines.

In the accelerated case, total feedstock demand grows an additional 125 Mt/year to reach 950 Mt/year by 2030. Most of this increase supports expanded production of biodiesel, renewable diesel and biojet fuel to meet maritime blending goals, RED III targets in Europe and faster SAF deployment. The use of cellulosic ethanol and Fischer-Tropsch fuels nearly quadruples to nearly 45 Mt/year.

Biofuel feedstock demand by fuel type, main and accelerated cases, 2024 and 2030



Notes: "Sugars" includes sugarcane, molasses and sugar beets. "Starches" refers to maize, wheat, rice, cassava and other starches. "Vegetable oils" indicates soybean, rapeseed, palm and other vegetable oils. "Waste and residue oils" refers to used cooking oil, tallow and palm oil mill effluent and other oils. "Other" includes woody wastes and residues for cellulosic ethanol and Fischer-Tropsch fuel production.

Policies and assumptions, main and accelerated cases

Country or region	Policies, assumptions and blending levels in the main and accelerated cases
United States	**Main case:** Proposed RFS commitments remain in place. IRA provisions are implemented as presented in the OBBBA. Ethanol blending reaches 10.9% by 2030. Renewable diesel expands according to planned capacity additions from projects in advanced development stages. Renewable diesel blending reaches 9.5% in 2030. Biodiesel blending declines to 3% while biojet fuel supply and demand expand to accommodate 2.5% blending for all jet use. **Accelerated case:** A strengthened version of the RFS, extended IRA credits, deployment of E15 blending pumps and stronger state-level low-carbon fuel standards boost domestic biofuel demand. Combined, these policies help achieve blending rates of 13% for ethanol and 4% for biodiesel. Renewable diesel blending increases to 10.4%, matching domestic production capacity for planned projects. Biojet fuel blending expands to 8.6%, 80% of the way to achieving the SAF Grand Challenge goal. Ethanol production increases to meet both domestic and net export demand using existing ethanol manufacturing capacity.

Country or region	Policies, assumptions and blending levels in the main and accelerated cases
Brazil	**Main case:** Mandatory ethanol blending rises to 30%, and hydrous ethanol purchases expand so that total blending is 58% by 2030. Biodiesel blending reaches B13 in 2024, climbing to B15 by 2026 and B17 by 2030. There is a small amount of renewable diesel blending (0.8%) by 2030, based on planned project additions. Two-thirds of new ethanol production comes from maize and most of the remainder from sugar cane. **Accelerated case:** Brazil achieves all Fuel of the Future programme goals. It realises B15 blending by 2026 and B20 by 2030. Green diesel (renewable diesel) climbs to 3% blending in 2030. Mandatory ethanol blending rises to 35%, bringing the total to 61%. The proposed aviation GHG emissions reduction target is implemented, requiring 3.4% biojet fuel blending by 2030. Enough ethanol, biodiesel, renewable diesel and biojet fuel are produced to serve domestic consumption, and ethanol production increases further to meet export demand.
India	**Main case:** Ethanol blending reaches 16% on average across the country by 2030, and all fuel ethanol is produced domestically. Although E20 fuel became available in 2023, the forecast assumes that vehicle incompatibility and insufficient production capacity limit its uptake. Biodiesel blending remains around 0.25%. **Accelerated case:** India achieves its 20% ethanol blending mandate in 2026 and its 5% biodiesel blending goal by 2030, assuming it resolves vehicle compatibility issues and establishes feedstock collection for biofuel production. It continues to support domestic production and allows fuel ethanol imports of up to 20% of demand. It also follows through on ambitions for biojet fuel blending, reaching 2% by 2028 for international flights. This requires dedicated policy support and the development of new feedstock pathways for residue fats, oils and greases; vegetable oils grown on marginal land/cover crops; and alcohol-to-jet capacity.
China	**Main case:** No significant changes affect ethanol or biodiesel policies. Ethanol blending remains near 2% and biodiesel at 0.5%. **Accelerated case:** China implements policies aligned with its bioeconomy plan, including blending targets of 4.5% for ethanol, 3.5% for biodiesel and renewable diesel, and 1.5% for SAFs in domestic aviation by 2030. It continues to allow ethanol imports of up to 10% of demand from the United States and other countries. Exports continue for biodiesel but drop to zero for renewable diesel and biojet fuel. Production of both fuels is used to satisfy domestic demand.

Country or region	Policies, assumptions and blending levels in the main and accelerated cases
Indonesia	**Main case:** Biodiesel blending increases to 35% for transport and non-transport uses. Renewable diesel blending expands to 3% by 2030. Ethanol demand rises to permit 1.2% blending, reflecting fuel distributor targets and Indonesia's intention to blend more ethanol. Biojet fuel production and use climb based on planned projects, reaching 2% of jet fuel demand by 2030. **Accelerated case:** Indonesia meets the B50 mandate for transport and non-transport fuel consumption, which will require additional renewable diesel manufacturing capacity. It also enforces 4% SAF blending by 2030 and achieves 3% ethanol blending by 2030.
Europe	**Main case:** EU member countries with implementation plans meet the RED III goals and the bloc meets ReFuelEU Aviation and ReFuelEU Maritime aims (or their own domestic targets if more stringent), and non-EU countries achieve domestic targets. Biojet fuel use expands to meet the ReFuelEU targets of 2% by 2025 and 6% by 2030, reaching 5% biojet fuel by 2030 and 1% e-fuels. As per the ReFuelEU proposal, feed/food crop-based fuels are not eligible, and fuels must otherwise meet the requirements of RED II, Annex IX, Part A or Part B. • Germany's GHG emissions reduction target climbs to 25% by 2030, up from 8% in 2024. Biodiesel and ethanol blending remain steady, while renewable diesel expands to 3.5%. • France meets its 9% ethanol and 9.9% biodiesel blending targets (on an energy basis). Ethanol blending increases to 16% assuming ongoing support for E85; biodiesel blending remains flat; renewable diesel blending expands to 3.5%; and biojet fuel reaches 5% by 2030. • In Spain, ethanol blending climbs to 8%; biodiesel to 7%; renewable diesel to 6%; and biojet fuel to 5% by 2030. • Finland, the Netherlands and the United Kingdom all achieve nearly 10% ethanol blending. Sweden reduces its blending obligations from 58% to 6% by 2030 for biodiesel, and from 24% to 6% by 2030 for ethanol; it also reaches 3% biojet fuel blending. Finland reduces its distribution obligation to 22.5% by 2027, down from its original target of 30%. In Italy, renewable diesel blending expands to 5%. • The United Kingdom implements 10% SAF blending by 2030, with the mandate starting in 2025. **Accelerated case:** The EU bloc meets RED III targets. Sweden and Finland reinstate their former GHG intensity and blending requirements. The European Union maintains and strengthens sustainability requirements for biofuels, which limits some imports.

Country or region	Policies, assumptions and blending levels in the main and accelerated cases
EU Shipping	**Main case:** REFuelEU is the only driver of renewable fuel use in the main case, boosting renewable fuel use in transport to near 1% of maritime fuels. **Accelerated case:** The IMO implements its Net Zero Framework by 2028 and shipping companies meet the base target by blending renewable fuels, primarily biodiesel. Renewable fuel demand in the shipping sector climbs to 0.5 EJ.
Other countries	**Main case:** Canada continues with its Clean Fuel Regulations, and Malaysia's B20 mandate is implemented. Thailand makes progress on its E20 target, reaching 16% blending by 2030, while biodiesel use expands to 8.5% based on government support plans. Singapore's renewable diesel and biojet fuel production expand to fill domestic shortfalls in the rest of the world, and biojet production rises to meet the 3% consumption target for 2030. Argentina's biodiesel blending climbs to 8% and ethanol to 12%. Colombia reaches 10% ethanol blending by 2030, while biodiesel blending rises to 12% over the forecast period. Japan pursues 10% SAF use by 2030. **Accelerated case:** Canada follows the United States in supporting SAFs. Malaysia expands biodiesel blending to 20% for the industry sector and supports an HVO/SAF refinery and domestic biojet fuel use. Singapore achieves 5% SAFs by 2030 and the United Arab Emirates meets its 0.7-billion-litre SAF target, with 0.4 billion coming from biojet fuel. Colombia pursues 13% biodiesel blending. Thailand achieves 20% ethanol blending by 2026 and allows 10% ethanol imports. Egypt, Ghana, Kenya, Nigeria, Mozambique, South Africa, Uganda, Zambia and Zimbabwe all follow through on biofuel mandates of up to 10% ethanol blending and 5% biodiesel blending through 2030.

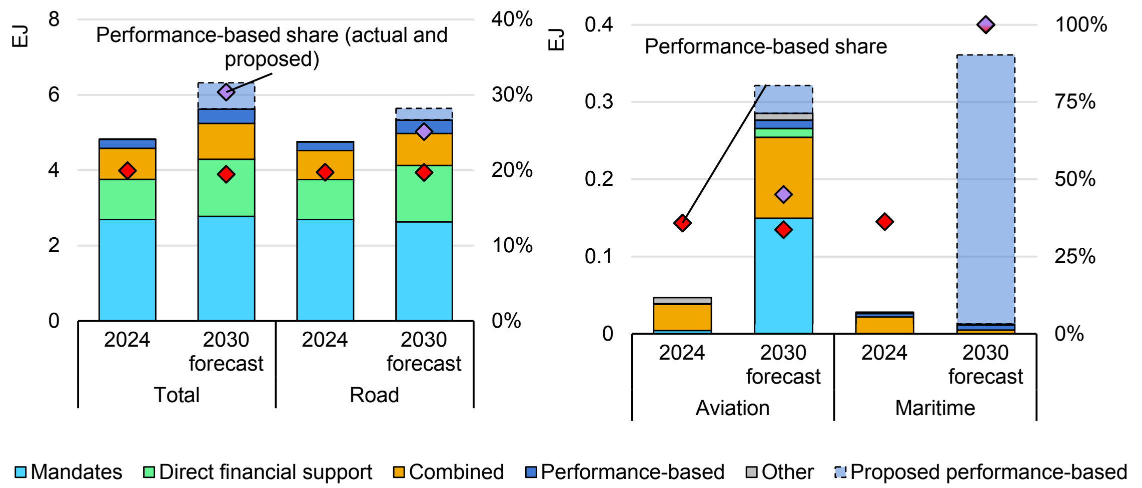
However, growth in these fuels remains limited in the United States, where OBBBA reforms continue to favour conventional vegetable oils. As a result, we have reduced estimated US production from non-lipid SAF feedstocks by nearly 30% compared with previous forecasts. Sugar and starch use rises just over 20%, largely in Brazil, India, Indonesia and the United States. Europe remains the largest demand centre for waste and residue oils, though consumption is also rising in Southeast Asia to supply Singapore's refining capacity and meet growing biodiesel demand in India.

Policy trends

Performance-based standards are expected to underpin one-third of total biofuel demand by 2030

Governments are increasingly shifting from volumetric mandates and direct incentives to performance-based frameworks that reward GHG reductions. Considering all proposed policy changes, performance-based standards could be the foundation for 30% of total biofuel demand by 2030, up from just under 20% in 2024. In the first half of 2025 alone, France, Spain, the Netherlands, Czechia and Romania proposed transitioning to GHG intensity-based systems (see the EU focus section below); the IMO announced plans to introduce a global fuel standard (see the IMO focus section); and the United States decided to maintain performance tax credits, although with modifications (see the US focus).

Liquid biofuel demand by primary support policy, main case, 2024 and 2030



Notes: Primary support policy means the policy that closes the cost gap between biofuels and fossil fuels. “Performance-based” includes GHG intensity reduction targets and GHG performance-linked incentives. “Mandates” indicates volume and energy mandates. “Direct financial support” includes production-linked incentives and tax incentives. “Combined” accounts for jurisdictions where more than one policy type is needed to close the cost gap (e.g. the United States for biodiesel, renewable diesel and SAF). “Other” includes market-driven deployment and offtake agreements.

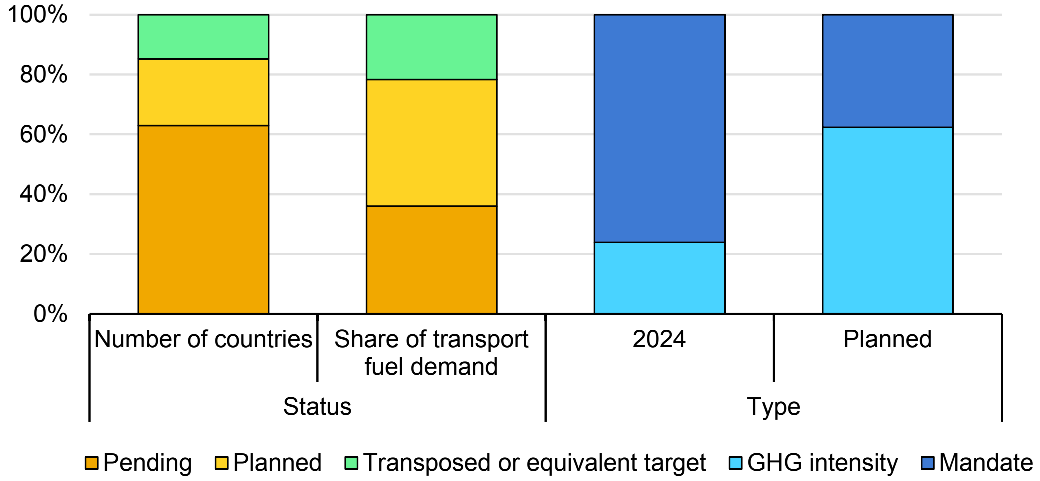
In Canada, California and Europe (Germany and Sweden), performance-based standards are the primary tools that enable deployment of low-carbon fuels by closing the cost gap with fossil fuels. In other markets, such as the United States and Brazil, performance-based systems complement volume-based mandates. In the United States, for example, the 45Z tax credit provides up to USD 0.26/litre depending on a fuel’s GHG performance, and biodiesel, renewable diesel and SAF use would be uneconomic without this support.

In Brazil, the RenovaBio programme requires minimum GHG reductions from producers but also imposes blending targets. It rewards GHG intensity improvements but does not drive demand on its own. The IMO is also advancing a performance-based framework, using a global fuel standard as its principal tool to support the uptake of low-emissions fuels in international shipping.

Performance standards are to cover more than 60% of EU transport fuel demand by 2030

By 2030, GHG intensity regulations will apply to the majority of EU transport fuel demand if current national plans are implemented – marking a major shift from traditional volume-based biofuel mandates. Proposed policies reward emissions reductions rather than additional fuel volumes, creating stronger incentives for producers to improve their performance.

RED III transposition by status and policy type, main case, 2024



Notes: Shares by transposition status and policy type are based on total EU transport energy demand in 2024 in the main case. “Transposed or equivalent target” refers to either a 14.5% GHG intensity reduction target or a 29% renewable energy share target. Transposed or equivalent means the EU country has implemented legislation that meets the RED III goals. “Planned” designates countries with proposed legislative changes that meet the RED III goals. “Pending” are EU countries that have yet to propose legislative changes to align with RED III.

With more than 60% of the EU fuel market expected to be covered by GHG intensity systems, there is growing potential to scale up investment in larger lower-carbon fuel projects. Moreover, as 17 countries have yet to propose new targets, there is upside potential to expand this market even further. Effective deployment will require the alignment of national systems to ensure that GHG reductions are consistently recognised and rewarded across all EU markets.

The 2023 amendments to the updated Renewable Energy Directive allow member countries to choose either a 14.5% GHG intensity reduction or a 29% renewable energy share by 2030. The GHG intensity reduction or renewable share goals apply to total aviation, shipping and road transport use across all energy types (fossil fuels, biofuels, electricity and renewable fuels of non-biological origin). The previous regulation (RED II) required member states to meet a less ambitious target of 14% renewable energy in transport by 2030 and a 6% GHG intensity reduction under the Fuel Quality Directive. The GHG obligation is technology-neutral, allowing countries to design programmes that incentivise pathways with the lowest GHG abatement cost.

However, for emerging technologies such as advanced biofuels and hydrogen-based fuels, RED III includes sub-mandates to promote expansion. To further incentivise lower-emitting pathways and emerging technologies, states opting for a mandate may also apply a set of multipliers on the energy content of selected fuels by sector when counting them towards the share of renewables in transport.

Although member states pledged to transpose RED III targets into their domestic legislation by 21 May 2025, few countries have yet adopted the RED III transport targets. However, France, Spain and the Netherlands have released proposals, opting to shift from a renewable energy share to a GHG intensity-based target, while Romania has included both GHG intensity and renewable energy mandates in its updated legislation.

To date, mandates remain the primary policy tool, but four of the largest EU markets have chosen GHG intensity obligations. Considering member states with active or proposed GHG intensity obligations, nearly 60% of EU transport energy demand will be covered by a GHG intensity obligation.

Several key implications are associated with EU member states transitioning to GHG intensity targets. A GHG-based target can stimulate competition among biofuels, biogases, electricity, hydrogen and hydrogen-based fuels to provide the lowest cost reduction. It also provides value for further GHG intensity reductions, offering new compliance pathways for fuel suppliers, allowing them to prioritise emissions reductions over fuel supply expansion if it is more financially attractive.

Nearly all renewable fuel pathways can achieve near-zero GHG emissions under the right incentive framework. In line with moving towards GHG intensity regulations, there is an emerging trend among member states to eliminate multipliers, either entirely or for selected fuels. Removing multipliers makes it easier to assess the impact of national policies in advancing the use of renewables in transport.

RED III transposition – national policy updates and market shares, main case, 2024

Country	Previous target (type)	Updated target (type)	Share of EU transport fuel demand
Germany	25.0% (GHG obligation)	25.1% (GHG obligation)	18%
France	9.4% (mandate)	18.7% (GHG obligation)	15%
Spain	12.0% (mandate)	15.6% (GHG obligation)	12%
Netherlands	28.0% (mandate)	27.1% (GHG obligation)	7%
Romania	14.0% (mandate)	14.5% (GHG obligation)	2%
Belgium	13.9% (mandate)	29.0% (mandate)	4%
Portugal	16.0% (mandate)	29.0% (mandate)	2%
Ireland	25.0% (mandate)	49.0% (mandate)*	2%
Finland	30.0% (mandate)	34.0% (mandate)	1%
Lithuania	16.8% (mandate)	29.0% (mandate)	1%

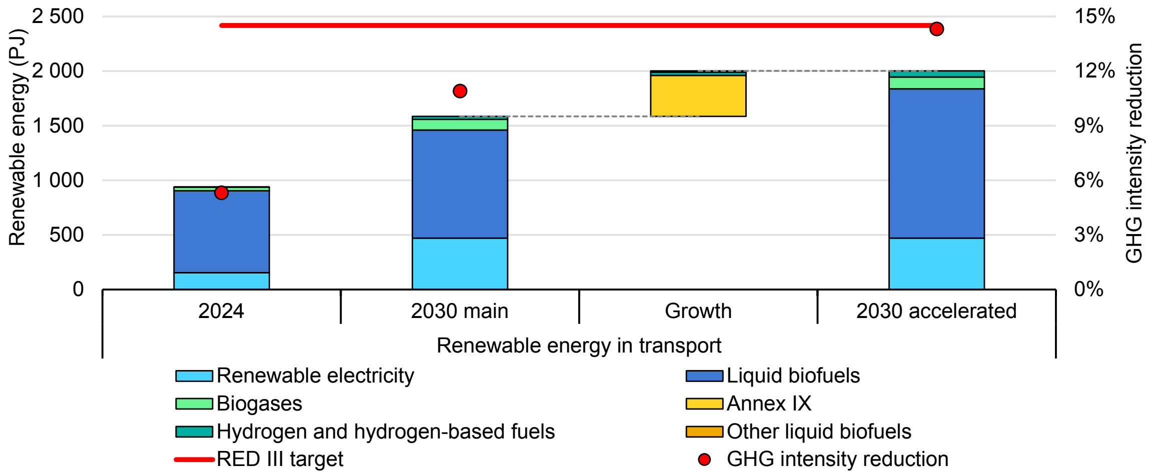
*Ireland has published an indicative annual trajectory of its Renewable Transport Fuel Obligation that is compliant with RED III, but a binding 2030 target for renewables in transport has not been released.

Note: TBA = to be announced.

Realising RED III ambitions across the European Union will require scaled-up deployment of emerging technologies

Emerging technologies make up more than 95% of the fuel growth needed to meet EU targets across the European Union. Employing these technologies could reduce emissions intensity and help countries meet the RED III set of sub-mandates to expand the use of waste- and residue-based energy sources (see RED III Annex IX A) and hydrogen-based fuels. However, achieving the necessary level of growth depends on EU member states diversifying their feedstocks and deploying new biofuel processing technologies and hydrogen-based fuels.

EU renewable energy in transport, main and accelerated cases, 2024 and 2030



Note: The “other liquid biofuels” category covers liquid biofuels not derived from feedstocks included in Annex IX of RED III.

Considering all operating Annex IX A-compatible liquid biofuel projects and those under construction or awaiting a final investment decision, EU production capacity reaches 74 PJ by 2030, covering only 15% of projected demand in 2030 in the accelerated case. Biomethane production from wastes and residues could rise to nearly 110 PJ by 2030, meeting another 25% of demand. The remainder of demand would be satisfied by processing advanced feedstocks such as agricultural and industrial residues, intermediate crops and crops grown on marginal land. In all cases, member states will need to encourage expansion through financial support for emerging technologies and clear guidance on biomethane use in transport and advanced feedstocks.

RED III sub-mandates for waste- and hydrogen-based fuels

Sub-mandate	Feedstocks	Share in transport energy by 2030
Hydrogen and hydrogen-based fuels	Hydrogen produced from renewable electricity	1%
Annex IX Part A	Agricultural, forestry, industrial and municipal wastes, algae, animal manure and sewage sludge	5.5%*
Annex IX Part B (limit)	Used cooking oil and animal fats	1.7%

*The combined share of advanced biofuels and biogas produced from the feedstock listed in Part A of Annex IX and of hydrogen and hydrogen-based fuels in the energy supplied to the transport sector is at least 5.5% in 2030, of which a share of at least 1 percentage point is from renewable fuels of non-biological origin in 2030.

Note: Further details on specific feedstocks and additional sustainability requirements are outlined in Annex IX of Directive (EU) 2018/2001 of the European Parliament and of the Council of 11 December 2018 on the Promotion of the Use of Energy from Renewable Sources (RED II).

Source: Official Journal of the European Union (2018), Directive (EU) 2018/2001.

Similarly, achieving the RED III mandate for hydrogen-based fuels will require an additional 57 PJ of fuel supply. To date, only four plants have received final investment decisions, accounting for 2 PJ of production capacity. However, more than 500 PJ of announced project capacity has been announced to produce ammonia, methanol, e-kerosene and e-methane. The European Union plans to support shipping and aviation fuels through its Clean Industrial Deal and Sustainable Transport Investment Plan, with additional details to be disclosed near the end of 2025. With the right financial support, there is still time to commission additional production capacity to support achievement of the 2030 target.

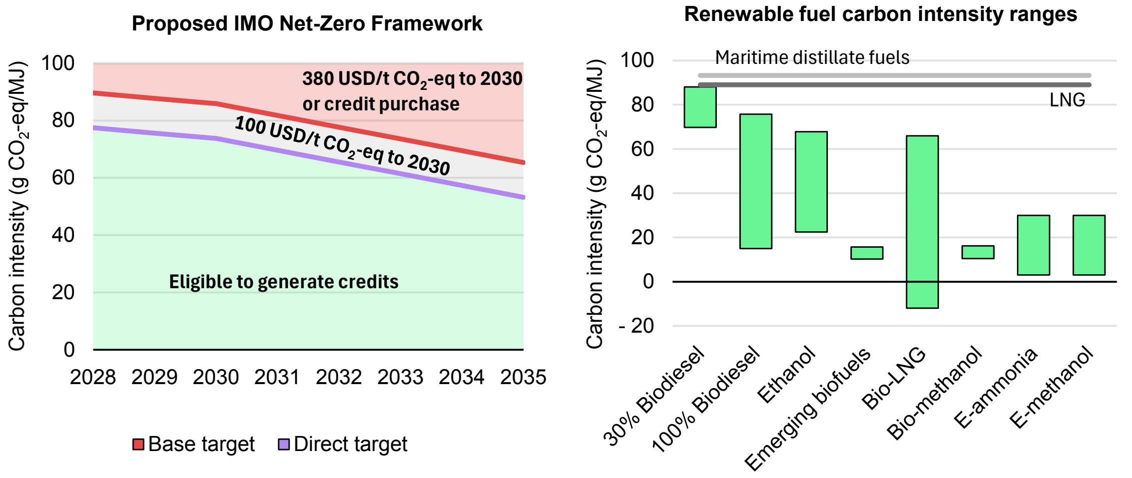
The tide is rising for renewable maritime fuels

On 11 April 2025, the IMO reached a provisional agreement on a global GHG fuel standard for international shipping. We estimate this framework could result in 0.4 EJ of new renewable fuel demand by 2030 in the accelerated case, and 2.5-3.5 EJ by 2035. In the short term, biodiesel, renewable diesel and bio-LNG are likely to meet most new demand owing to their commercial readiness, availability and ship compatibility. By 2035, however, there is considerable uncertainty around which fuels – and how much – will be used to meet the IMO standard.

The final vote on its implementation is still pending, as are key details such as the treatment of indirect land use changes; default carbon intensities; credit trading and banking rules; post-2030 remedial unit pricing; verification protocols; and the integration of revised energy efficiency requirements. Fuel blending is also not mandatory, so shipowners may instead purchase remedial units. Formal adoption is expected in October 2025, with entry into force in 2028.

The framework includes two GHG intensity targets: a **base target** with a USD 380/t CO_2-eq price; and a more stringent **direct compliance target** priced at USD 100/t CO_2-eq. The targets aim to cut GHG intensity by 8% (base) and 21% (direct) by 2030, rising to 30% and 43% by 2035. Ships not meeting the base target may buy surplus credits from over-compliant vessels, use banked compliance, or purchase remedial units at USD 380/t CO_2-eq. Ships failing to meet the direct target must buy remedial units.

Proposed IMO Net-Zero Framework and fuel carbon intensity ranges, 2028-2035



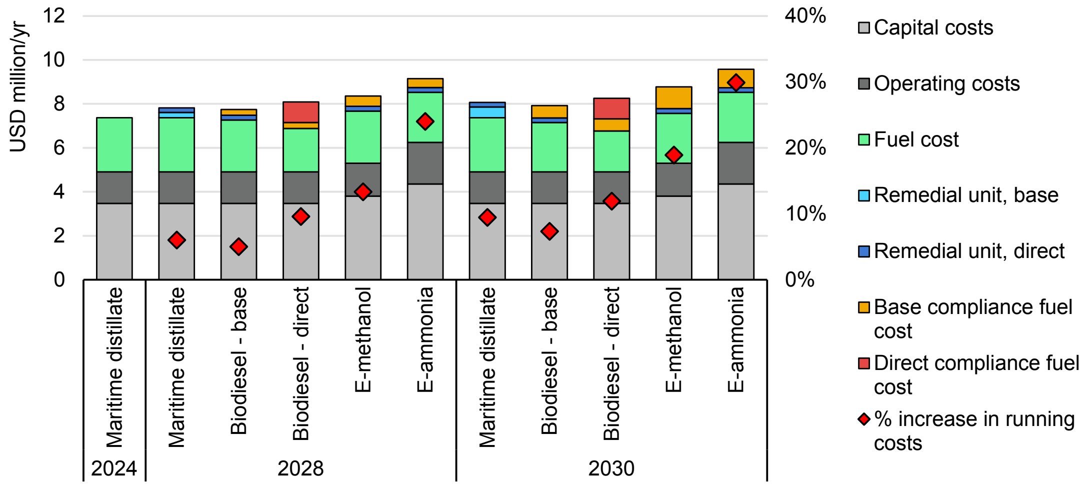
Notes: Fuel carbon intensity ranges are based on EU default values in Regulation (EU) 2023/1805 and Regulation (EU) 2018/2001. Maritime distillate fuels range from 90.77 to 91.39 g CO_2-eq/MJ, and LNG assumes 87 g CO_2-eq/MJ with 2.6% slippage. "Emerging biofuels" includes cellulosic ethanol and Fischer-Tropsch renewable diesel. "Bio-methanol" covers production from wastes and residues only. "E-ammonia" and "E-methanol" values are derived from IEA calculations using 30 g CO_2-eq/MJ based on Brazil's grid electricity, and 3 g CO_2-eq/MJ based on 100% renewable electricity and biogenic CO_2.

Sources: IMO (2025), Draft revised MARPOL Annex VI; Official Journal of the European Union (2018), Directive (EU) 2018/2001; and Official Journal of the European Union (2023), Regulation (EU) 2023/1805 on the Use of Renewable and Low-Carbon Fuels in Maritime Transport, and Amending Directive 2009/16/EC.

Many renewable fuels have lower carbon intensities than conventional maritime fuels and could support compliance (biodiesel and bio-LNG are especially promising owing to their compatibility with existing infrastructure and commercial maturity). Ethanol is another option but will require compatible ship engines, which are not yet in broad use. E-methanol, e-ammonia and bio-methanol consumption currently remain limited by fleet compatibility and market availability, but they hold promise for the future. Over 330 methanol and 38 ammonia dual-fuel ships are on order according to DNV, and e-methanol offtake agreements now support one operational plant and three more that have received final investment decisions. E-fuel production is also unaffected by biofuel feedstock constraints as it relies on renewable electricity.

To 2030, most ships are likely to blend biodiesel to meet the base target, as blending offers the lowest-cost compliance pathway. A 9% blend of biodiesel at 15 g CO_2-eq/MJ would raise operating costs nearly 7%, compared with almost 9% to pay for remedial units directly. Meanwhile, e-fuels remain cost-prohibitive. Should most ships buy remedial units at USD 100/t CO_2-eq, the IMO could generate nearly USD 10 billion/year. The IMO has stated that its fund will offer support for adoption and R&D for low/near-zero GHG fuels and energy sources; a just energy transition for seafarers; national action plan development; and economies adversely affected by implementation.

Ship running costs to meet IMO base target using selected fuels, 2024, 2028 and 2030



Notes: Maritime distillate and biodiesel prices are based on average 2024/25 market prices and assume a carbon intensity of 15 g CO_2-eq/MJ for waste- and residue-based biodiesel. Values for e-ammonia (USD 60/GJ) and e-methanol (USD 70/GJ) are based on estimated production costs, assuming a carbon intensity of 3 g CO_2-eq/MJ and operating with 100% renewable electricity. Estimates are for a bulk carrier using 177 TJ of fuel per year.

Sources: Argus (2025), Argus Direct (Argus Media group, all rights reserved), Official Journal of the European Union (2023), Regulation (EU) 2023/1805 on the Use of Renewable and Low-Carbon Fuels in Maritime Transport, and Amending Directive 2009/16/EC; and IEA (2025), Global Energy and Climate Model.

Meeting post-2030 targets would require more widespread deployment of low-emissions fuels. For instance, achieving the 2035 base target would necessitate nearly 3 EJ of fuels and energy sources emitting under 19 g CO_2-eq/MJ – nearly half of today's global renewable fuel use. Fuels with higher GHG intensities can still qualify but must be used in larger volumes. Improved energy efficiency and reduced oil/coal shipping (from quicker global electric vehicle and renewable electricity expansion) could cut fuel demand by nearly 30% (requiring just under 2.5 EJ), making compliance easier. Meeting the direct target in this scenario would require just under 3.5 EJ of low-emissions fuels and energy sources.

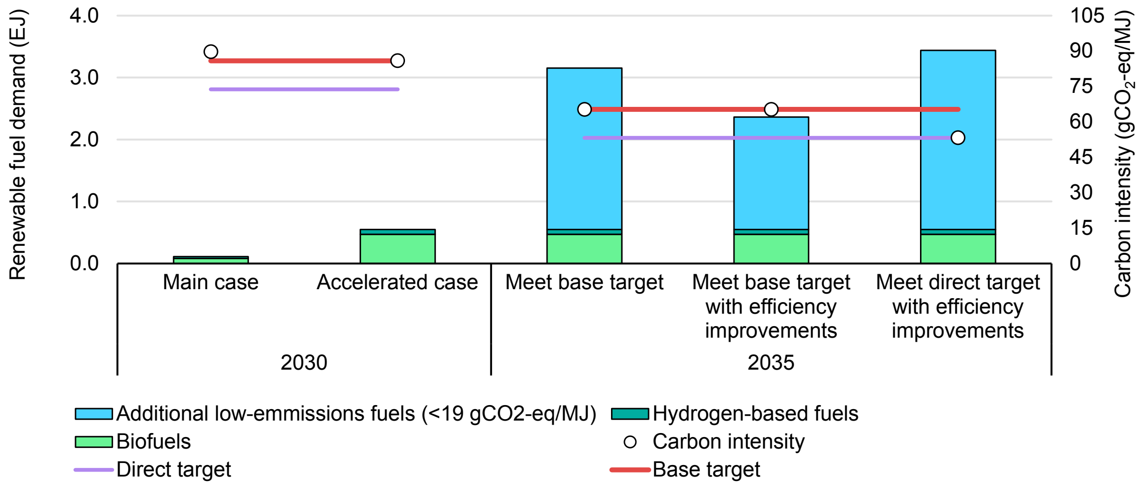
While the IMO global fuel standard can provide stakeholders with a clear long-term demand signal, it also rewards emission reductions and supports a diverse set of technologies and fuel pathways. However, realising its aims will require thoughtful implementation and complementary measures involving energy efficiency targets, innovation support and carbon accounting.

- **Energy efficiency:** Clear long-term energy efficiency targets can reduce compliance costs and total fuel demand. For instance, the IEA estimates that 15% fuel savings are possible for a typical container ship, with a payback period of under five years. The IMO plans to examine efficiency targets and update them by early 2026 in phase 2 of its review.
- **Innovation:** Performance standards are necessary but often insufficient on their own to reduce the risks associated with deploying new technologies such as

hydrogen-based fuels and biofuels derived from woody wastes and residues. Offering targeted financial support – through mechanisms such as contracts for difference, guaranteed pricing and capital investment – can be critical to scale up deployment of these emerging options until they become cost-competitive.

- **Feedstocks:** Liquid biofuels and biomethane are already commercially available, and their use can achieve near-zero – or even negative – emissions intensities, particularly in the case of biomethane. However, deployment at scale will require incentive systems that reward verified GHG reductions. In turn, the effectiveness of these systems will depend on clear and consistent guidance on key carbon intensity determinants such as indirect land use change, agricultural emissions and the recognition of customised emissions pathways.

Renewable fuel demand to mee the proposed IMO Net-zero framework, main and accelerated cases, 2030 and 2035

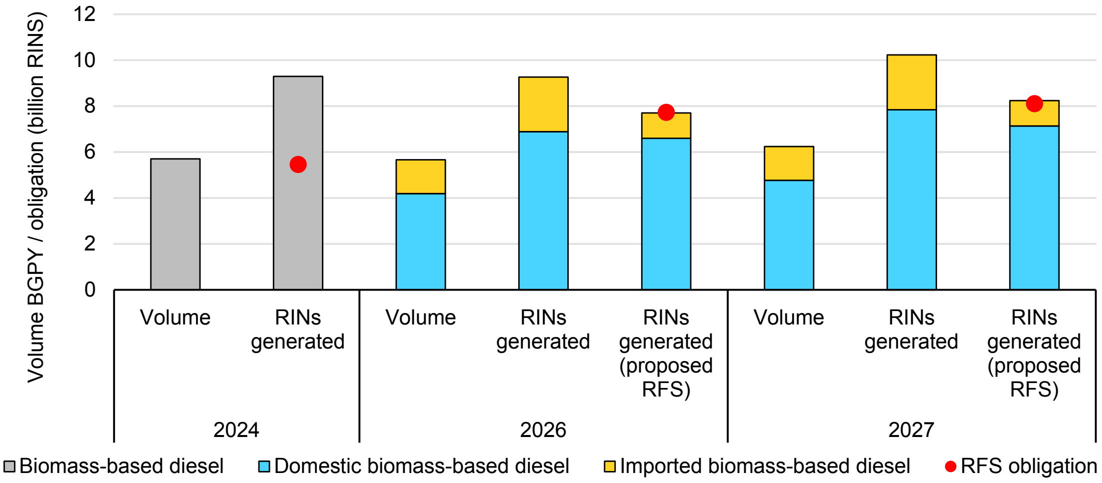


Notes: Total shipping fuel demand estimates to 2035 are based on the IEA World Energy Outlook STEPS scenario for meeting the base target, and on the APS for meeting the direct and base targets with efficiency improvements. Estimates to 2030 assume carbon intensities of 15 g CO_2-eq/MJ for biofuels and 3 g CO_2-eq/MJ for hydrogen-based fuels.
Source: IEA (2024), World Energy Outlook 2024.

US policy changes align supply and demand, favouring domestic feedstocks

In June 2025, the US government proposed an increase to renewable fuel obligations under the RFS; in July 2025 it approved the extension of 45Z tax credits; and in March, April and August 2025 it implemented various import tariffs. The modified RFS and the tax credits both introduce changes that favour domestically produced fuels over imports. These policy shifts are not expected to alter biofuel use significantly from last year's main case forecast, however, as biodiesel, renewable diesel and biojet fuel were already over-complying with the RFS.

Biomass-based diesel and Renewable Identification Number obligations, 2024, 2026 and 2027



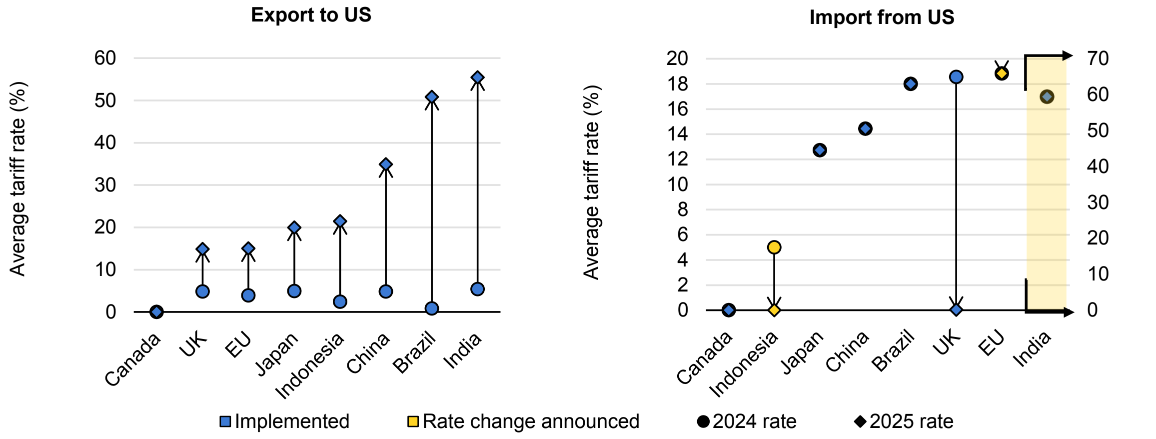
IEA. CC BY 4.0.

Notes: BGPY = billion gallons per year. RIN = Renewable Identification Number. RFS = Renewable Fuel Standard. Former RFS RIN Values = IEA estimates of the RIN value of US biofuel use in the main case when excluding proposed changes to RIN generation for imported fuels and fuels made from imported feedstocks and changes to multipliers for renewable diesel and biojet.
Source: RFS targets from EPA (2025), Proposed Renewable Fuel Standards for 2026 and 2027.

However, the revisions align policy targets more closely with domestic production capacity. Domestic vegetable oil producers stand to benefit the most, while imported SAFs – or those made from imported feedstocks – could lose the majority of their credit value with the lower 45Z tax credit, with proposed changes to feedstock crediting under the RFS rendering them largely uncompetitive in the United States. Overall, we expect the changes to drive up RIN prices, since the United States will continue to rely on some feedstock imports through at least 2027.

The revised RFS increases volume obligations by nearly 10% to 2027, with most growth directed at biomass-based diesel. At the same time, the new rules halve the value of RINs generated from imported fuels or those made with imported feedstocks. This has the dual effect of raising obligations while prioritising domestic feedstocks. While our previous forecast projected the generation of nearly 10 billion RINs in 2026, the new rules would result in around 7.7 billion, equal to the RFS target.

Change in tariff rate (trade-weighted average, ethanol, biodiesel and feedstocks), 2024-2025



Notes: Tariff rates are as of 12 September 2025 and represent the trade-weighted average across the fuels and feedstocks analysed (ethanol, biodiesel, maize, soybeans, canola, rapeseed, corn oil, soybean oil, canola oil, rapeseed oil, tallow and animal fats, used cooking oi, and POME). Weights are determined by each product's share of 2024 exports or imports between the US and selected countries. "Implemented" refers to tariffs in force as of 12 September 2025. "Rate change announced" refers to bilateral agreements that have been announced but not yet implemented, and are therefore subject to change.

Sources: Global Trade Alert (2025), U.S. Tariff Measure Inventory 2025 database (accessed 6 September 2025); World Trade Organization (2025), WTO Tariff and Trade Data; Argus Media (2025) (Argus Media group, all rights reserved), US Biofuels Imports and Exports; The White House (2025), Amendment to Duties to Address the Flow of Illicit Drugs Across our Northern Border; GOV.UK (2025), Update on the UK-US Economic Prosperity Deal (EPD); GOV.UK (2025), Introduction of the New United States Preferential Agreement under the US-UK Economic Prosperity Deal (EPD) - 30 June 2025; The White House (2025), Fact Sheet: The United States and European Union Reach Massive Trade Deal; European Commission (2025), EU-US Trade Deal Explained; The White House (2025), Fact Sheet: President Donald J. Trump Secures Unprecedented U.S.-Japan Strategic Trade and Investment Agreement; The White House (2025), Fact Sheet: The United States and Indonesia Reach Historic Trade Deal; Reuters (2025), Indonesia Still Negotiating Details, Exemptions on US Tariff Deal, Official Says; The White House (2025), Joint Statement on U.S.-China Economic and Trade Meeting in Geneva; The State Council, The People's Republic of China (2025), Joint Statement on China-U.S. Economic and Trade Meeting in Stockholm; and M.Y. and Associates Ltd (2025), Announcement of the Customs Tariff Commission.

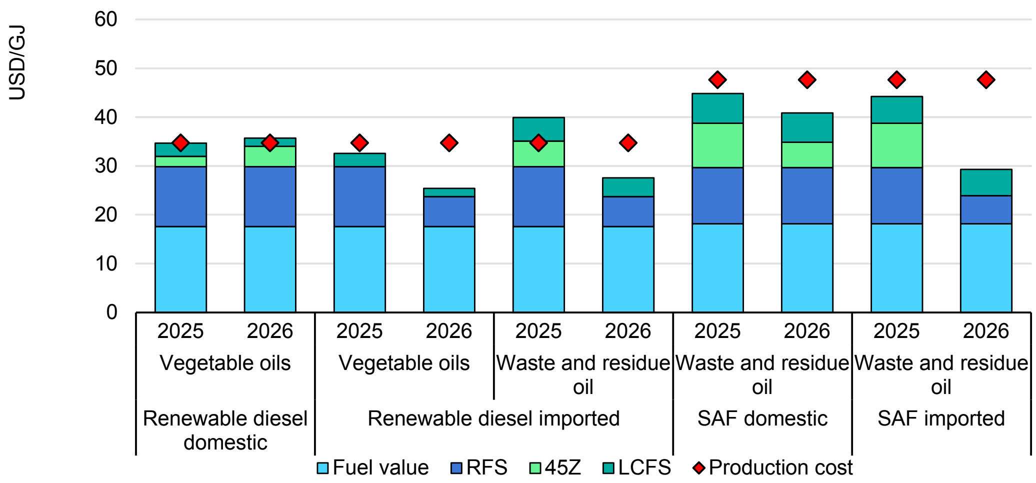
Meanwhile, the OBBBA extends the 45Z clean fuel production tax credits to 2029 but restricts eligibility to fuels made in the United States from North American feedstocks. It also removes the 75% credit premium previously available for SAFs and allows crop-based fuels to qualify for higher credits by removing indirect land use change from the carbon intensity calculation. Clean-fuel credits under the 45Z incentive are awarded based on carbon intensity, with lower intensities receiving higher credits.

In March 2025, the United States began implementing a series of import tariffs that include ethanol, biodiesel and associated feedstocks. Import tariff increases on affected fuels and feedstocks range from 10 to 50 percentage points depending on the country of origin, with the exception of Canada and Mexico, which remain exempt as long as products comply with the United States-Mexico-Canada Agreement (USMCA). Tariff rate changes serve to further strengthen domestic fuel production and domestic feedstock use.

Several countries have also changed or plan to change tariff rates on imports of US biofuels or feedstocks. For instance, the United Kingdom has removed all tariffs on US ethanol up to 1.4 billion litres per year. Indonesia plans to remove all tariffs on biofuels and feedstocks, except for ethanol used in alcoholic beverages. The European Union announced plans to improve access for selected products, including soybeans (subject to tariff rate quotas), but final terms of the agreement had not been released as of September 2025.

Tariff rate changes are only part of the picture, however, as many countries are providing domestic incentives for domestic biofuel use and are negotiating bilateral trade deals. For instance, the White House announced that Japan will purchase USD 8 billion in US agricultural products including corn, soybeans, ethanol and sustainable aviation fuel.

Renewable diesel and sustainable aviation fuel credit value changes and production costs for selected feedstocks, 2025 and 2026



Notes: SAF = sustainable aviation fuel. RFS = Renewable Fuel Standard. LCFS = Low Carbon Fuel Standard. Across all estimates, LCFS credits are USD 100/t CO_2-eq and D4 Renewable Identification Numbers (RINs) are USD 0.94/RIN. 2025 estimates assume a maximum of USD 0.26/litre for the 45Z tax credit for renewable diesel and USD 0.46/litre for SAF, reduced to USD 0.26/litre in 2026. GHG intensity for vegetable oils is based on soybean oil at 23 g CO_2-eq/MJ (core) and 13.26 g CO_2-eq/MJ (with indirect land use change [ILUC]) for the 45Z credit estimates, and 59.36 g CO_2-eq/MJ for LCFS estimates based on average of existing pathways. Fats, oils and grease (FOG) GHG intensity is 16 g CO_2. ILUC values are excluded from 45Z tax credit estimates for 2026. Fuel values are based on market averages for diesel and jet fuel in 2024.
Sources: Argus (2025), Argus Direct market prices (Argus Media group, all rights reserved); GREET (2025), 45ZCF-GREET; EPA (2025), RIN Trade and Price Information; and California Air Resources Board (2025), Current Fuel Pathways.

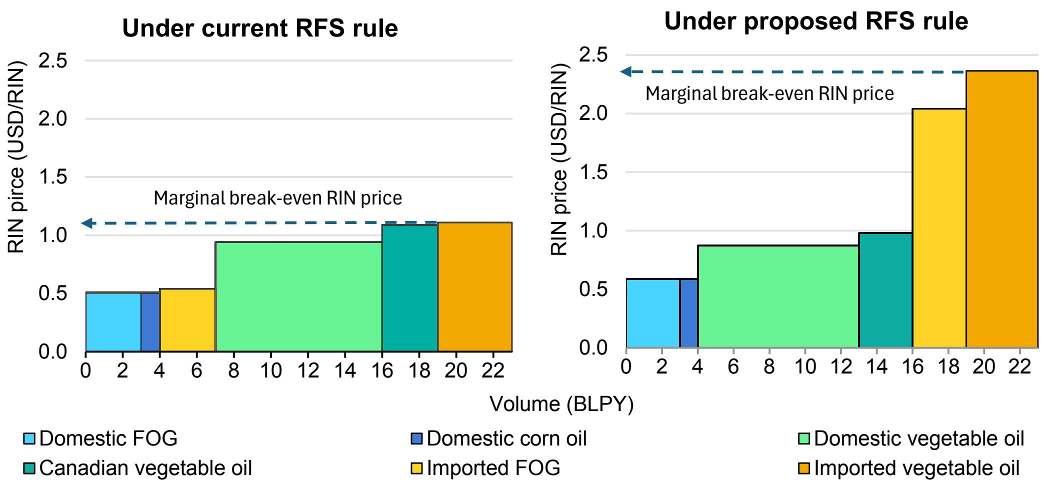
Combined, these measures sharply reduce credit values for imported feedstocks. SAFs made from imported waste or residues lose an estimated 60% of their credit value, while imported renewable diesel loses around 55%. These penalties will likely limit SAF production to airlines willing to pay a cost premium to meet corporate targets, or to export markets such as the European Union. In the European Union or under the CORSIA scheme, US-produced SAFs from waste and residue oils will remain the most viable, since vegetable oil-based SAF is not eligible under RED III and performs poorly in the International Civil Aviation Organization's carbon accounting framework.

Domestic vegetable oil producers could benefit substantially. As of mid-2025, soybean oil futures had risen approximately 15% on the Chicago Board of Trade relative to early 2024. This puts US soybean oil prices 10-15% higher than global averages, based on World Bank and USDA export price indices.

The United States has sufficient biomass-based diesel production capacity to meet its RFS targets through 2027, but insufficient domestic feedstocks – particularly if feedstock imports are discouraged. Even with expanded collection and production efforts across North America, domestic supply gaps are expected.

Canadian and Mexican feedstocks are eligible for full OBBBA credits, but only partial RIN value under the RFS. Regulated parties will therefore still need to import feedstocks, but without full 45Z credits, at half the RIN value and at nearly 10% higher prices on average due to the tariffs. We estimate this could increase compliance costs by around USD 1.25 per RIN, potentially driving RIN prices to nearly USD 2.50/RIN by 2027. Actual values will depend on feedstock prices, LCFS credits and broader energy market conditions.

Biomass-based diesel and Renewable Identification Number price curve required to meet Renewable Fuel Standard obligations, 2027



Notes: RFS = Renewable Fuel Standard. RIN = Renewable Identification Number. FOG = fats, oils and grease. MLPY = million litres per year. Calculations are based on the RIN price needed to break even on production costs, consistent with meeting proposed RFS advanced biofuel 2027 volume requirements (excluding the cellulosic volume requirement) in 2027. The left graph reflects the current 45Z tax credits and RFS. The right graph represents proposed RFS amendments and 45Z changes that go into force in 2026.

Sources: Argus (2025), Argus Direct market prices (Argus Media group, all rights reserved) ; GREET (2025), 45ZCF-GREET; EPA (2025), RIN Trades and Price Information; and California Air Resources Board (2025), Current Fuel Pathways.

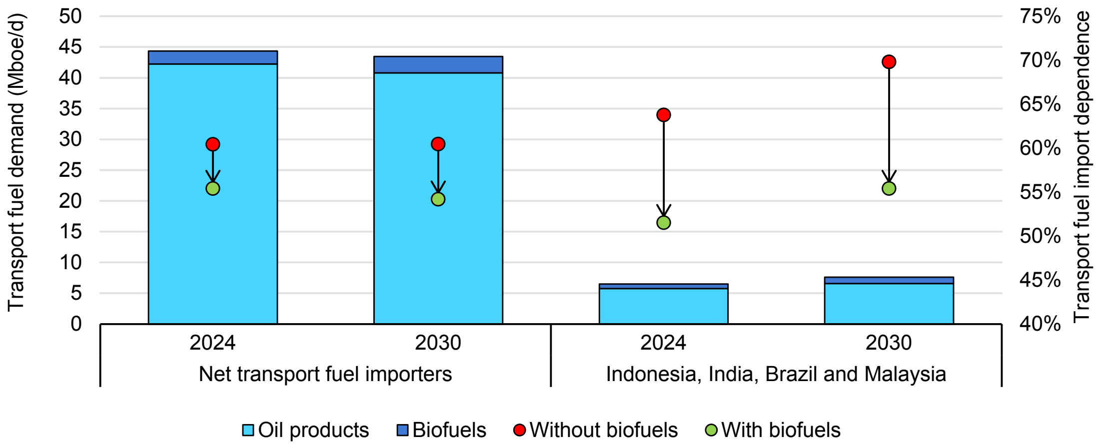
US vegetable oil supply expands over the forecast, but additional production capacity is needed to avoid imports. As of [July 2025](), five new soybean crushing facilities were under construction across the United States, representing over 5.6 million tonnes of additional vegetable oil production capacity to 2027, which we estimate will displace nearly 3 billion litres of fuels made from imported feedstocks. Replacing all biofuel feedstock imports in 2027 with domestic production would require diverting an additional 10% of US and Canadian vegetable seed exports, or almost 6 million tonnes of additional crush capacity.

Biofuels and energy security

Biofuel use reduces transport fuel import dependence

On average, net-transport-fuel-importing countries globally relied on imports for over 55% of their oil demand in 2024, compared with 60% in the scenario in which no biofuels were consumed. For certain countries, the impacts of using biofuels are more significant: for instance, Brazil realises a 24-percentage-point decrease in import dependence. In Indonesia, India, Brazil and Malaysia (some of the world's fastest-growing transport fuel demand markets), rising biofuel mandates curb import growth. In these four countries, oil import dependence is projected to increase just 6% from 2024 to 2030, even though fuel demand rises 18% during this period.

Transport fuel import dependence with and without biofuels, main case, 2024 and 2030

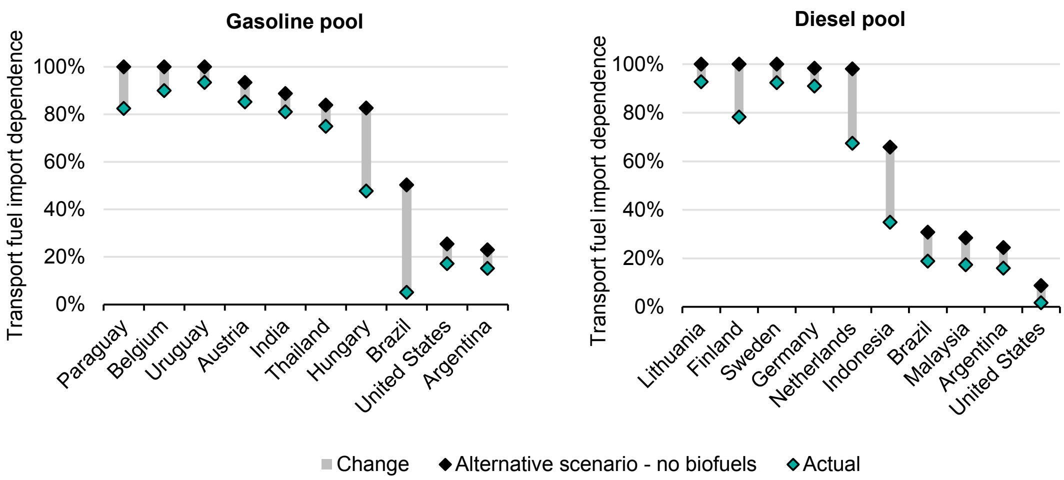


Notes: Transport fuel dependence is calculated as total net imports of oil products (gasoline, diesel and jet fuel), net imports of crude for domestically refined oil products, and net imports of biofuels (ethanol, biodiesel, renewable diesel and biojet) divided by the total final consumption of biofuels. The counterfactual scenario assumes that all biofuel consumption in the given year is directly replaced with imported oil products.
Source: IEA (2025), [Oil 2025]().

The impacts of biofuels on transport fuel import dependence vary by country as well as by fuel type. For gasoline, Brazil experiences the most significant impact, achieving a 45-percentage-point decrease in import dependence (nearly eliminating the need for gasoline imports) through a combination of mandates, fiscal support, GHG intensity reduction targets and the use of flex-fuel vehicles that can operate on higher ethanol blends.

Meanwhile, Indonesia reduces its diesel import dependence by 31-percentage-points through two primary policy mechanisms designed to decrease diesel imports and boost biodiesel consumption: a biodiesel mandate that enforced minimum blending of 40% in 2025, and a subsidy covering the price difference between biodiesel and conventional diesel, ensuring that biodiesel remains economically competitive.

Transport fuel import dependence with and without biofuels for selected countries by fuel type, main case, 2024



Notes: Transport fuel dependence is calculated as total net imports of oil products (gasoline, diesel and jet fuel), net imports of crude for domestically refined oil products, and net imports of biofuels (ethanol, biodiesel, renewable diesel and biojet) divided by the total final consumption of biofuels. The counterfactual scenario assumes that all biofuel consumption in the given year is directly replaced with imported oil products.

Source: IEA (2025), Oil 2025.

For most countries, reductions in import dependence remain modest, typically ranging from 5 to 15 percentage points. Technical constraints, feedstock availability, and cost continue to inhibit higher blending. In Europe, for example, the Fuel Quality Directive caps ethanol blends at 10% by volume. France supports E85 fuel use, but uptake is limited by the low number of compatible vehicles. Similarly, in the United States, blending remains at just under 10% despite financial support for higher-blend infrastructure and ample feedstock availability. In Sweden, GHG intensity targets were reduced from 30% to 6% in 2024 to limit consumer fuel costs. Although average feedstock import dependence remains low (see the next section), domestic supply constraints have slowed biodiesel expansion in India and ethanol blending in Indonesia.

In both the United States and Europe, rising feedstock imports to make biodiesel, renewable diesel and biojet fuel have prompted efforts to diversify and secure domestic supplies. Higher blends remain feasible in many countries, but co-ordinated long-term strategies are required to expand feedstock availability, production capacity and infrastructure while maintaining affordability and supply security.

Feedstock import dependence remains low for ethanol but is rising for biodiesel, renewable diesel and biojet fuel

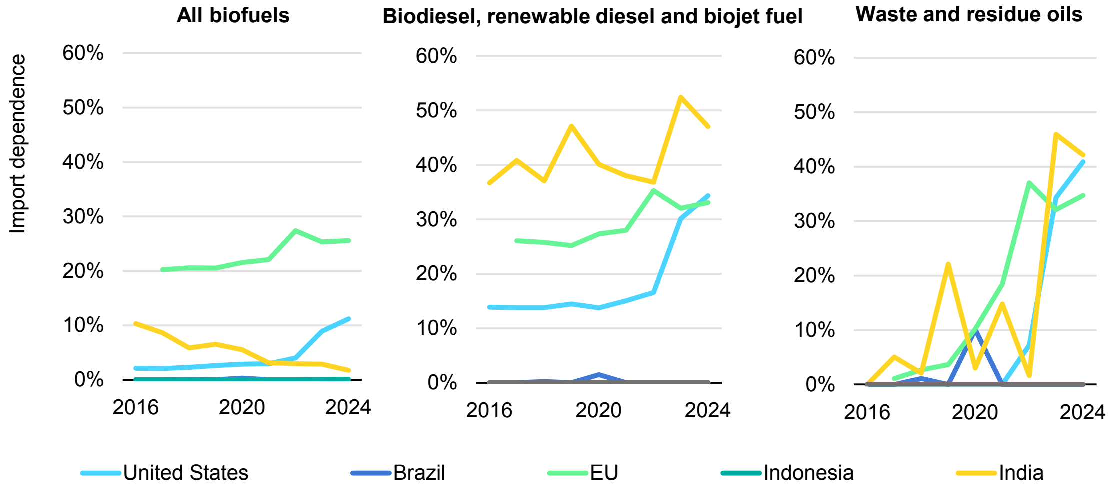
In most major biofuel markets, feedstock import dependence remains low, averaging just under 10% in 2024. For example, ethanol is produced almost entirely from domestic feedstocks in the United States, Brazil, India and the European Union. However, growing demand for biodiesel, renewable diesel and biojet fuel is outpacing growth in the availability of domestic feedstocks (especially waste and residue oils in the European Union and the United States), prompting a rise in imports.

Most biofuel policies are rooted in energy security and agricultural development, and biofuel support programmes were implemented only if domestic feedstocks were available. Many countries further protect domestic agricultural production through import tariffs, quotas or duties. For maize, for instance, India has a 50% import tariff, Brazil a 7% tariff and the United States a fixed rate of US cents 0.05 to 0.25/kg depending on the type of corn, with exemptions for certain trading partners. In practice, these policies encourage domestic biofuel production based on local feedstocks.

Feedstock import dependence remains low for biodiesel in countries such as Indonesia and Brazil, where production is closely linked to domestic feedstock availability and blending rates are adjusted based on local supplies and cost. In the United States and the European Union, however, rapid growth in renewable diesel and biojet fuel production capacity – combined with support for low-carbon-intensity feedstocks – has driven demand to exceed domestic feedstock supply availability.

Since 2020, waste and residue oil imports in Europe and the United States have increased twentyfold, with nearly 60% of the supply coming from China and Indonesia. The United States, a net exporter of waste and residue oils in 2021, is now a net importer. The scale and pace of expansion of these imports have raised concerns about supply fraud.

Biofuel feedstock import dependence, main case, 2016-2024



Notes: Feedstock import dependence is calculated as net imports divided by total domestic feedstock use for biofuel production based on the energy value of the fuels produced. Vegetable oil figures reflect trade in oils (e.g. soybean oil), not raw crops. Values for net imports of agricultural products are from the OECD, values for net imports of waste and residue oils are from Kpler and values for domestic demand are from the IEA.

Sources: OECD/FAO (2024), OECD-FAO Agricultural Outlook 2024-2033; and Kpler (2025), World Monthly Exports, Biofuels.

In response, both the United States and the European Union have introduced oversight measures. The European Commission has launched a Union Database for Biofuels to improve traceability, prevent double counting and reduce the risk of fraud. ISCC, the main international certification scheme, has updated its audit procedures, lowering thresholds for residue oil audits and suspending certificates for over 130 companies.

In the United States, California plans to require sustainability certification for fuels used under its updated Low Carbon Fuel Standard. Federally, the proposed RFS updates halve the value of credits for fuels produced from imported feedstocks. The OBBBA further eliminates tax credits for imported biofuels and biofuels made from imported feedstocks, except for those sourced from Canada and Mexico.

In general, biofuels have helped reduce import dependence and are predominantly produced from domestic feedstocks – and this pattern is expected to persist in most markets throughout the forecast period. In our accelerated case, however, biofuel demand expands more than 60% by 2030 compared to 2024. Trade – whether in fuels, feedstocks or sustainability claims – could help facilitate this growth.

Provided that robust certification systems are in place to ensure supplies are sustainable and verifiable, an effective trading system can advance domestic energy security, affordability, development and decarbonisation goals. Relying on a diverse set of trading partners can reduce exposure to imported feedstock or fuel supply risks.

Additional efforts are also needed to diversify low-emission feedstock sources and production techniques. In fact, one of the key reasons for both rising imports and supply chain fraud is the global tendency to concentrate on a narrow set of feedstocks – particularly waste and residue oils (see the feedstock focus section above).

Chapter 3. Renewable heat

Heat is the primary form of end-use energy globally, making up almost half of total final energy consumption. Industry is responsible for up to 55% of total heat demand, buildings for 42% (for water and space heating, and cooking), and agriculture claims the remainder, using mostly modern bioenergy and geothermal energy for drying, greenhouse heating, fish farming and other activities. The heat sector therefore deserves more visibility and political support, especially since renewable energy technologies are already commercially available.

In 2024, modern renewables met around 14% (nearly 30 EJ) of global heat demand. Although renewable heat supply has expanded, mainly through the replacement of traditional uses of bioenergy, its growth has historically been modest and not fast enough to keep pace with growing heat demand, which continues to be met largely with fossil fuels. However, volatile fossil fuel prices, recent energy price inflation, growing consumer awareness and energy security concerns are spurring greater interest in local renewable heat solutions, raising its share globally through 2030.

Recent global and regional trends and policy updates

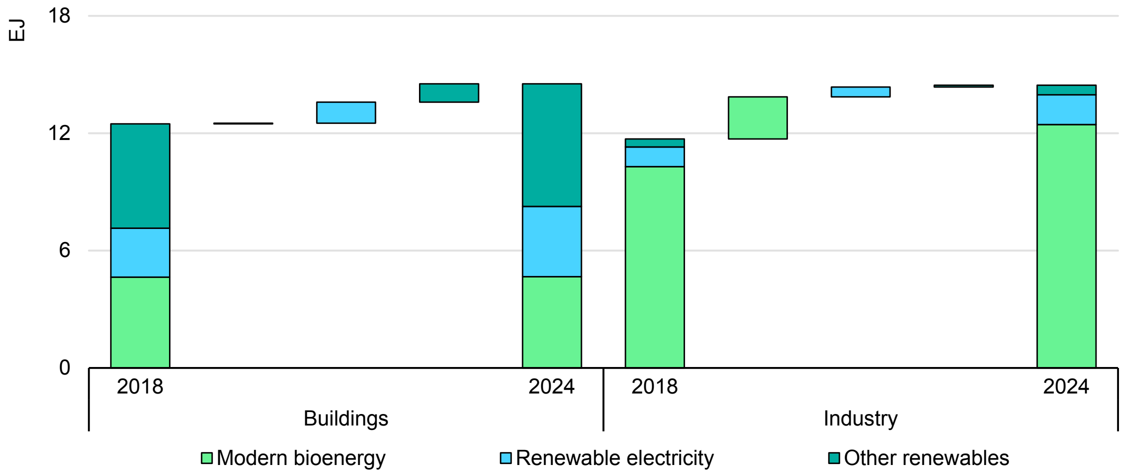
Between 2018 and 2024, global annual heat demand increased 6% (+12 EJ), largely driven by economic and industrial growth in emerging economies. Broader global trends such as building stock expansion, relatively slow efficiency improvements, changing demographics and comfort expectations also played a role. The demand from modern renewables continued to rise by over 6 EJ (out of a 12-EJ increase in heat demand), representing half of total growth, while the use of traditional biomass decreased 5% (-1 EJ). Annual heat-related CO_2 emissions rose by more than 0.5 Gt CO_2 to almost 14 Gt CO_2, accounting for 37% of global energy-related CO_2 emissions. The increase in CO_2 emissions came almost entirely from industry, reflecting the sector's ongoing dependence on fossil fuels for heat.

Modern bioenergy continued to dominate renewable heating at 21% (+3 EJ) growth, almost entirely in the industry sector. However, renewable electricity was the fastest-growing renewable heat source: since 2018, its consumption has risen 55% owing to a surge in the use of electric heaters, boilers and especially heat pumps, expanding much more quickly than overall global energy demand. Electricity use for heating – along with a growing share of renewables in the power mix – is becoming a key global driver in the decarbonisation of heat, especially in buildings and, increasingly, in industry.

In 2024, new solar thermal installations fell by 14% globally. For the first time, global installed capacity declined as new additions could not offset retirements of plants built in the early 2010s. This decline was driven by competition from other technologies, including heat pumps, direct-use geothermal and rooftop solar PV, and by an ongoing slowdown in construction activity in China (-17%), the largest market for solar thermal installations. Further declines were seen in Poland (-43%), Germany (-42%), Italy (-36%), the United States (-31%), Spain (-30%), Greece (-26%), India (-24%) and Australia (-16%), mostly due to favourable policies and government programmes for competing technologies. However, four countries experienced growth: Brazil (+11% owing to construction sector expansion), Mexico (+14%, driven by industrial needs for lower energy costs and improved energy security), Türkiye (+10%) and Cyprus (+2%).

Although geothermal heat use by individual systems grew 48% over the period, it still accounts for less than 1% of total renewable heat consumption. In 2024, there was a surge in announced geothermal projects for both heat and power, particularly in the United States, Southeast Asia and parts of Europe.

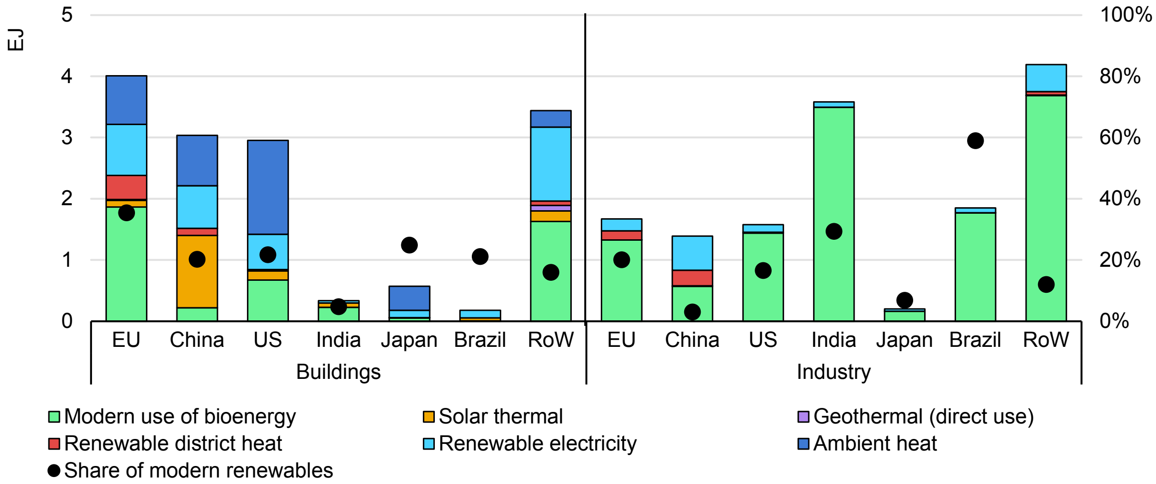
Changes in the use of modern bioenergy, renewable electricity and other renewables in buildings and industry, 2018 and 2024



Notes: “Other renewables” includes solar thermal, geothermal, district heating and, in the case of buildings, ambient heat harnessed by heat pumps. Ambient heat from heat pumps is not accounted for in the industry sector due to limited data availability.
Source: IEA (forthcoming), World Energy Outlook 2025.

District heating systems increasingly feature a more diverse mix of technologies, including large-scale heat pumps, waste heat recovery, solar thermal and geothermal, and have expanded notably in China and Europe. Government policies, greater use of thermal storage and a broader shift towards cleaner multi-source heating networks spurred this growth.

Modern renewable energy use and shares of renewable heat demand in selected regions, 2024



Note: RoW = rest of world.
Source: IEA (forthcoming), World Energy Outlook 2025.

The use of cascade heating, an industry practice that reuses high- and low-temperature heat in stages from multiple sources including heat pumps, geothermal, solar thermal and waste heat, is set to expand in district heating networks and industry. Policy support is helping this practice gain traction: in the European Union, the Energy Efficiency Directive promotes waste heat integration into district heating, while China uses cascade heating systems in heavy industry, particularly steel, and in eco-industrial parks under its broader circular economy agenda. Meanwhile, India encourages waste heat recovery through its Energy Conservation Act and the Perform, Achieve and Trade (PAT) scheme. In the United States, several industrial projects using cascade heating were cancelled in early 2025 after the termination of federal support programmes.

Policies and initiatives to scale up renewable heating deployment

Although global efforts to scale up renewable heating are advancing thanks to diverse policy approaches, progress remains uneven across regions and sectors and continues to lag behind power sector developments. While stronger policy support is beginning to address economic barriers, including the higher upfront costs of renewable energy systems compared to fossil-based alternatives, persistent challenges include funding limitations for end users and insufficient infrastructure (e.g. grid connections and heat networks). Furthermore, data and monitoring gaps continue to make it difficult to track progress and scale up successful approaches.

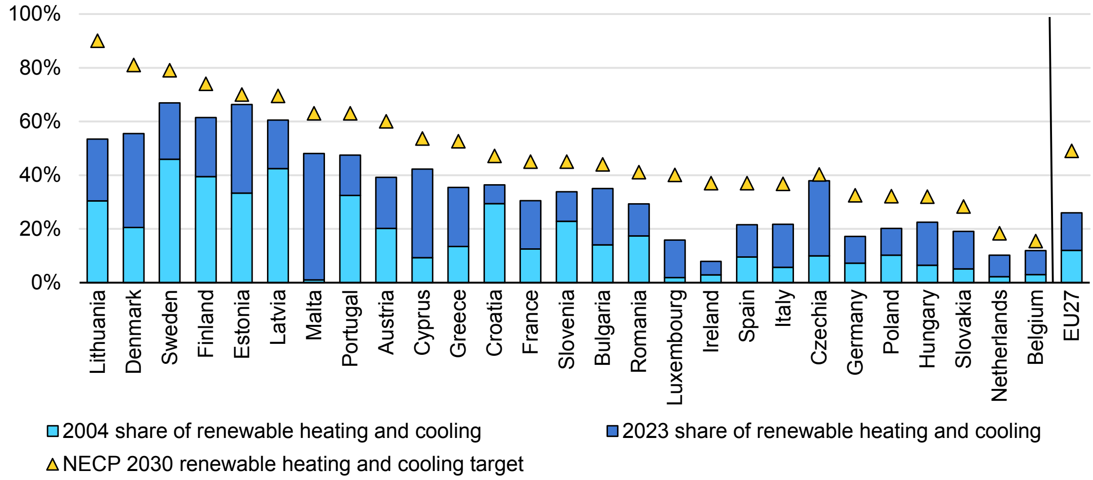
The European Union leads efforts to expand renewable heating through supportive regulations, including fossil-based heating bans; stricter building rules; generous funding mechanisms; and binding RED III targets that require an annual 1.1-percentage-point increase in the share of renewables in heating and cooling starting in 2026. The new Emissions Trading System (ETS) 2 (adopted in 2023 and set to be operational in 2027) will incentivise low-carbon heating in buildings by pricing emissions from fossil fuel use, complementing RED III goals, and will channel revenues to the Social Climate Fund to support vulnerable groups.

The Clean Industrial Deal, and its EUR 100-billion industrial decarbonisation bank, will prioritise electrification and support renewable industrial heat through the world's first heat auction in 2025 (EUR 1-billion budget) and relaxed state aid rules. Individual European countries also continue to provide state-level financial support for the use of low-carbon technologies in the buildings and industry sectors. Grid connection barriers are being addressed, and the European Council is calling for faster geothermal deployment and easier access to financing.

The 2024 National Energy and Climate Plans (NECPs) include renewable heating and cooling targets, though ambitions vary widely. On average, the European Union is aiming for a 49% renewable energy share in heating and cooling by 2030, with the largest relative increases to be achieved by Ireland, Luxembourg and Germany. Sweden, Latvia and Estonia, which are already above 60%, show more modest growth due to their advanced starting point.

While NECPs are national, heating and cooling challenges are largely local. To better align national goals with local realities, the Energy Efficiency Directive is requiring member states to develop local heating plans starting in October 2025. These plans should map local heat demand, renewable energy potential and waste heat sources. Integrating them into NECPs can help connect national-level planning with local implementation. The upcoming EU Heating and Cooling Strategy, expected in early 2026, is expected to send a stronger political signal to member states on the urgency of decarbonising heating and promoting all renewable heat sources.

Share of renewables in heating and cooling, 2004-2023, and NECP 2030 targets for EU27 and member states



Notes: NECP = National Energy and Climate Plan. Austria has a legislative target that is neither WEM (with existing measures) nor WAM (with additional measures). WEM applies to Denmark, Estonia, Finland, France, Germany and the Netherlands; the remaining countries are WAM.

Sources: Eurostat SHARE database (accessed 11 September 2025); European Commission (2025), National Energy and Climate Plans.

The United States made major changes to clean-heat support in 2025. A January executive order cancelled several grant, loan and demonstration programmes, as well as tax credits for solar water heaters, heat pumps and electric boilers. Then, in July the One Big Beautiful Bill accelerated the phase-out of residential geothermal tax credits, which will end in December 2025, while commercial geothermal credits will remain until 2034 and be gradually phased out to zero thereafter. This bill also introduced stricter foreign content rules under the Foreign Entity of Concern (FEOC) policy. Meanwhile, the EPA GHG Reduction Fund, which supported energy efficiency and heat pump deployment in low-income communities, was discontinued in March 2025.

Despite the funding freeze, utilities and states in parts of the Northeastern and Western United States continue to promote clean heating. Ten states[8] and Washington DC have pledged to raise residential heat pump sales to 65% by 2030 and 90% by 2040 and released a draft action plan in September 2025. New York launched a USD 5-billion energy efficiency and building electrification programme in May 2025, while California continued to fund industrial decarbonisation in 2024 and 2025 through the INDIGO (Industrial Decarbonization and Improvement of Grid Operations) programme and FPIP (Food Production Investment Program).

In other parts of the world, China is accelerating heat pump development and intensifying activities under its Coal-to-Electricity campaign, including coal boiler

[8] California, Colorado, Maine, Maryland, Massachusetts, New Jersey, New York, Oregon, Rhode Island and Washington.

phase-out (with provinces providing support for rural areas), while Japan has launched a programme to provide subsidies for renewable heat and waste heat recovery. Countries such as Canada, Australia, New Zealand and emerging markets in Africa, Asia, Latin America and the Middle East are expanding incentives and piloting diverse renewable heat technologies, but progress varies widely.

District heating systems worldwide rely increasingly on mixed solutions such as solar thermal, geothermal, heat pumps and waste heat, and deployment is being driven by policies and financial incentives geared towards decarbonisation. For example, Dubai is advancing renewable heat use through large-scale solar thermal and geothermal energy trials for district cooling through absorption chillers.

Recent heat-related policy developments

Country	Development
Australia	Incentives (December 2024) for heat pumps and solar thermal have been expanded under long-running small-scale renewable energy schemes (SRES), primarily at the state level in Victoria and New South Wales, but requests to further include electrification are intensifying.
Brazil	Calls were launched (June 2024) to upgrade water heating systems in public buildings.
Brazil São Paolo	A new law (December 2024) mandates the installation of solar water heating in certain new buildings.
Canada	The Oil to Heat Pump Affordability (OHPA) Program and the Canada Greener Homes Initiative increased support for clean heating technologies through grants and rebates for heat pumps, including in Ontario and the Yukon.
China	The State Council (May 2024) introduced a phase-out of some coal-fired boilers and facilities by 2025.
China	The National Development and Reform Commission (October 2024) encouraged the rollout of renewable energy heating technologies.
China	A Heat Pump Action Plan was adopted (April 2025) to target heat pump industry development and deployment.
China	Throughout 2024, Beijing and Shaanxi strengthened standards to support rural clean heating programmes and introduced financial incentives to help speed up the transition.

Country	Development
European Union	RED III set binding targets for renewable heating and cooling as of 2026, alongside indicative targets for industry, district heating and buildings.
European Union	Under the EPBD, the European Commission offered guidance on phasing out financing for stand-alone fossil fuel boilers from October 2025.
European Union	European Council Conclusions (December 2024) called for faster geothermal deployment, streamlined permitting, easier access to financing and establishment of a European Geothermal Alliance.
European Union	The European Union agreed to ban new fossil fuel heating units by 2040 and subsidies as of 2025.
European Union	The Clean Industrial Deal (February 2025) introduced a 32% cross-economy target for 2030.
European Union	The Clean Industrial Deal State Aid Framework (June 2025) granted support for renewable heating and cooling across industry, buildings and district heating through grants, tax incentives and derisking mechanisms.
European Union	The Energy Efficiency Directive requires member states to develop local heat plans as of October 2025 and promotes cascade heating in district heating.
European Union	The Innovation Fund's first EUR 1-billion heat auction for industrial heat is scheduled for late 2025 (the exact rules are currently being finalised) under the Industrial Decarbonisation Bank.
European Union	The European Agency for the Cooperation of Energy Regulators recommended (December 2024) that the HVDC Network Code be amended to facilitate grid connection for industrial consumers.
France	France extended grants to phase out fossil fuel boilers (December 2024), revamped the MaPrimeRénov' scheme to replace old heating systems with renewables (September 2025), offered bonuses for renewable heat, expanded the budget and introduced new tools under the Fonds Chaleur programme and invested in district heating networks around the country.
Germany	The Revised Building Energy Act and new Local Heat Planning Act (August 2024) require municipalities to plan heat networks with 30% renewables by 2030 and 100% by 2045, and building owners to use renewable heating.
Japan	The government introduced a subsidy programme (April 2025) to lower the deployment costs of renewable heat technologies (e.g. biomass boilers and heat pumps) and industrial waste heat recovery systems.
The Netherlands	The Municipal Instruments Heat Transition Act (March 2025) mandates that local governments shift from natural gas to sustainable alternatives by 2049.
The Netherlands	The Authority for Consumers and Markets introduced (November 2024) a broad set of measures to unlock unused grid capacity.
New Zealand	The Warmer Kiwi Homes programme (April 2024), which provides grants for insulation and energy-efficient heating (mainly heat pumps) for low-income households, was updated and significantly expanded to now include middle-income households.

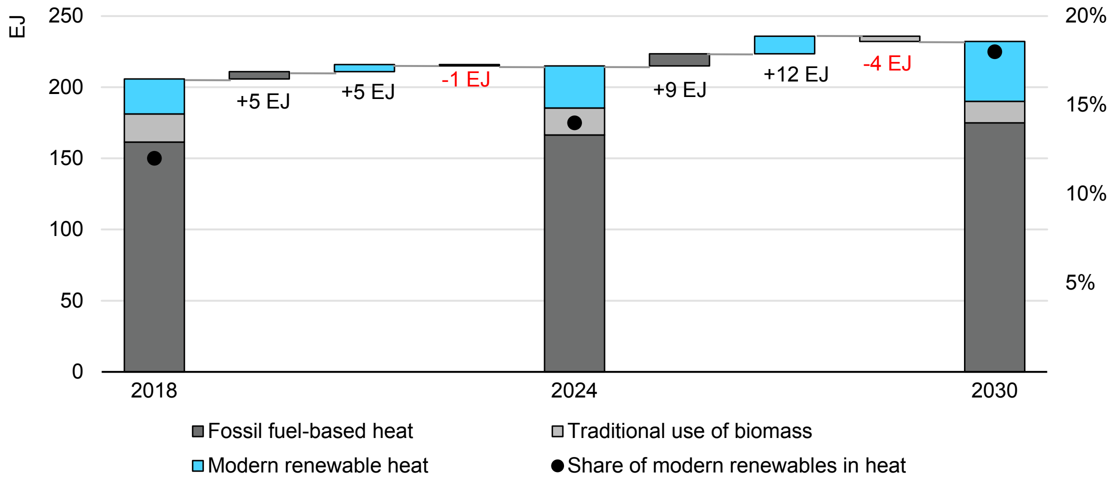
Country	Development
New Zealand	The From the Ground Up draft strategy (July 2025) aims to double the use of geothermal energy for power and direct heat by 2040. It is currently under consultation.
United Kingdom	The government announced (November 2024) plans to double funding for residential heat pump uptake.
United States	Ten US states and Washington DC (February 2024) committed to increase residential heat pump sales to 65% by 2030 and 90% by 2040. In April 2025, they released a draft action plan to align programmes, co-ordinate data and track market progress.
United States	The Executive Order Unleashing American Energy (January 2025) cancelled several clean-energy grants and loan programmes and cancelled tax credits for solar water heaters, heat pumps and electric boilers.
United States	The EPA discontinued the GHG Reduction Fund (March 2025) for energy efficiency and heat pump deployment in low-income communities.
United States	Measures were taken by system operators in California (May 2025) and New York (June 2025) to support load growth due to industry electrification.
United States	The One Big Beautiful Bill Act (June 2025) accelerated the phase-out of tax credits for geothermal heat pumps and introduced stricter foreign-content rules under the FEOC policy.
Viet Nam	The updated Power Development Plan (2021-2030) (April 2025) explicitly includes renewable heat (biomass, biogas and solar energy) and waste heat recovery and cogeneration.
Viet Nam	The new retail electricity pricing framework (April 2024) sets minimum and maximum retail prices to enable heat electrification.

Outlook for 2030

Between 2025 and 2030, global annual heat demand is projected to rise 8% (+17 EJ), and heat production from modern renewable energy sources is expected to expand significantly, by nearly 42% (+12 EJ). Despite this strong growth, modern renewables will still meet only around 18% of total heat demand by 2030, up from 14% in 2024. This highlights the need for continued efforts to accelerate the transition to cleaner heating solutions.

Traditional biomass use is set to decline 26%, with its share in heat demand falling from 10% in 2024 to 7% in 2030. This trend is largely driven by China's policies to reduce CO_2 emissions, replace inefficient residential biomass stoves with cleaner alternatives, promote electrification and expand access to district heating. In the buildings sector, the rising use of modern renewables will fully offset declines in both traditional biomass and fossil fuels. Annual heat-related CO_2 emissions are expected to increase by nearly 0.6 Gt CO_2, reaching almost 14.6 Gt CO_2 by 2030. This increase stems almost entirely from the industry sector (+11%), while CO_2 emissions from buildings continue to decline (-7%).

Changes in the use of modern renewables, traditional biomass and fossil fuels in global heat demand, and the share of modern renewables in heat, 2018, 2024 and 2030



Source: IEA (forthcoming), World Energy Outlook 2025.

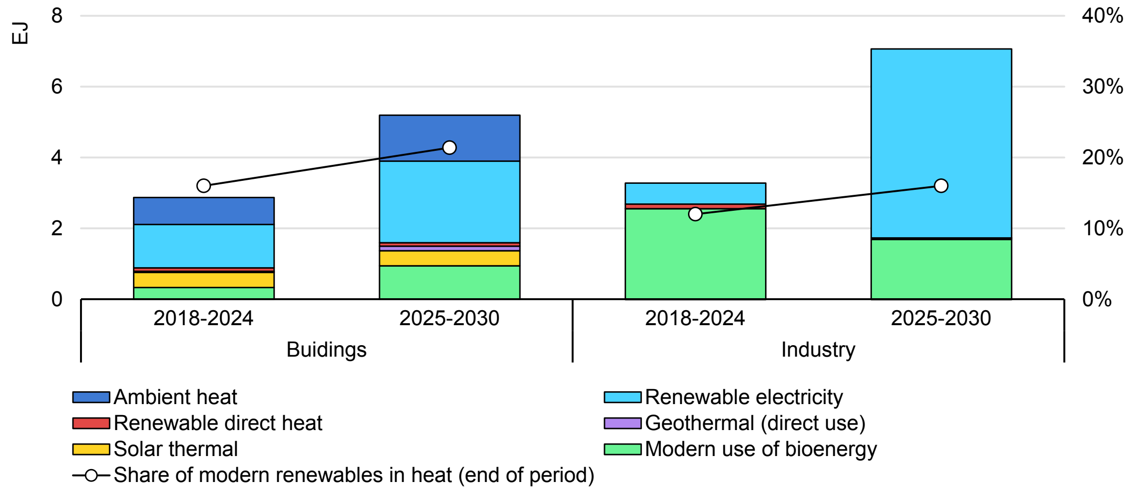
By 2030, industry is expected to become the dominant heat consumer, with renewable heat use climbing 49%. China and India will make up nearly 60% of this growth. In China, heat demand met with renewables is set to double, supported by strong government policies. These policies are expected to almost quadruple the use of renewable electricity for heating, so that electricity accounts for more than half of China's total renewable heat consumption in 2030.

Globally, renewable electricity consumption for heating is set to grow 2.5 times, and the use of ambient heat from heat pumps will rise by one-third thanks to strong policies in China and the European Union and the high efficiency of heat pumps, which can deliver four to five times more heat than the electricity they use, making them a powerful solution for low-emissions heating.

Affordability is also a key driver. In regions with significant heating (and cooling) needs, such as the southern United States or central China, heat pumps are gaining traction even without subsidies, simply because they are an affordable solution.

If all announced projects materialise, geothermal heat use in buildings is set to more than double to 250 PJ, driven by expanding project pipelines, policy support and drilling technology advances in markets in the United States, Southeast Asia and parts of Europe. Solar thermal heat consumption is also expected to increase (+29%), especially for district heating applications in Europe, with policies supporting their integration into urban heating and cooling networks.

Global increases in renewable heat use, 2018-2030



Source: IEA (forthcoming), World Energy Outlook 2025.

Buildings

Water and space heating and cooking with renewables currently account for 42% of global buildings sector heat demand, a share that is expected to decline slightly to just under 40% by 2030 as industrial heat demand climbs at a faster rate. Worldwide, heat demand in this sector is stabilising, having grown only 2% since 2018 and projected to rise just 1% by 2030, largely due to increased adoption of energy-efficient technologies and the expanding use of renewables. In 2030, China, the European Union, India and the United States together account for around half of global heat demand for buildings, while 20% comes from Russia, sub-Saharan Africa (particularly for cooking) and the Middle East.

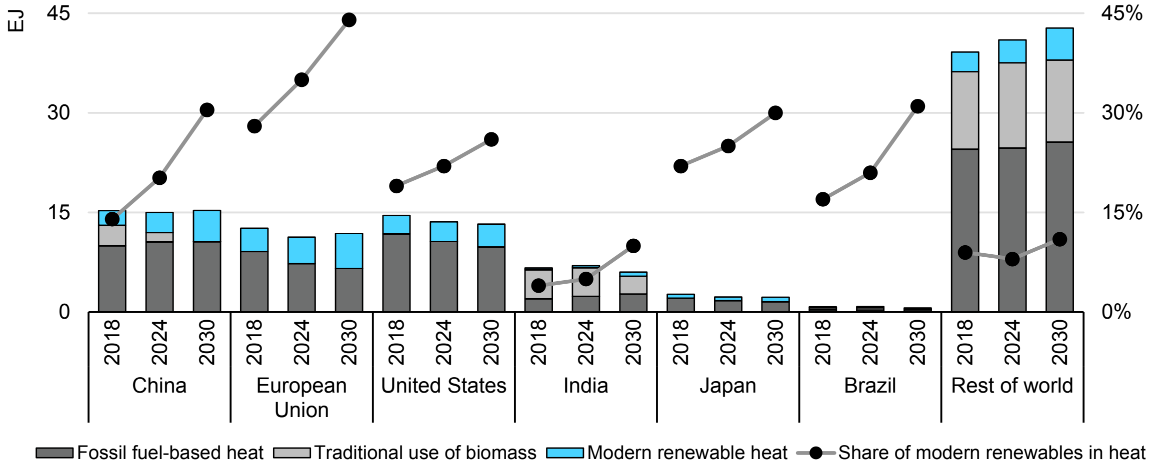
The energy mix for building heating is changing. While traditional biomass use currently provides 21% of heat for buildings, this portion is projected to fall to 16% by 2030, while the share of modern renewables is set to grow from 16% to 21%. The shrinking use of non-renewable energy sources (expected to decline from 84% today to 79% in 2030) will change the buildings sector's contribution to energy-related CO_2 emissions.

Although traditional biomass use is dropping overall, it is set to increase by 2030 in sub-Saharan Africa (excluding South Africa) (+2%) and the Middle East (+8%), particularly in rural areas. This trend results from ongoing challenges surrounding affordability and energy access, especially for cooking.

Between 2018 and 2024, modern renewable heat use in the buildings sector grew 25%, and it is set to rise even more quickly to 2030 (+36%).

Since 2018, modern bioenergy growth has been slow (+8%), but it is set to increase 20% by 2030. Several countries and regions are expected to experience growth, particularly Brazil (+104%), sub-Saharan Africa (+57%) and China (+49%), while declines are projected for Japan (-9%) and the United States (-8%).

Increase in heat consumption in buildings and share of renewables in heat demand in selected regions, 2018-2030



IEA. CC BY 4.0.

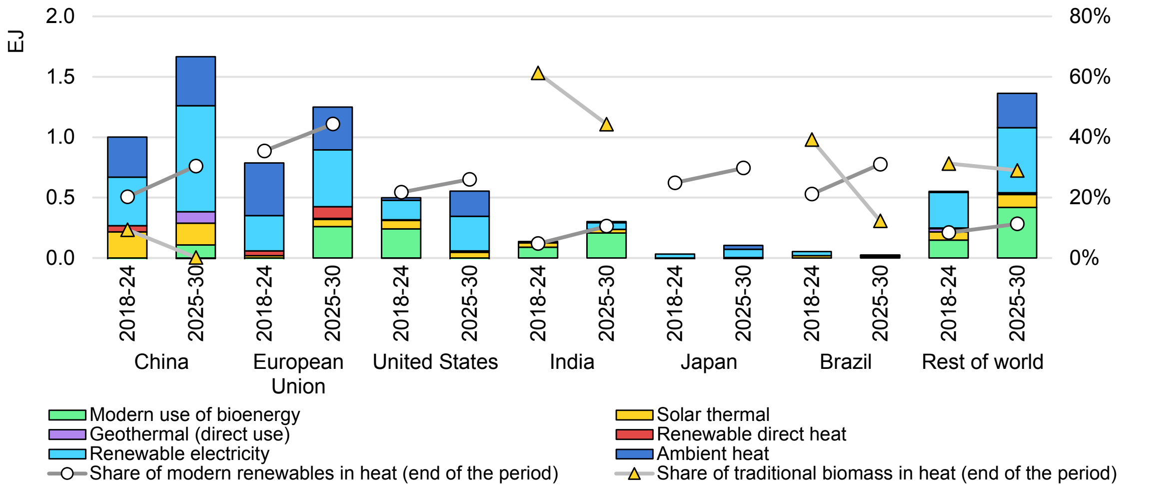
Source: IEA (forthcoming), World Energy Outlook 2025.

In Brazil, modern bioenergy use is expanding in urban cogeneration and district bioheat, especially near sugarcane clusters and biogas projects in São Paolo, Mato Grosso and Rio de Janeiro. By December 2026, Brazil plans to add 20 more plants with a total capacity of 11 PJ/year, driven by the 2024 Fuel of the Future bill and its biomethane blending mandate of 1% by 2026 and 10% by 2036.

In sub-Saharan Africa, heat production is dominated by traditional biomass. Bioenergy remains the primary modern renewable energy source, accounting for over 90%. Its demand is set to nearly double by 2030 with wider adoption of improved biomass cookstoves, which are gradually replacing traditional biomass use. In China, retrofits of rural homes with pellet stoves and the integration of biogas for combined cooking and heating continue to scale up across many provinces (e.g. Sichuan), spurring demand for modern bioenergy.

Since 2018, solar thermal energy consumption has grown 32% globally and is expected to expand another 25% (to over 2 EJ) by 2030. China remains the dominant solar thermal market in the buildings sector, but its global share is projected to decline from 85% to 63% due to rising competition from alternative technologies such as heat pumps and geothermal systems, and to a slowdown in construction activity. In this context, hybrid solutions that integrate solar thermal or hybrid PV thermal panels (which supply both electricity and heat) with heat pumps to enhance system efficiency merit further attention.

Increase in renewable heat consumption in buildings, and shares of renewables and of traditional biomass in heat demand in selected regions, 2018-2030



Source: IEA (forthcoming), World Energy Outlook 2025.

In terms of growth rate, the fastest-expanding solar thermal markets for the buildings sector are in sub-Saharan Africa, the Middle East and the European Union. In sub-Saharan Africa, solar thermal use is expected to triple by 2030, largely owing to its role in off-grid solutions for reliable water heating. Better access to financing and capacity-building programmes such as Soltrain in Southern Africa support this growth. In the Middle East, demand is set to triple by 2030, driven by national initiatives such as Jordan's May 2025 solar water heater programme, which targets low-income households and is funded through the Jordan Renewable Energy and Efficiency Fund.

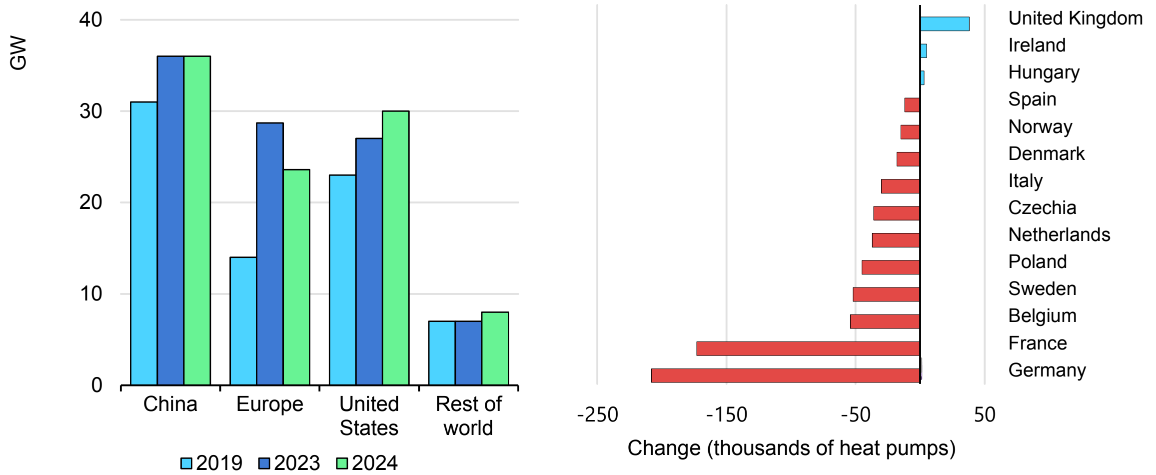
In the European Union, solar thermal use is expected to climb more than 50% by 2030, reaching nearly 170 PJ. A major policy driver is the 2024 recast of the Energy Performance of Buildings Directive, which introduced a solar mandate that requires the integration of solar technologies, including solar thermal systems, in new buildings, major renovations and all public buildings whenever technically and economically feasible. Member states are required to implement the mandate with phased deadlines from the end of 2026 through 2030, and to introduce support mechanisms to facilitate compliance.

Direct geothermal heat use in buildings has increased 34% since 2018 and is set to double by 2030, with China leading at nearly 40% of global geothermal heating in buildings by the end of the decade. The remaining majority of this growth comes from Iceland, Türkiye, the United States and the European Union. Strong policy frameworks (which include grants and drilling-risk insurance) and infrastructure support encourage this expansion, as do advances in drilling techniques that reduce capital predevelopment costs.

At a 50% increase, renewable electricity was the fastest-growing renewable heat source in buildings between 2018 and 2024, and it is expected to remain so throughout the outlook period, expanding by nearly two-thirds (+2.3 EJ). By 2030, renewable electricity will surpass modern bioenergy use in buildings, accounting for nearly one-third of total buildings sector renewable heat.

Overall, total heat electrification in buildings is projected to grow 64% by 2030, accounting for nearly 50% of all electricity use in the sector. Since 2018, renewable electrification of buildings has doubled in the European Union, China, Japan and the United States. Over the outlook period, several other countries are set to experience significant growth in electrification with renewables: India (+160%), China (+127%), New Zealand and Australia (+89%) and the United Kingdom (+81%).

Heat pump sales in selected regions, 2019, 2023 and 2024 (left), and change in annual heat pump sales in selected European countries, 2023-2024 (right)



Sources: IEA, Global Energy Review 2025; EHPA (2024), European Heat Pump Market and Statistics Report 2024; EHPA (2025), 2025 European Heat Pump Market Report.

The combined share of renewable electricity in buildings for China, the United States and the European Union is expected to rise from 60% to 75% by 2030. Heat pump deployment has played a major role in all these markets, and large additional contributions also came from other electric heating equipment.

Global heat pump sales declined slightly in 2024 (-1%). Europe registered the steepest drop (-21% or nearly 670 000 heat pumps), led by Germany (-48% or 208 000 pumps), France (-24% or 173 000 pumps) and Czechia (-63% or 36 000 pumps), as a result of a slowdown in new construction activity and policy uncertainty, particularly Germany's phase-out of targeted subsidies.

However, UK sales rose sharply (+63%) thanks to strong national incentives, but not enough to offset Europe's overall decline. Meanwhile, US sales rebounded strongly (+15%), allowing heat pumps to continue gaining ground over fossil fuel systems and outselling gas furnaces by 30%. In China, the world's largest market and manufacturer (particularly of key components such as compressors), growth stagnated in 2024, with sales increasing just 1%.

Not only do heat pumps use electricity, they also harness ambient heat from their surroundings (water, air and ground), enabling significant energy efficiency gains and lower overall energy use. Ambient heat in the buildings sector is therefore projected to expand more than 30% (+1.3 EJ) by 2030 – the second-largest increase after renewable electricity (+2.3 EJ). The largest expansion is in China (+0.4 EJ), followed by the European Union (+0.35 EJ) and the United States (+0.2 EJ), which together account for nearly 75% of the growth.

This expansion reflects recently strengthened policy support and financial subsidies. In Europe, many countries offer state-level subsidies for residential heat pumps, and in November 2024 the United Kingdom even announced a doubling of this funding. China is also very active: in May 2024, the State Council mandated a phase-out of coal-fired boilers with a steam capacity of less than 35 tonnes per hour by 2025. Since October 2024, the National Development and Reform Commission has been promoting the rollout of renewable energy heating technologies, including heat pumps, and in April 2025 the country launched an action plan to scale up heat pump manufacturing and deployment.

In the United States, ten states and Washington DC pledged to increase residential heat pump sales to 65% by 2030 and 90% by 2040. As part of this effort, a draft action plan released in April 2025 outlines how they will co-ordinate programmes, data collection and market tracking.

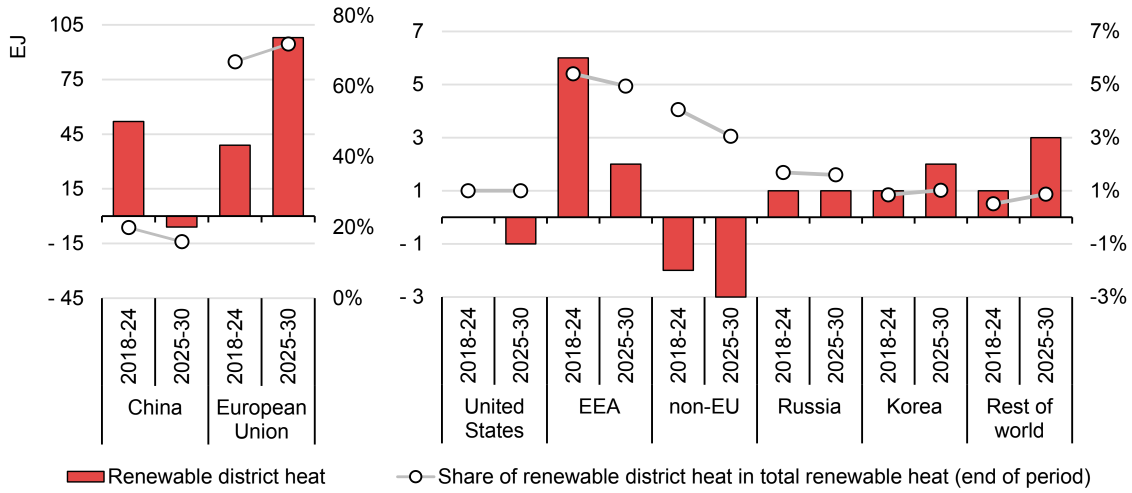
District heating

Between 2018 and 2024, renewable district heating capacity expanded 20% (+100 PJ) and is set to reach 688 PJ by 2030, up from 592 PJ today. It currently accounts for 4% of global renewable heating demand in buildings, and its share is expected to fall to 3% as electrification, ambient heat and modern bioenergy use accelerate. Although renewables hold significant untapped decarbonisation and efficiency potential, district heating systems remain heavily reliant on fossil fuels.

In China and in some countries in Eastern Europe, district heating networks often operate at high temperatures, leading to significant energy losses and complicating the deployment of renewables. Conversely, other countries such as

[Denmark and Austria](#) are transitioning to low-temperature district heating systems to enhance energy efficiency and facilitate greater use of renewable energy sources.

Renewable district heating in buildings and share of renewable district heating in total renewables in buildings in selected regions, 2018-2030



Notes: EEA = European Economic Area (Iceland, Norway, Türkiye, Switzerland and Israel). Non-EU covers Albania, Belarus, Bosnia and Herzegovina, Gibraltar, the Republic of Kosovo, North Macedonia, the Republic of Moldova, Montenegro, Serbia and Ukraine.
Source: IEA (forthcoming), World Energy Outlook 2025.

China remains the world's largest district heating market, relying primarily on coal-fired CHP plants to meet its growing heat demand. Although the use of renewables in its district heating systems has increased nearly 80% since 2018, reaching close to 120 PJ, this growth is set to decelerate by 2030. While China's 14th Five-Year Plan supports geothermal expansion, large-scale solar thermal developments, biomass retrofits and large-scale heat pump deployment to make the heating network cleaner, coal-based infrastructure and system constraints continue to impede faster renewable energy uptake.

Since 2018, the use of modern renewables in district heating in the European Union, which has the highest share of renewables in district heating in the world, has grown 11% to reach almost 400 PJ and is expected to approach 500 PJ by 2030, thanks to increased policy attention and financial support.

Owing to projects in Germany, Finland, Denmark, Austria, France and Estonia, the installed capacity of large heat pumps in European district heating networks is set to rise significantly by 2030. Studies indicate that large heat pumps could supply 10% of district heating by 2030 and 20-30% by 2050. In Germany alone, capacity could reach 6 GW by 2030 and 23 GW by 2045 – representing one-third of total district heating output – with government policy support.

Under new EU rules, district heating and cooling systems must source at least 50% of their energy from renewables, waste heat or high-efficiency cogeneration by 2027 to qualify as efficient, a designation that enables faster permitting and unlocks access to additional funding, including from the LIFE programme and national resiliency and recovery plans, such as the one in Germany. For the first time, waste and surplus heat are recognised as renewables, and member states are required to assess their technical potential in district heating and cooling systems every five years. Starting in 2026, the share of renewables in district heating and cooling should grow 2.2 percentage points each year, with new or upgraded installations required to meet these targets.

Cities with populations of over 45 000 are now mandated to prepare local heating and cooling plans, and national governments of member states must provide financial and technical support, including for dedicated municipal staff, as many local administrations rely heavily on external contractors. For example, the Netherlands requires that local heating plans align with regional energy strategies and, like Sweden, it funds dedicated staff for heat planning. Meanwhile, Wallonia, France, Estonia and Ireland offer direct financial support for feasibility studies. In 2024, the European Investment Bank's JASPERS (Joint Assistance to Support Projects in European Regions) programme significantly expanded its advisory support for district heating and cooling decarbonisation and extended its assistance to Ukraine and Moldova.

Continued growth is also projected in Iceland, Korea and Russia to 2030. In February 2025, the Korean government announced a substantial expansion of its district heating network by 2028, with clean energy sources.

Technology trends to watch for by 2030

Geothermal energy for district heating

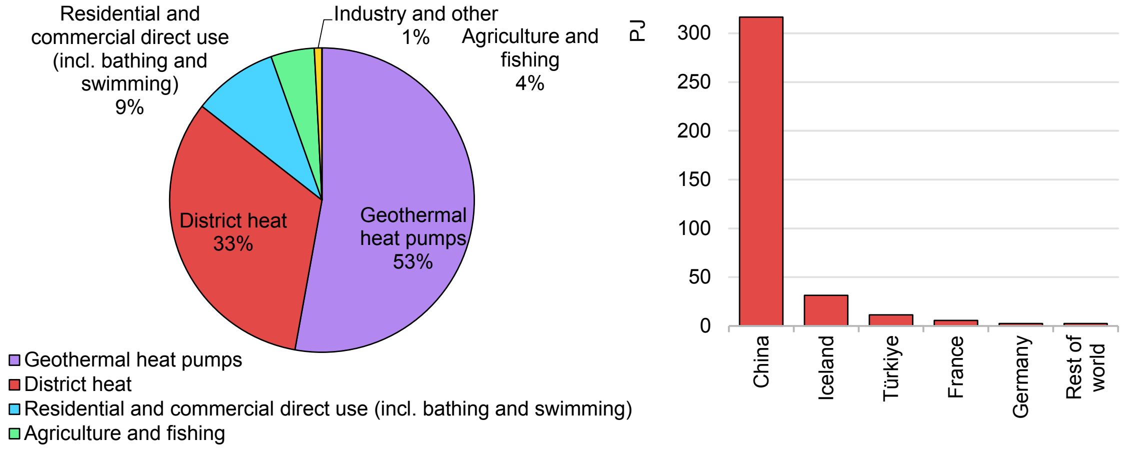
Geothermal heat provides about one-third of all district heating system heat globally. Its use has gained momentum thanks to stronger policy frameworks (that include grants and drilling-risk insurance), infrastructure support and advances in drilling techniques that have reduced capital predevelopment costs.

China is the world's largest user by volume, accounting for two-thirds of global geothermal district heat consumption in 2023. Although geothermal energy supplies just 4% of the country's overall district heating, which remains coal-heavy, its use has grown 2.5-fold since 2019 and now spans more than 120 million m^2, serving more than 70 cities across 11 provinces, including Beijing, Tianjin, Shaanxi, Hebei, Henan, Shandong, Shanxi and Hubei.

Iceland is the world's second-largest user, accounting for 9% of global geothermal district heat consumption in 2023. Other key markets are Türkiye, France, Germany, Hungary, Italy and several other European countries.

In the United States, around 23 geothermal district heating systems are in operation, serving campuses, communities and individual facilities. However, unlike in Europe and China, large-scale policy and financial incentives for geothermal district heating remain limited.

Geothermal heat demand by application, world (left), and geothermal district heating in selected countries (right), 2023



Source: Based on IEA (2024), The Future of Geothermal Energy.

Since 2024, policy support for geothermal district heating has been stronger and there have been new project developments. In November 2024, the European Council called for faster geothermal deployment, streamlined permitting and easier access to financing. It also proposed the creation of a European Geothermal Alliance.

In Germany, Vulcan Energy resumed operations of a 2-MW_{th} geothermal heating plant in early 2024 and began drilling a new geothermal well in 2025, with plans to integrate it with lithium extraction. Meanwhile, Eavor's first commercial deep-geothermal project (64 MW_{th}) is aiming for production in late 2025. In Estonia, three pilot plants are under way following a national resource planning project. New projects are also emerging in Hanover, Neuss and Parchim (Germany), Copenhagen (Denmark), Poznan (Poland) and in several Dutch municipalities that are exploring a joint heating network.

In Hungary, public funds support geothermal district heating development. France has 75 geothermal district heating systems in operation, and six cities near Paris are expanding their networks, with new wells planned by 2026, supported by the modernised Fonds Chaleur. In Switzerland, exploration activity for heat resources is high, notably in cantons with a mature regulatory regime for subsurface resource exploitation. In the United States, a city in Idaho is assessing geothermal district heating and cooling possibilities to reduce local energy costs. Meanwhile, Iceland launched a 2025 initiative to extend geothermal heating to the remaining 10% of households not yet connected.

The economics of geothermal district heating are also increasingly favourable: heat costs typically range from USD 5-30/GJ, depending on geological and regulatory conditions. In the European Union, the average geothermal heat cost was around USD 22/GJ in 2014, compared with USD 10/GJ in the United States in 2017. Most geothermal potential in Europe lies at depths of more than 3 km, where sedimentary aquifers can be tapped directly. Enhanced and closed-loop systems could unlock even deeper resources, especially when combined with heat pumps or cogeneration to improve economic viability.

Solar thermal energy for district heating

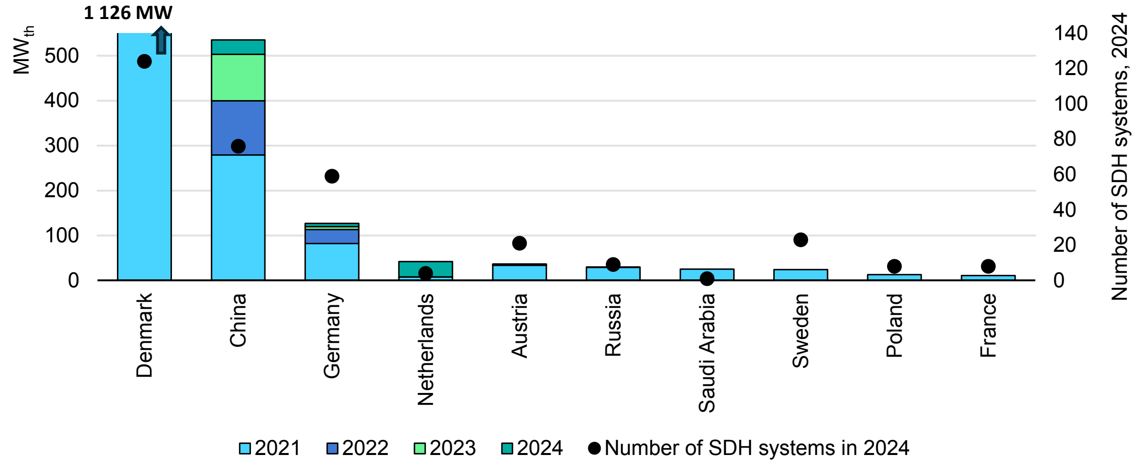
Growth in both the number and scale of solar district heating (SDH) systems has been notable. As of 2024, 346 large-scale SDH systems (>350 kW_{th}/500 m^2) were operational globally, with nearly 2 GW_{th} of installed capacity – a 20% increase from 2021, though growth slowed to just 4% in 2023-2024. Denmark and China remain global leaders, together hosting 18 of the world's 20 largest SDH plants.

In 2024, 10 new SDH systems with a total capacity of 74 MW_{th} came online. China has four of them, with a capacity of 32 MW_{th}. The other six additions are in the European Union: three in Germany (7 MW_{th}), one large system (the world's fourth-largest, which uses underground thermal energy storage for seasonal storage) in the Netherlands (34 MW_{th}), one in Italy (0.6 MW_{th}) and one in Austria (0.4 MW_{th}). A further 16 systems (143 MW_{th}) are being planned or are under construction across the European Union.

Beyond traditional markets, SDH is also gaining traction in emerging regions. In the Western Balkans, two large-scale SDH projects are under development: a 44-MW collector field with seasonal storage in Kosovo, and a 27-MW collector field in Serbia, paired with a heat pump (17 MW), an electric boiler (60 MW) and seasonal storage.

Outside of Europe and China, SDH systems are in operation in Saudi Arabia, Japan, Kyrgyzstan, Russia, the United States, Canada and South Africa.

Solar thermal district heating in selected countries, 2021-2024



Notes: SDH = solar district heating.
Source: IEA Technology Collaboration Programme (2023), Solar Industrial Heat Outlook 2023-2026.

Solar thermal systems have three times greater land-use efficiency than solar PV for heat generation, making them very suitable for cities looking to retrofit or expand their district heating networks. In rural areas, land availability also makes solar district heating an attractive option. Less than 1% of European district heating systems currently integrate solar thermal, which is an addition to other renewable district heating sources.

Costs are falling quickly: every doubling of installed capacity results in a 17% cost reduction for solar district heating. In Denmark, the levelised cost of heat is already around EUR 40/MWh, and in sunnier countries such as Spain, it could drop to EUR 20/MWh when combined with seasonal thermal storage. EU policy mandates, renewable energy targets and dedicated financial support are expected to remain key drivers for growth in solar thermal deployment for district heating.

Industry

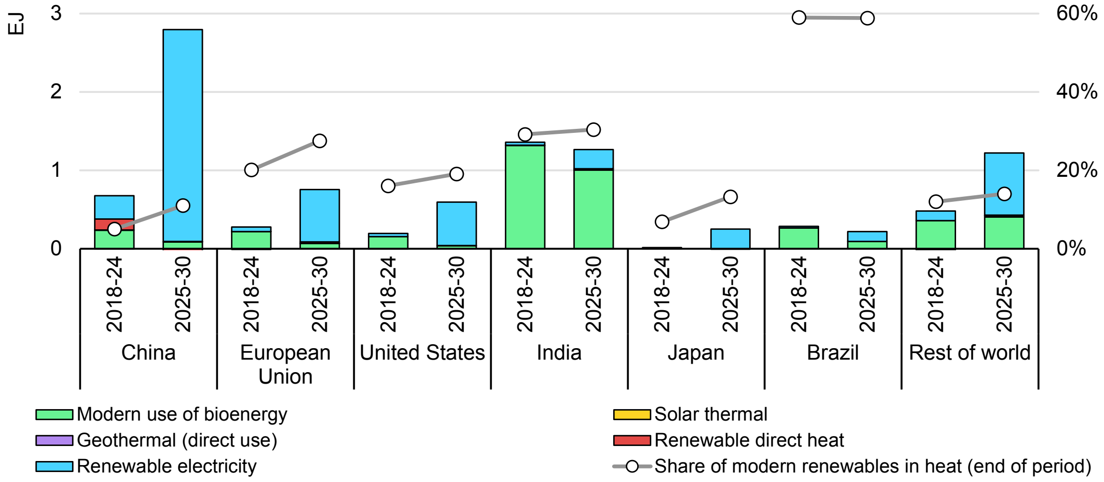
As a critical form of energy for industrial processes, heat accounts for 26% of global energy consumption. It represents about two-thirds of total industry energy use and is set to rise a further 14% by 2030. However, as most industrial heat is still produced using fossil fuels, it accounted for around 60% of energy-related CO_2 emissions from heat in 2024.

While the share of renewables in industrial heat demand has remained roughly stable at 12% since 2018, new policies and industry initiatives are expected to raise this portion to 16% by 2030. However, fossil fuel use is also expected to grow and will continue to meet the significant majority of industry sector demand.

Regional trends in renewable heat consumption vary widely, depending on how a country's industry sector is structured. China, the European Union and Japan are expected to experience strong growth in renewable heat use between 2024 and 2030. In China, however, renewables meet only 8% of total industrial heat demand by 2030 – the lowest share of major industrial economies – primarily because China's heavy industry, which requires high-temperature heat, is more difficult to decarbonise.

In contrast, India and Brazil currently have the highest shares of renewable energy in their industrial heat consumption because bioenergy is readily available and heat electrification is increasing, especially in the agrifood and sugar sectors, which use bioenergy residues. Still, both are expected to have little or no increase in their renewable heat share, as growing fossil fuel use offsets gains from renewables. In India, coal mines are being reopened to meet rising industrial energy demand, especially in the cement and steel sectors. Fossil fuel use is also increasing in Brazil, as the country is finding it difficult to expand renewable energy supplies quickly enough to keep pace with demand in energy-intensive industries.

Renewable heat consumption in industry and share of renewables in heat demand in selected regions, 2018-2030



Source: IEA (forthcoming), World Energy Outlook 2025.

While modern bioenergy remains the largest contributor to renewable industrial heat production globally (12 EJ), its share is expected to drop more than 14% by 2030 as electrification gains ground. The exceptions are India and Brazil, where modern bioenergy continues to fuel more than 90% of renewable industrial heat generation, particularly in the food, pulp, cement, ironmaking and construction industries. In most other regions, declines result from concerns over feedstock availability and sustainability, and growing competition in demand from transport and buildings.

The largest increase in renewable heat use comes from renewable electricity-based heat, which is expected to more than quadruple by 2030 – rising from 11% today to meet nearly one-third of total renewable heat demand. Policy and regulatory support, and corporate decarbonisation commitments, spur this increase. Although industrial solar thermal consumption declined 46% between 2018 and 2024, the market is expected to rebound and expand fivefold by 2030. This recovery will result from stronger regulatory support and financial incentives in some countries and regions (including the European Union, China and India), as well as technology improvements and the integration of solar thermal energy generators with storage systems, enabling continuous heat supply.

Although geothermal-based heat generation is expanding rapidly, it still accounts for less than 1% of renewable industrial heat. Since 2018, geothermal energy use in industry has grown more than 20%, and it is projected to increase nearly 60% by 2030 thanks to strong policy measures (e.g. grants and drilling-risk insurance), infrastructure support and emerging strategies such as clean-heat targets and carbon pricing.

With levelised costs ranging from USD 4/GJ to over USD 40/GJ, geothermal heat is already competitive with natural gas in regions with good resource potential and high natural gas prices. Deployment is concentrated in the food processing and horticulture sectors in France, India, Kenya, New Zealand, the Netherlands and Türkiye, while Germany and the Netherlands are exploring geothermal applications in industrial clusters, and New Zealand is using geothermal energy for pulp and paper mills and wood processing.

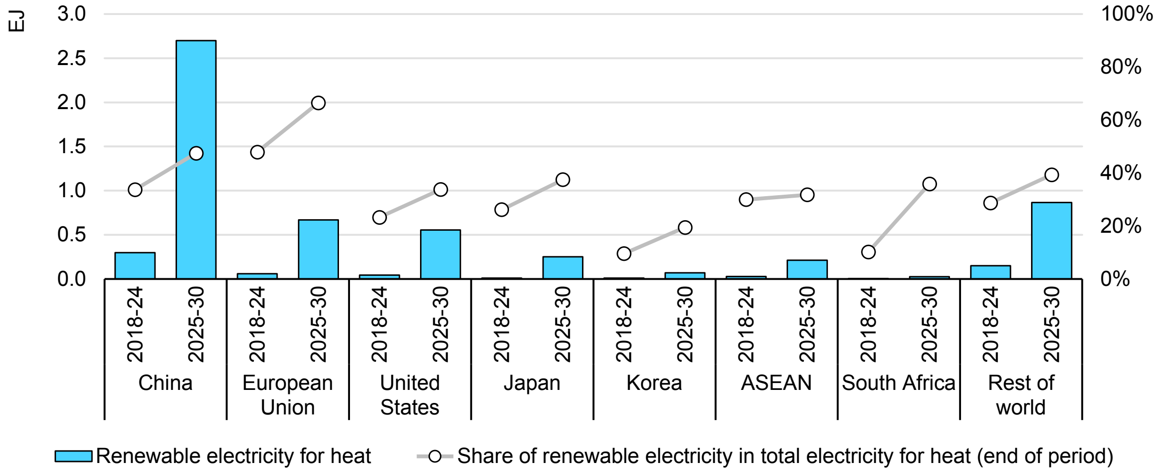
Technology trends to watch for by 2030

Electrification of industrial heat processes

The electrification of industrial heat with renewable electricity is accelerating and is expected to more than quadruple by 2030 to nearly 7 EJ. The share of electrified heat is thus projected to rise from 11% today to over 40% of total renewable heat demand by 2030.

This shift is unfolding globally, led by Japan (+645%), China (+485%), the United States (+460%), Korea (+413%), the European Union (+344%) and South Africa (+340%) ASEAN (+286%). By 2030, these seven markets are expected to account for 80% of renewable electricity used in industrial processes, compared with around 60% of total industrial heat consumption. Growth in renewable electricity is outpacing overall heat use, driven by a mix of targeted industrial strategies, regulatory reforms and industrial initiatives.

Renewable electricity in industrial heat and share of renewable electricity in total electricity for industrial heat in selected regions, 2018-2030



Note: ASEAN = Association of Southeast Asian Nations.
Sources: IEA (forthcoming), World Energy Outlook 2025; IEA (forthcoming), Electrification of Industrial Heat: Opportunities for Renewables.

For example, in 2024 the European Union set ambitious industrial electrification targets of 48% by 2040 and 62% by 2050, which the industry sector backed strongly. Relaxed state aid rules and a EUR 1-billion heat auction programme (set to launch in late 2025) support the implementation of these targets. While the auction rules are currently being finalised, capacity is to be separated according to temperature requirements – into processes needing heat below 400°C and those needing it above 400°C. In addition to promoting electrification (and geothermal and solar thermal energy use), the auctions plan to target the reuse of industrial waste and to require storage solutions for projects with a coefficient of performance below two to minimise peak-hour electricity consumption.

Meanwhile, China's May 2024 decarbonisation action plan and April 2025 heat pump action plan, and Japan's December 2024 Green Transformation (GX) 2040 Vision, target direct and indirect electrification of industrial processes through industrial clustering and financing mechanisms.

In the United States, industrial electrification has been gaining momentum, driven by industry leadership and state-level policy support. For example, NYSERDA (the New York State Energy Research and Development Authority) launched its seventh round of the Commercial and Industrial Carbon Challenge in May 2025, offering up to USD 5 million for each project that shifts or expands electrification of industrial heat, while California's INDIGO scheme and FPIP continue to fund industrial decarbonisation and electrification, with new calls in 2024 and 2025. Other states, including Oregon, Washington and Pennsylvania, are also expanding their financial support, though not yet at the scale of New York and

California. However, many federal demonstration and loan programmes were cancelled in early 2025 following release of the Unleashing American Energy executive order and the One Big Beautiful Bill.

The greatest electrification uptake is expected in industries that require low-temperature heat and steam (below 300°C), such as food and beverages, paper, textiles and chemicals. In these subsectors, mature technologies such as electric boilers and industrial heat pumps can be readily deployed without major process disruptions and paired with thermal energy storage systems to buffer fluctuations in electricity supply from directly connected variable renewables.

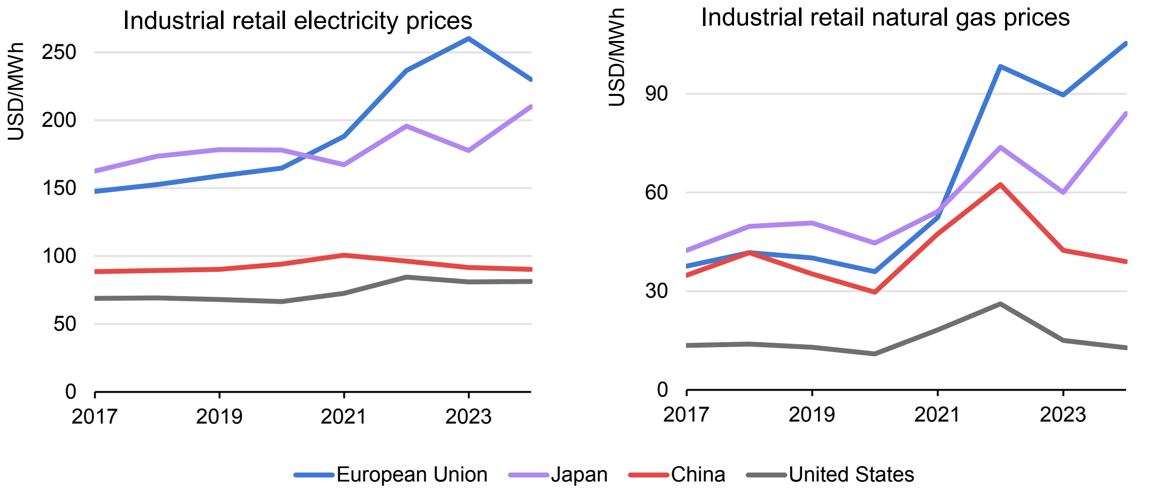
Conversely, electrifying high-temperature industrial processes (above 300°C, and often exceeding 1 000°C) in sectors such as iron and steelmaking will remain challenging. While technically feasible, it will require major process redesigns, high upfront costs, the adoption of emerging technologies such as plasma heating, and stronger policy support to drive demand for these low-emissions products.

Despite technological readiness, practical hurdles impair the attainment of full electrification, especially grid connection issues and high electricity prices in many regions, which often make electrification less competitive with natural gas. At the same time, partial electrification of specific industrial sites is already under way and represents a critical and significant step in industrial decarbonisation.

In terms of electricity price, the average EU industrial retail electricity price decreased slightly from USD 260/MWh to USD 230/MWh in 2024 but remained among the highest globally, around 1.5 times higher than China's and almost double the US average. Japan's prices also climbed, nearly reaching EU levels. High taxes and levies, which make up an average 22% of EU industrial power bills, contribute significantly to this gap.

Plus, natural gas prices in the European Union and Japan remained elevated while those of the United States and China returned to pre-energy-crisis levels. In 2024, industrial retail gas prices differed considerably among these four markets, with the United States often paying substantially less (in some cases around eight times less on average) than the other three markets. This is largely due to the stability of US domestic supplies, lower energy prices and taxes, and infrastructure advantages. However, these generalisations are based on average national prices, and individual state prices can vary considerably.

Industrial natural gas and electricity retail prices in major economies



Note: These are average industrial retail electricity and gas prices and incorporate taxes, including recoverable taxes.
Source: IEA (2025), Energy Prices; Global Petrol Prices (2025), GlobalPetrolPrices.com (accessed 20 August 2025).

A key challenge for industrial electrification is not the absolute electricity price, but its price relative to natural gas. In 2024, the electricity-to-gas ratio averaged 6:1 in the United States (the highest among these four markets), compared to about 2:1 elsewhere. Prices vary within each country or province, as different states or provinces often impose their own taxes, levies and grid costs. Generally, a ratio of 3:1 already makes a compelling economic case for electrification, as modern industrial heat pumps can deliver up to three times more heat per unit of electricity than conventional gas systems. Beyond economics, however, other challenges such as grid connection, standardisation and high initial investments also need to be addressed.

Progress hinges on keeping electricity prices competitive by adjusting taxes, levies and network costs for industrial consumers. This also includes accelerating investments in domestic renewables and grid infrastructure. Lengthy grid connection times for industrial consumers sometimes reach up to seven years and continue to deter investment in electrification. Policy makers, regulators and system operators have begun to address these issues. Recent steps include the European Agency for the Cooperation of Energy Regulators (ACER) December 2024 recommendations to amend the HVDC Network Codes for easier industrial grid connection; the Netherlands' various actions to unlock unused grid capacity; and new measures by California's CAISO (May 2025) and New York's NYISO (June 2025) to support demand flexibility and grid reliability as industrial electricity use rises.

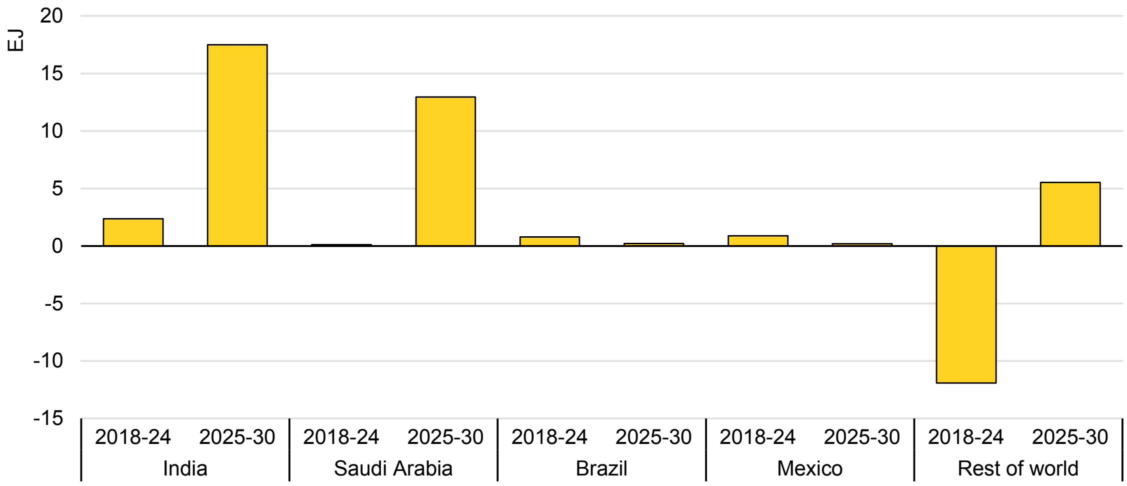
Economic viability is critical, but for major gas-importing regions such as the European Union, China and Japan, the rationale for electrification extends beyond cost to include energy security. Reliance on global LNG markets exposes these economies to price volatility and supply risks, so accelerating electrification and renewable energy deployment can help insulate industries in these countries from geopolitical shocks and market disruptions.

Solar thermal energy for industry

Industrial solar thermal consumption fell significantly (by around 46%) during 2018-2024, largely due to a sharp drop between 2021 and 2022 in the key markets of Türkiye and Israel.[9] Since 2022, the market has partially recovered and grown, but at a slower pace. Despite this overall drop, several countries, including Brazil, Mexico, Saudi Arabia and India, registered growth in their food and beverage, machinery, textile, alumina and mining industries. The market is expected to rebound and expand fivefold by 2030, thanks to supportive regulations in some regions, strong industrial decarbonisation commitments (for example in sectors such as alumina), and the technology's ability to deliver high-temperature solar heat solutions.

One of the major policy pushes in the European Union will be a EUR 100-billion industrial decarbonisation bank, with the first EUR 1-billion heat auction to be launched in late 2025. The exact rules for the auctions are currently being finalised, but the aim is to include several technologies (electrification of heat; solar thermal and geothermal; waste heat; and thermal storage), and auctioned capacity will be split into processes below and above 400°C.

Industrial solar thermal consumption in leading countries, 2018-2030



Note: Industrial electricity demand includes demand for electrified heat.
Source: IEA (forthcoming), World Energy Outlook 2025.

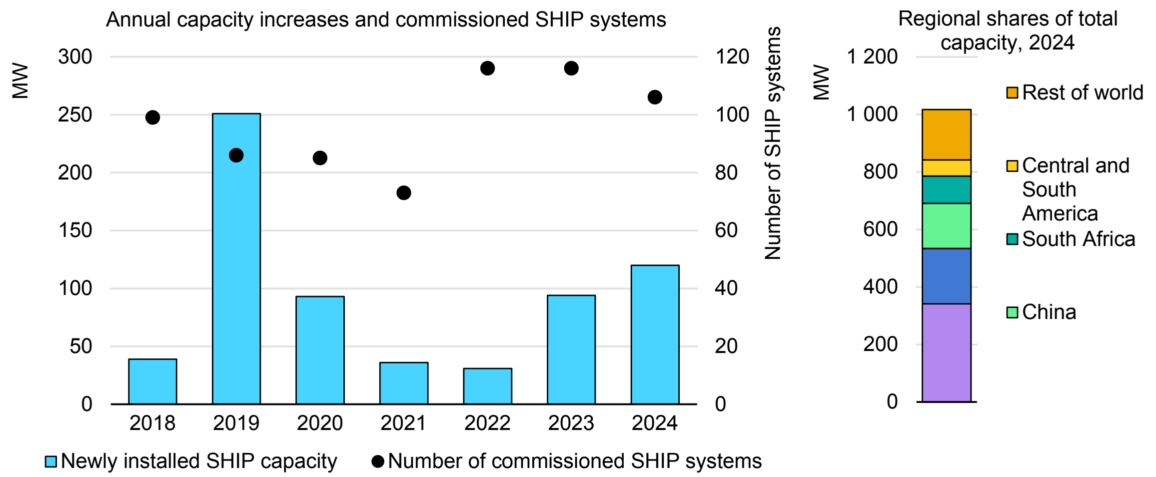
[9] The statistical data for Israel are supplied by and under the responsibility of the relevant Israeli authorities. The use of such data by the OECD is without prejudice to the status of the Golan Heights, East Jerusalem and Israeli settlements in the West Bank under the terms of international law.

The global solar heat for industrial processes (SHIP) market rebounded strongly in 2024, reaching a five-year high with a 30% increase in new installed capacity. A total of 106 new systems added 120 MW_{th}, led by China with an 80-MW_{th} parabolic trough project for a leisure park. Other highlights are Latin America's first linear Fresnel plant in Mexico (111 kW_{th} of capacity), producing 180°C steam; Germany's demonstration plant, which began producing renewable fuels in September 2024 and has since secured several offtake agreements with airports and the shipping industry; Kenya's 180-kW solar thermal system with 1 MWh of storage for a tea plantation; and a 4.1-MW_{th} brewery in Spain that uses linear Fresnel collectors.

In Croatia, construction began in 2024 on a winning Innovation Fund solar thermal project (combined with thermal storage, a waste heat recovery system and two heat pumps). However, despite the overall rise in SHIP capacity, the total number of new projects dropped slightly, mainly due to a 30% subsidy cut in the Netherlands that led to several project cancellations.

At the end of 2024, the global SHIP market totalled 1 315 systems with a combined capacity of 1 071 MW_{th} and 1.5 million m^2 of collector area. The technology mix has also changed, with concentrating collectors making up 69% of new capacity, heavily influenced by the aforementioned large-scale project in China. The market is also trending towards larger systems, with average system size growing more than 40% in the past year alone.

Annual industrial solar thermal capacity increases and number of commissioned SHIP projects, 2018-2024 (left), and regional shares of total industrial solar thermal capacity, 2024 (right)



Note: SHIP = solar heat for industrial processes.
Source: IEA Technology Collaboration Programme (2023), Solar Industrial Heat Outlook 2023-2026.

Although a high levelised cost of heat (LCOH) from industrial solar thermal systems once contributed to slow deployment, this cost has dropped 40-70% in the past decade thanks to technological improvements and economy-of-scale savings.

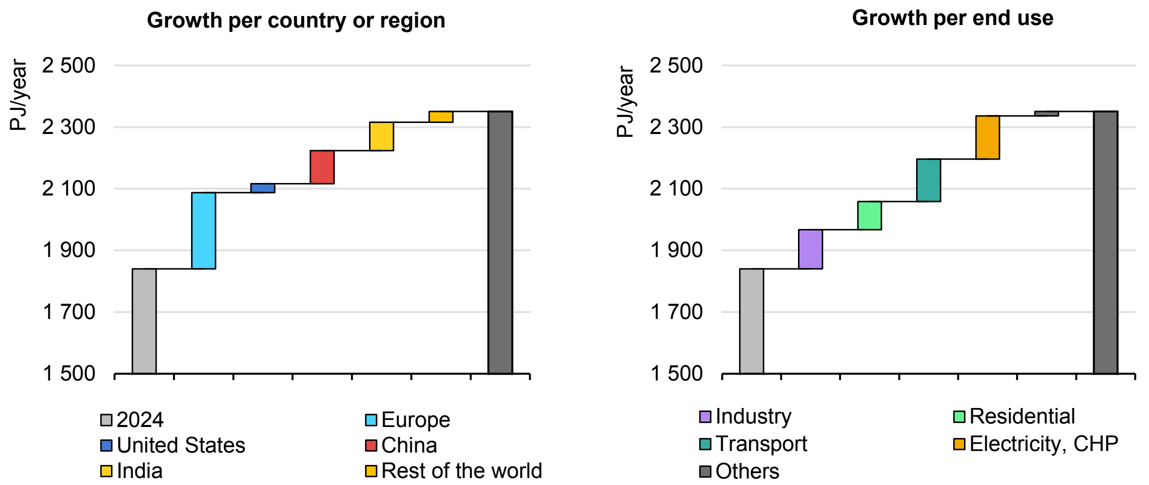
Chapter 4. Biogases

Global summary

Policy attention to biogas and biomethane has increased significantly in the past five years as more countries recognise their potential role in the transition to sustainable energy systems. Several key factors are driving this surge. First is the growing importance of energy security following the energy crisis triggered by Russia's invasion of Ukraine and recent geopolitical developments. Second is the need to accelerate decarbonisation in hard-to-abate sectors, together with growing emphasis on methane emissions reductions.

Third, countries are paying more attention to the circular economy concept, recognising that biogas production can help revalorise organic waste and residues. Finally, as rural areas are losing population in many regions, biogas and biomethane development can contribute to rural economic growth.

Global biogas growth by country and end use, 2024-2030



Notes: CHP = combined heat and power. Europe includes Austria, Belarus, Belgium, Bulgaria, Croatia, Cyprus, Czechia, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Latvia, Lithuania, Luxembourg, Malta, Moldova, the Netherlands, Norway, Poland, Portugal, Romania, Slovakia, Slovenia, Spain, Sweden, Switzerland, Türkiye, Ukraine and the United Kingdom.

The 2021-2023 period was marked by growing international recognition of biogases, reflected in the adoption of national strategies and the setting of ambitious 2030 targets in several countries and regions, including the European Union, India and China. In mature markets such as Germany, France and

Denmark, governments have built on more than a decade of experience to set even more ambitious goals for biogas and biomethane deployment.

At the same time, in large emerging economies such as China and India, with a strong presence of traditional small-scale household biogas systems, governments are driving a shift towards industrial-scale production, setting new strategic goals. Additionally, a third group of countries that has strong potential to produce biogases but limited previous development experience (Brazil, and European nations such as Spain, Poland, Ireland and Ukraine) have begun implementing national policies to support and scale up production of biogases.

Following target setting and the introduction of main regulations, markets began to respond in 2023 and 2024. In 2023, production accelerated in many regions – for instance in the United States, spurred by the 2022 Inflation Reduction Act (IRA), which introduced generous tax credits, and in Europe by revised tariffs that accounted for rising inflation.

However, signs of stagnation began to appear in 2024 in some of the most mature markets in Europe. Worsening market conditions – due to rising feedstock costs and less attractive remuneration – have dampened momentum in Germany, Denmark and the Netherlands. In Germany, the world’s leading biogas market, investment has slowed due to ongoing uncertainty surrounding future public support for the existing biogas-to-power fleet and lower carbon credit prices in the transport sector since 2023. However, growth in France and Italy remains strong. In the United States, the ending of some investment tax credits at the end of 2024 drove accelerated investment activity.

Growth continued in China and India, with annual increases of 3-4%. Meanwhile, production in new markets has struggled to take off, suggesting that biogas scale-up in these regions may take longer than initially anticipated.

Some governments are beginning to respond to market signals by introducing tax modifications and inflation considerations and providing new guidance to reduce uncertainty in key sectors (as detailed in the regional analysis). Production will need to accelerate significantly in existing markets and a clear take-off will have to be achieved in emerging ones to stay on track with established goals. The next two years will be critical in determining whether the momentum can be regained.

Global combined biogas and biomethane production is expected to expand 22% from 2025 to 2030. This represents a 4% increase in 2030 from last year’s forecast. Net growth will come from biomethane owing to its versatility and the opportunity to use natural gas grids and equipment, which could make it possible to displace fossil fuels for hard-to-electrify uses with minimum infrastructure investment. However, direct biogas use, mainly for electricity or combined heat and power (CHP) generation, remains a relevant growth driver in regions with limited gas pipeline infrastructure (e.g. Brazil, India and China).

Regional trends and forecasts

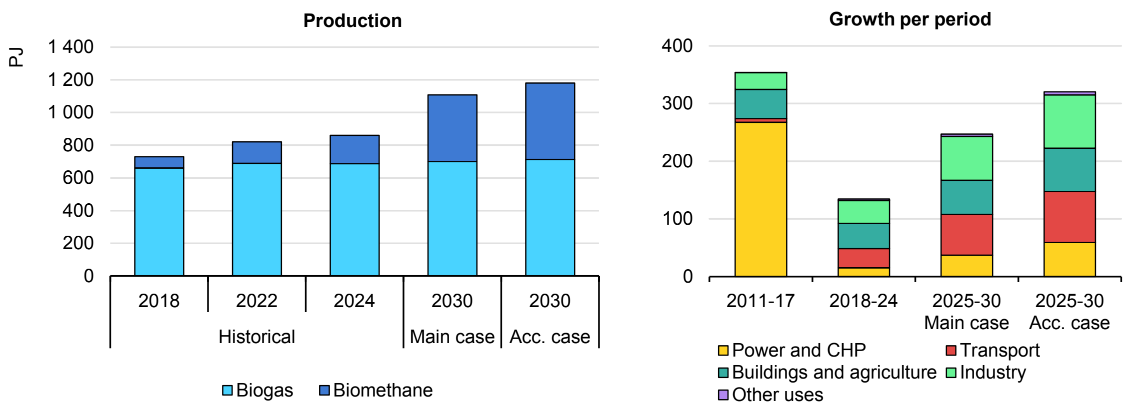
Europe

In 2024, EU production of biogases increased 3%. Growth was modest in biogas (1% year on year), but significantly higher for biomethane (14% year on year).

The production of biogas, used primarily for electricity and CHP generation, is highly concentrated in Germany (53% of EU production). Following a period of decline, interest in biogas is reviving (see country analysis below). Countries with smaller markets (Greece, the Slovak Republic, Spain and Poland) are expanding their biogas output. In contrast, biogas use is declining in other countries, with production shifting towards biomethane. Policy tools that allocate tenders for both new biomethane plants and upgrades of existing biogas facilities (e.g. in Italy and the Netherlands) support this shift.

Biomethane production is on the rise in most European countries, with Germany (29% of EU production), France, Italy, Denmark and the Netherlands collectively accounting for 93% of EU production. The United Kingdom also contributes significantly, with production equivalent to an additional 23% of the EU total.

Production of biogases in Europe, 2010-2030



Note: CHP = combined heat and power.

Several countries are working on their regulations to attract further investment. In Denmark, growth stagnated during 2024 due to higher feedstock costs and unfavourable market conditions. To avoid major exports of domestic production, the government is revising its CO_2 taxes that currently apply to biomethane.

Meanwhile, the Netherlands is developing a new blending mandate for grid injection, set to take effect in 2026. This measure is expected to boost growth significantly.

Emerging producers such as Ireland, Spain and Poland are scaling up production, but more slowly than what is required to meet their national targets. Ireland has a national blending mandate for heating, a strong policy stimulating expansion. Spain and Poland, however, are facing social acceptance challenges that are delaying deployment.

Overall, achieving the EU 35-bcm target by 2030 will require a marked acceleration in growth across both mature and emerging markets. To stay on track, year-on-year growth between 2024 and 2030 should average around 16% for biogas and biomethane combined and would need to increase 1.6-fold annually if focusing solely on biomethane. Our forecasts estimate that by 2030, the European Union will achieve 68% of its target with combined production, but only 27% if the target is applied exclusively to biomethane.

Use in the transport sector continues to grow, especially where renewable energy targets based on GHG emission reductions make biomethane very competitive. Markets for bio-LNG are emerging in Germany, Italy and the Netherlands, owing to its suitability for long-haul trucking. Additionally, a first contract for maritime use was signed in the Netherlands, although regulations are still being adapted.

Main policies and regulations in the EU biogas/biomethane sector

Policy	Year	Key information
Waste Framework Directive (WFD) (EC/2009/98)	2009 amendment	Set an obligation to collect organic waste separately starting in 2024.
Renewable Energy Directive II	2018	Obligated fuel suppliers to include a minimum share of renewable energy in transport. Made biomethane eligible for compliance. Allowed advanced fuels to count double. Imposed thresholds for minimum GHG reductions.
Renewable Energy Directive revision (RED III) (EU/2023/2413)	2023	Broadened the biomethane scope to cover all final uses. Improved permitting.
REPowerEU plan (COM/2022/230)	2022	Aimed to reduce fossil fuel import dependence. Targeted 35 bcm of biogas and biomethane by 2030.
EU Emissions Trading System (ETS)	2005	Established a cap-and-trade carbon market covering emissions from electricity and heat generation, some industrial sectors and aviation, and (from 2024) maritime transport.
EU Emissions Trading System (ETS2)	2023 revision	Added coverage for GHG emissions from fuel combustion in buildings, road transport and additional industrial sectors. Will be fully operational in 2027.

Creating a unified European market for trading green certificates remains a key challenge. Proof of sustainability (PoS) is the key certificate recognised by the European Commission to comply with mandates and targets, and it is also used in many member states. It certifies compliance with sustainability requirements under the EU Renewable Energy Directive (RED).

Additionally, Guarantees of Origin (GOs) are used to certify renewable origins for consumers, and they are normally used in voluntary markets. Rules vary drastically. In some countries, only unsubsidised biomethane can sell GOs, while in others it is allowed and taken into account in the subsidy (e.g. Denmark). Some countries restrict GO exports, while others, following European Commission intervention, now accept foreign GOs to meet blending targets. These differences create market fragmentation and hinder the development of a common EU system. The new Union Database, expected to be operational for biogases in 2025, will facilitate the tracking of PoS certificates required under the RED.

Germany

Germany remains the world's largest biogas and biomethane market, with a combined production of 329 PJ in 2024. However, its output has remained quite stable since 2017, unlike fast-growing markets such as France, Italy and Denmark.

Driven by feed-in tariffs introduced in 2000, 72% of the biogases produced are used for power generation. However, Germany shifted to a tender allocation system in 2017 and modified reward conditions, resulting in plateaued production. To attract investment, policies are being revised to improve reward conditions under the biomass-for-power tenders. Many plants are approaching the end of their 20-year FIT contracts and are seeking new support programmes. In 2025, the government introduced a Biomass Package to support both new and existing biogas plants, to prevent decommissioning and increase grid flexibility with dispatchable renewable energy.

Power generation (under the EEG, Germany's Renewable Energy Sources Act) used up 45% of biomethane production in 2024, but this share has been declining since 2017, reflecting a shift towards more lucrative markets such as heating and transport.

Transport usage has driven biomethane demand growth in the last five years, supported by Germany's GHG quota system, which rewards low-emission fuels. This system particularly favours biomethane, especially when it is made from animal manure, as this this type of feedstock can lead to very low (sometimes negative) GHG emissions. However, Germany's draft RED III transposition, to be adopted in 2026, is likely to eliminate the double-counting benefit for biofuels made from waste, in force in the European Union since 2009. From 2018 to 2023, transport biomethane use rose 4.6-fold, though growth slowed in 2022 and 2023 due to a sharp drop in quota prices, following a biodiesel credit oversupply tied to suspected fraud. This has created ongoing uncertainty over quota prices.

Lastly, the Buildings Energy Act (GEG) promises the possibility of a major future market for biomethane over the medium term. It requires 65% renewable energy in heating systems in new buildings in developing areas by 2024 and 100% by 2045, and lower rates for existing buildings, starting at 15% in 2029 and ramping up to 60% by 2040. According to the German Energy Agency (dena), biomethane use in buildings could grow to 13-45 TWh/year by 2040, significantly expanding its role in Germany's energy transition.

Main policies and regulations in Germany's biogas/biomethane sector

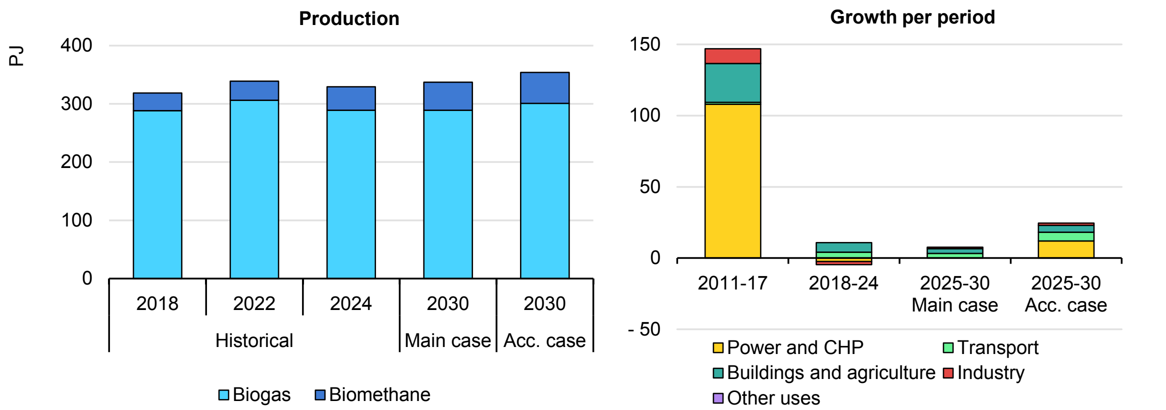
Policy	Year	Key information
Renewable Energy Sources Act (EEG)	2000	Offered feed-in tariffs for renewable electricity production.
	2017 amendment	Shifted to an auction system for plants >100 kW. Required flexible operations.
	2021 amendment	Designated specific tenders for biogases, restricted to Southern Germany.
	Jan 2025 amendment (Biomass Package)	Suspended the Southern restriction. Expanded tender volumes for biogas, increased flexibility bonus and adjusted flexibility requirements.
Gas Grid Access Regulation (GasNZV)	2010	Introduced basic grid connection regulations for biomethane plants.
Federal Fuel Emissions Trading Act (BEHG)	2019	Established an emissions trading system in heating and transport from 2021.
Buildings Energy Act (GEG)	2024 amendment	Made biomethane eligible for meeting renewable heating share targets in new buildings (65% in 2024, 100% by 2045). Raised the share of green gases from 15% in 2019 to 60% by 2040 in existing buildings.
Federal Emissions Control Act (BImSchG)	2024 amendment	Supported biomethane use in transport, setting GHG reduction quotas (8% reduction from 2010 level in 2023 and 25% in 2030).
CHP Act	Jan 2025 amendment	Extended subsidies for plants commissioned after 2026 and until 2030.

Germany's biogas and biomethane sectors are undergoing major changes, driven by the need to address profitability challenges in its ageing biogas fleet. Larger plants are shifting towards biomethane production, while smaller ones are exploring joint production models. For sites without grid access, compressed biomethane or bio-LNG for transport are emerging alternatives. The next few years will be crucial in determining the success of these transitions.

While Germany's 2024 NECP lacks a specific biomethane target, recent policy updates have renewed optimism. The transport market, once a key growth driver, is now facing low prices due to market distortions, but the industry and heating sectors remain promising. Electricity markets may also receive renewed interest. Maintaining current biogas output for biomethane production will be essential to meet the EU 35-bcm biomethane target by 2030. The forecast for 2025-2030 expects 2% combined growth, and a 19% increase in biomethane alone, revised down from last year's outlook to reflect the slowdown in 2024.

In the accelerated case, final-use demand for biogases could be higher in 2030 if they are used more extensively to support electricity grid flexibility.

Production of biogases in Germany, 2010-2030



Note: CHP = combined heat and power.

France

France is Europe's fastest-growing market, having many small to medium-sized agricultural plants (averaging 200 Nm³/h), all connected to the gas grid under the "right to inject" law. Biogas is widely seen as an agricultural support, with strong DSO/TSO engagement through grid zone planning and reverse-flow infrastructure. Public acceptance is high.

After using biomethane grid injection feed-in tariffs from 2011, France introduced tenders in 2024 for plants producing over 25 GWh/year. Due to low participation, however, these were replaced by blending obligations (Biogas Production Certificates), which will take effect in 2026 to support projects without relying on public funds.

Biomethane purchase agreements (BPAs) between energy companies and industry are also becoming popular. In France, BPAs cover unsubsidised biomethane and can help industries meet EU ETS requirements or transport tax incentives for biofuels, such as TIRUERT (Taxe Incitative Relative à l'Utilisation d'Énergie Renouvelable dans les Transports) or the newly proposed IRICC (Incitation à la Réduction de l'Intensité Carbone des Carburants).

Transport is the main growth driver. France has Europe's largest CNG truck fleet, with biomethane covering 39% of fuel use in 2023. The fleet continues to grow, with a 35% increase in the number of buses in 2022-2023 and 26% more trucks.

Under these currently favourable conditions, France's biogas and biomethane market is forecast to grow 71% during 2025-2030.

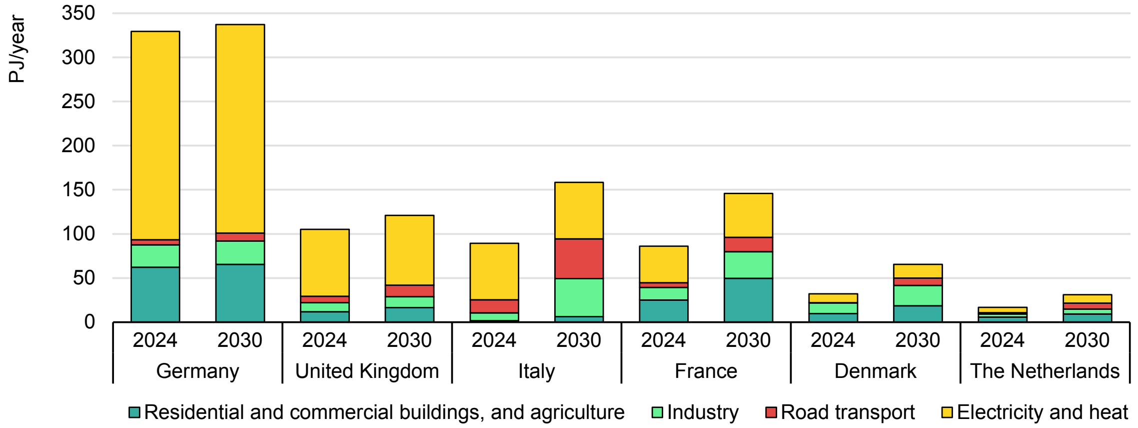
Main policies and regulations in France's biogas/biomethane sector

Policy	Year	Key information
Energy Transition for Green Growth Act (LTECV)	2016	Introduced the goal of 10% biomethane in the grid by 2030.
Pluriannual Energy Programme (PPE)	From 2019	Set targets of 24-32 TWh for 2028, of which 14-22 TWh would be injected.
Climate and Resilience Law	2021	Reinforced the right to inject biomethane into the natural gas grid, with 60% of the connection cost supported by TSOs/DSOs. Created biogas production certificates.
Decrees of 2020 and 2023	2020-2023	Established an auction scheme for new plants and conditions for purchase tariffs for biomethane grid injection. Maintained a feed-in tariff for projects below 25 GW/y only. In 2023, revised FiT prices upwards.
Tax on the Use of Renewable Energy in Transport (TIRUERT)	2023	Aligned taxation with GHG emission reductions in transport at a penalty of EUR 100/t CO_2, with biomethane for transport included from 2026.
Final updated NECP	2024	Increased the target to 50 TWh of biogases, of which 44 TWh would be injected by 2030.
Pluriannual Energy Programme, 2025-2035 (PPE3)	Nov 2024	Targeted 50-85 TWh of biomethane by 2035.
Mandate for Biogas Production Certificates (CPBs), Decree 2024-718.	2024	Obligated natural gas suppliers to submit CPBs, with targets for additional production in 2026 (0.8 TWh), 2027 (3.1 TWh) and 2028 (6.5 TWh).

Italy

Italy is the second-largest biogas market in Europe and one of the most dynamic ones, growing in both biogas and biomethane production. Nearly all biomethane is used in transport. It has the largest natural gas vehicle (NGV) fleet in Europe, with a 60% biomethane share. In Italy, the integration of different types of feedstocks is good, with municipal solid waste accounting for about 45% of biomethane feedstocks, the rest being agricultural.

Biogas production by country and end use for selected European countries, 2024 and 2030



We expect Italy's production of biogases to increase 77% over 2025-2030. However, despite ambitious NECP targets and strong policy support to convert biogas power plants to biomethane, growth has slowed over the past two years due to permitting and feedstock challenges. Short-term prospects remain uncertain, though the Italian government is taking action to increase investment interest.

Main policies and regulations in Italy's biogas/biomethane sector

Policy	Year	Key information
Ministerial Decree 2/3/2018	2018	Introduced support for biomethane in transport. Ended in 2023.
National Recovery and Resilience Plan (NRRP), Ministerial Decree 15/9/2022	2022	Extended biomethane support to all final uses (excluding power generation) for capital expenses and production tariffs for grid injections allocated via tenders, for new plants and biogas upgrades completed before June 2026.

Denmark

Denmark has the highest biomethane share among all EU gas grids (40% in 2025), and its target is to reach 100% green gases by 2030. The country's aim is to phase out gas use in households and to direct biomethane use to more hard-to-electrify industrial heat systems.

Despite strong development historically, a rise in feedstock costs (as well as other market conditions) slowed growth between 2023 and 2024. Several regulatory changes are being discussed in 2025, for instance an increase in gas distribution tariffs or the revision of gas CO_2 taxes, which may affect the market. However, our forecast expects growth of around 33 PJ (around 0.93 bcme) from 2025 to 2030.

Main policies and regulations in the biogas/biomethane sectors of other selected European countries

Policy	Year	Key information
United Kingdom		
Renewable Transport Fuel Obligation (RTFO)	2012	Specified shares of renewables for fuel suppliers in the transport sector.
Resources and Waste Strategy for England	2018	Aimed to increase municipal recycling rates to 65% and send less than 10% biodegradable waste to landfills by 2035.
Green Gas Support Scheme (GGSS)	2021	Introduced financial incentives and feed-in tariffs for new plants injecting biomethane into the grid in 2021-2025.
Green Gas Levy (GGL)	2021	Applied a tax to fossil fuel gas suppliers to fund the GGSS.
Domestic Renewable Heat Incentive (DRHI)	2014-2022	Awarded 7-year feed-in tariffs for renewable heating installations in households
Denmark		
Green Gas Strategy	2021	Targeted 100% green gas in the grid by 2035.
The Netherlands		
“Stimulering Duurzame Energie” (SDE++)	2020	Introduced a feed-in premium for renewable electricity production, including from biogas, and for green gases, including biomethane.
Green gas blending obligation (BMV)	Proposal for 2026	Will introduce yearly CO_2 reductions in the gas grid, to be achieved by blending of green gases, targeting 0.8 Mt CO_2 in 2026 and 3.8 Mt CO_2 by 2030. Obligated parties are users under the new ETS2. Green certificates will be tradable.

United States

The United States is the largest producer of biomethane (usually called renewable natural gas) globally, at around 136 PJ. Its market is one of the most dynamic ones, growing 2.2-fold since 2020 and accelerating since 2022 especially.

Although transportation use – as bio-CNG or bio-LNG for long-distance trucking – has driven this huge surge, other final uses are emerging, supported by leading states such as California.

Transportation

The use of renewable natural gas (RNG) in transportation has been the key driver of RNG supply growth in the past five years, with average year-on-year increases of 28%. This rise was made possible by the combination of three types of stackable incentives: federal tax credits, renewable identification numbers (RINs) in the Renewable Fuel Standard (RFS) and carbon credits from state-level low-carbon fuel standard programmes, particularly in California.

The **Inflation Reduction Act (IRA)** of 2022 extended investment tax credits to RNG projects (section 48), increasing the project pipeline for biogases. These credits were available to facilities beginning construction before the end of 2024. The 2025 **One Big Beautiful Bill Act (OBBBA)** has replaced the IRA budget and continues to support biogas and biomethane production. Production credits (section 45Z) have been extended to 2029, limiting eligibility to feedstocks from North America. Since RNG feedstocks are mostly local, this restriction is unlikely to impact the sector. The USD 1/gallon credit cap can be exceeded for manure-based RNG, depending on its carbon intensity.

In June 2025, the EPA proposed new renewable volume obligations (RVOs) for 2026-2027 under the RFS. Between 2022 and 2025, cellulosic biofuel D3 RIN obligations – 95% of which come from RNG – increased twofold. However, RIN generation fell short of targets in 2023-2024 and is expected to do so again in 2025.

The EPA has reduced the 2025 target and planned moderate 5.5% annual growth for the next two years. As explained in its draft regulatory impact analysis, the rapid growth of previous years has saturated transport markets in California and Oregon, with an overall US share of 86% RNG use in natural gas-powered vehicles. Supply is now demand-limited instead of production-limited. Recent technology developments of new, larger and more efficient natural gas engines could result in wider adoption of gas-powered long-haul trucks and boost RNG consumption in the transport sector.

California, the largest RNG market, amended its **Low Carbon Fuel Standard (LCFS)** in 2025, strengthening GHG emissions reduction targets from 13.75% to 22.75% in 2025 and from 20% to 30% in 2030. These new targets are expected to raise carbon credit prices. Methane avoidance credits that lead to ultra-low-emission manure-based RNG (averaging around -300 g CO_2/MJ) will be phased out by 2040. As highlighted in its 2022 Scoping Plan Update, California is preparing to transition from RNG use in transportation to using it in heating and hydrogen production in the long term as transport electrification advances.

Oregon and Washington also have clean fuel programmes, and other states – including Hawaii, Illinois, New York, Massachusetts, Michigan, Minnesota, New Jersey, New Mexico and Vermont – are considering similar policies.

Main policies and regulations in the US biogas/biomethane sector

Policy	Year	Key information
Federal regulations		
Renewable Fuel Standard (RFS) programme	2005	Required a minimum volume of renewable fuels in transportation fuel sold in the US.
Inflation Reduction Act (IRA)	2022	Established investment tax credits (ITCs) and production tax credits (PTCs) for renewable energy and alternative fuel projects for 10 years, for construction beginning before 2025.
Set Rule **Implementation (RFS)**	2023	Introduced renewable volume obligations for transport (RINs) for 2023, 2024 and 2025.
Partial Waiver **of 2024 Cellulosic Biofuel Volume Requirement**	Jun 2025	Partially waived the 2024 cellulosic biofuel volume requirement due to a shortfall in production.
Proposed RFS **for 2026 and 2027**	Jun 2025	Proposed renewable volume obligations for transport (RINs) for 2026 and 2027. Partially waived the 2025 cellulosic biofuel volume requirement due to a shortfall in production.
One Big Beautiful Bill Act (OBBBA)	Jul 2025	Modified tax credits under the IRA. Extended the Clean Fuel Production Tax Credit from end 2027 to end 2029. Restricted production to the United States and feedstocks to Mexico, the United States and Canada. RNG from animal manure can get credits above the cap at 1 USD/gal and is allowed to report negative carbon intensity scores.
State regulations		
California Low Carbon Fuel Standard (LCFS)	2007	Targeted 20% lower transport carbon intensity by 2030. Established annual carbon intensity (CI) standards and a trading system for carbon credits.
California Dairy Digester Research and Development Program	From 2014	Introduced by the Department of Food and Agriculture to offer grants for dairy digesters, max. 50% of total final cost. Applications accepted until October 2024 only.
California Renewable Gas Standard (RGS) procurement programme D.22-25-025 **implementing SB 1440**	2022	Mandated procurement targets for gas utilities, for gas produced from organic waste diverted from landfills (0.5 bcm/year by 2025) and from all feedstocks (about 12.2% or 2.06 bcm by 2030).

Policy	Year	Key information
California 2022 Scoping Plan Update	2022	Introduced a roadmap to achieve carbon neutrality by 2045. Established more ambitious GHG reduction targets.
California LCFS amendments	Jul 2025	Raised CI reduction targets from 13.75% to 22.75% for 2025, and from 20% to 30% by 2030. Introduced a new auto-acceleration mechanism in case targets are met. Methane avoidance credits for projects starting after 2029 will phase out in 2040 if RNG is used in transportation, and from 2045 if it is used for hydrogen production. Additional deliverability requirements will be added from 2041 (RNG for transportation) or from 2046 (RNG for hydrogen).
Oregon Clean Fuels Program	2016	Established an annual CI standard target. Differences from the standard generate or require credits.
Washington Clean Fuel Standard	2023	Established an annual CI standard target. Differences from the standard generate or require credits.
New Mexico Clean Transportation Fuel Program	Mar 2024	Established an annual CI standard target. Differences from the standard generate or require credits. The target is to reduce CI 20% by 2030 and 30% by 2040 compared to 2018.

Utilities and heat

Although transportation accounts for almost 60% of US RNG consumption, the market is expanding into non-transportation uses, leveraging its compatibility with existing natural gas infrastructure.

Legislative support is growing, with four states having enacted measures to promote RNG in residential and commercial sectors, including mandatory or voluntary blending targets and cost-recovery mechanisms for utilities. For instance, California's Senate Bill (SB) 1440 mandates 12.2% RNG by 2030, Oregon's SB 98 sets voluntary targets of up to 30% by 2050, and Nevada's SB 154 requires 3% by 2035.

Gas utilities are increasingly involved in RNG procurement and production, building interconnections and pursuing decarbonisation goals, often exceeding state mandates. S&P Global Commodity Insights projects that meeting all voluntary targets could raise supply from 0.07 Bcf/d in 2023 to 0.6 Bcf/d (around 6 bcm/y) by 2035.

Industrial customers are also turning to RNG to meet their voluntary ESG goals and offer "green" products to their clients. These buyers secure long-term contracts with RNG providers through BPAs, offering lower but more stable prices than transportation markets, which may help derisk investments. The industry sector could be a huge market for RNG.

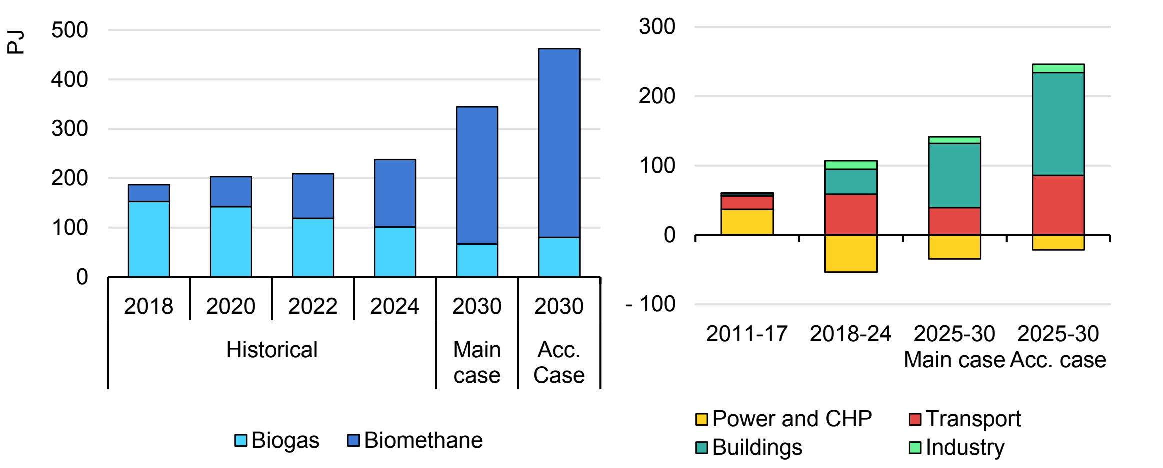
Forecast

Combined biogas and biomethane production is set to accelerate, growing 1.6 times by 2030 compared to the 2023 level. While biogas made up about 50% of output in 2023, 95% of new plants coming online are producing RNG. Growth is driven by increasing use in the transportation, residential and industry sectors.

Transportation remains the largest RNG consumer (currently nearly 60%), but growth in this sector is decelerating from 24% annually in 2022-2024 to about 13% in 2024-2030, as the RNG share in natural gas-powered vehicle fleets reaches saturation and gas fleet expansion slows. In the accelerated case, growth would be higher with the widescale adoption of new, larger engine models in gas-powered trucks.

In contrast, residential and commercial RNG demand is expected to grow rapidly – by around 43% annually – as state blending mandates and utilities' voluntary targets stimulate uptake. Industry demand is also expected to rise, especially after updated GHG Protocol guidance on RNG reporting via pipelines is released, likely by 2028.

Production of biogases in the United States, 2010-2030



Note: CHP = combined heat and power.

China

China has a long-standing tradition of biogas production. During the 2000s and 2010s, government subsidies enabled millions of farm households to install small-scale digesters, with installations peaking at 42 million units in 2015. Since then, however, the number of active units has declined due to maintenance difficulties (among other factors). In parallel, government support has shifted towards larger industrial-scale projects. In 2019, China introduced Guidelines for Promoting Development of the Biomethane Industry, which set ambitious bio-natural gas (BNG) output targets of 10 bcm by 2025 and 20 bcm by 2030.

Progress since then has been slower than anticipated, but policy updates aim to accelerate development. The 14th Five-Year Plan (2021-2025) called for the construction of large demonstration plants in regions with rich agricultural and livestock resources. A national standard for biogas plant design was also introduced in 2022, along with efforts to better integrate biogas production with other sectors such as waste collection. China's biogas strategy is also closely tied to broader goals, including rural development (as described in the Rural Energy Revolution plan, for example) and the increased use of organic fertilisers.

Regulation and incentives

China supports biogas and BNG development primarily through capital investment subsidies and tax exemptions for project developers. These incentives apply to all facilities independent of their end product (electricity generation, CHP, purification and grid-injectable gas for use in transport, industry, buildings and agriculture).

Despite the country's significant biogas potential, growth has been slow. According to actors in the sector, key barriers include technical difficulties when processing mixed feedstocks, challenges in connecting to gas and electricity networks, high feedstock costs, and the absence of incentives for ongoing production (current policies focus only on upfront investment). In contrast, other emerging markets have successfully used production-based subsidies (such as feed-in tariffs or premiums in long-term contracts) to encourage consistent plant operation, supporting the relatively high operating costs.

China's policy support has focused mainly on the supply side in the production of biogases, favouring feedstock collection and the integration of agricultural residues, animal manure and municipal organic waste. Due to gas infrastructure limitations in some areas with good feedstock potential, new plants have sometimes been planned in hubs that cover county areas to connect biogas production with end consumers.

China's government is working on establishing an official certificate trading system that includes BNG. In January 2024, it released a voluntary GHG emissions reduction trading system (CCER), but biomethane is not yet covered. In parallel, in December 2023 the Chinese Biomass Energy Industry Promotion Association (BEIPA) launched a voluntary certification platform for non-electrical energy uses of biomass. The development of a transparent and robust green certificate market would boost industry sector demand.

New investors

Despite last year's continuous but slow growth, several signals indicate acceleration. For instance, state-owned energy and gas companies such as PetroChina, Everbright Environment and Shenergy Environment have recently commissioned BNG plants. Foreign companies are also building new plants in China (Air Liquide is planning seven plants, and EnviTec Biogas AG has already built eight). The engineering and industry sector is quickly gaining know-how.

Demand growth

The main use of biogas today is for power generation (69% of biogases produced, if household production is excluded). According to published Government of China data on installed capacity, power generation from biogas is accelerating growth (22% increase between 2022 and 2023).

Main policies and regulations in China's biogas/biomethane sector

Policy	Year	Key information
Chinese Rural Household Biogas State Debt Project	2003	Aimed to reduce pollution from agricultural wastes and solve energy shortage in rural areas.
Working Plan of Upgrading and Transforming Rural Biogas Projects	2015	Promoted BNG pilot projects by the central government for the first time.
County Planning Outline on the Development and Utilisation of BNG	2017	Released by the National Energy Administration. Requested projects to be integrated into county energy planning.
Guidelines for Promoting Development of the Biomethane Industry	2019	Targeted 10 bcm by 2025 and 20 bcm by 2030.
14th Five-Year Plan **for the Development of Renewable Energy**	2021-2025	Introduced support for large-scale demo projects, and diversified feedstocks and planning of areas.
Action Plan for Methane Emissions Control	2023	Promoted the use of animal manure.
Action Plan for Pollution Prevention and Control in Agriculture and Rural Areas	2021-2025	Aimed to accelerate the treatment of rural domestic waste and wastewater.
Notice on the Rural Energy Revolution Pilot County Construction Plan	2023	Provided instructions for provincial development.
Guiding Opinions on Vigorously Implementing the Renewable Energy Substitution Initiative	2024	Aimed to increase renewable energy consumption.
Incentives		
Financial support for investments		Provides RMB 1 500/m^3 of digester volume, with a limit of 35% of investment.
Tax credit		Exempts companies from all corporate income tax for the first three years, and half for the following three.

Demand for biogas and BNG in the industry sector, for both energy and chemical uses, is rising. The first BPAs involving Chinese providers were signed in 2024. Additionally, industry stakeholders are considering using biomethane to produce low-emissions hydrogen and methanol. For example, Shenergy is building a green methanol plant in the Shanghai area. Starting operations in 2025, it will provide low-emissions fuel for Shanghai's maritime port.

Apart from methanol, China's shipping sector is exploring the use of bio-LNG in vessels. For example, COSCO Shipping Lines is investing in new LNG container ships. Bio-LNG demand for long-distance trucking is also surging.

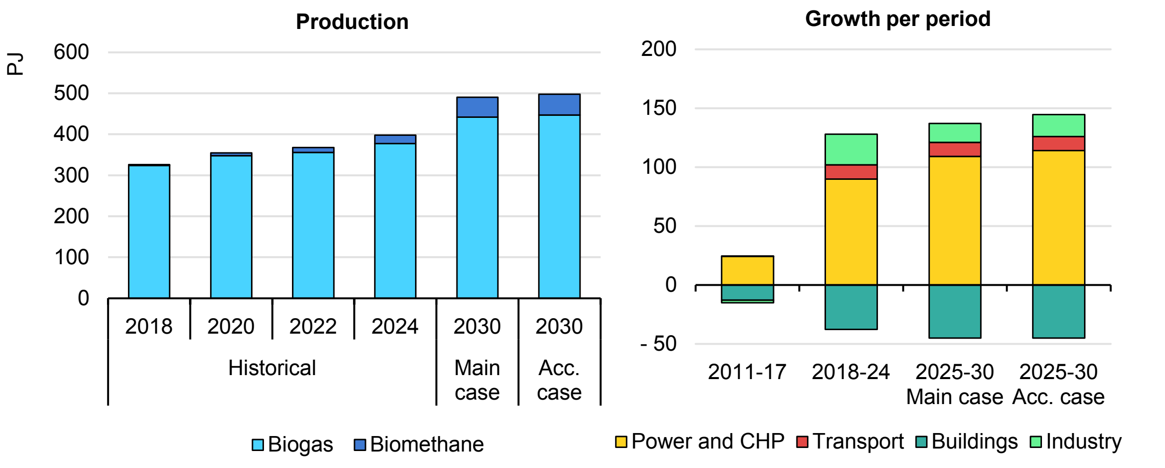
Forecast

With more newly installed capacity coming online each year, China's biogas and BNG output is expected to expand in upcoming years. However, sharper acceleration is anticipated after 2030 as infrastructure, grid access and large-scale feedstock collection challenges are addressed.

In our main case forecast, combined biogas and biomethane production rises 23% between 2025 and 2030. However, this figure is somewhat misleading, as it includes small household digesters, used for residential consumption, for which output is declining as they are increasingly being abandoned. When only medium- and large-scale projects are considered, growth is significantly stronger (around 80%).

Still, even with this momentum, reaching the government's 2030 target of 20 bcm (roughly 760 000 TJ) may be challenging. Our projections place total output at 12.8-13.0 bcm by that year.

Production of biogases in China, 2010-2030



Note: CHP = combined heat and power.

India

As part of its decarbonisation strategy, India aims to increase the share of natural gas in its energy mix from 6.7% in 2023 to 15% by 2030, reducing reliance on coal. To support this shift, the country is expanding its gas infrastructure under the One Nation One Gas Grid initiative.

Compressed biogas (CBG), with a methane content above 90%, is expected to play a key role in this transition – enhancing energy security by reducing dependence on LNG imports while also helping lower CO_2 and methane emissions.

Given India's feedstock potential, it could produce around 115 bcm of biogases, equivalent to 160% of its current natural gas consumption. Traditionally, India has had considerable biogas production from household facilities in rural areas, providing clean energy for cooking and lighting. Production from these small plants has been declining, however, and the government is targeting growth from larger, more efficient facilities.

Incentives and regulations

In recent years, India has rolled out robust policy measures to promote industrial biogas and CBG plant development. Launched in 2018, the Sustainable Alternative Towards Affordable Transportation (SATAT) initiative aimed to establish 5 000 new plants and produce 15 000 metric tonnes per year by fiscal year (FY) 2023-2024, supplying both the transport sector and city gas networks. Under SATAT, oil marketing companies must enter offtake agreements with CBG producers, with pricing and terms defined by the programme.

However, SATAT implementation has been significantly slower than anticipated. Only 113 plants had been commissioned by September 2025, with annual production reaching 24 310 tonnes. As a result, the production target timeline has been extended to FY 2025-2026 and incorporated into the broader Galvanising Organic Bio-Agro Resources (GOBARdhan) initiative. GOBARdhan is an interministerial programme that supports CBG plant development and the collection of organic waste in both rural and urban areas. In June 2023, it introduced a centralised registration portal for CBG projects.

Other national initiatives are in also place to support biogas development in India. These include the Waste to Energy Programme, which offers central financial assistance, and the National Biogas Programme targeting urban and semi-urban regions. In addition, some states have introduced their own incentives to promote biogas expansion. The new GOBARdhan umbrella aims to co-ordinate some of these benefits, which are currently scattered across various ministries and departments.

Despite this support, the sector still faces key challenges in ensuring financial viability for large-scale plants, obtaining feedstocks that have a consistent quality, and developing the supply chain. The Government of India is also working to diversify revenue streams for the biogas sector. In July 2023, it introduced carbon credit certificates for the voluntary carbon offset market. Financial incentives are provided for the collection and sale of fermented organic matter (FOM), which is used as an organic fertiliser.

Furthermore, India announced CBG blending mandates in November 2023. These require gas marketing companies to blend CBG into transport and domestic piped natural gas, starting at 1% in FY 2025-2026 and increasing to 5% by FY 2028-2029. These obligations are expected to significantly drive CBG supply growth.

New projects

Despite slower-than-expected growth, the pipeline for new projects is expanding quickly. At the beginning of October 2024, 871 plants were operational and 357 were completed or under construction in the GOBARdhan registry. Most registered plants are small-scale community facilities, but some large and very large plants are also planned.

Main policies and regulations in India's biogas/biomethane sector

Policy	Year	Key information
Sustainable Alternative Towards Affordable Transportation (SATAT) programme	2018	Issued by the Ministry of Petroleum and Natural Gas, targeting 5 000 large-scale biogas plants and 15 Mt/y production by FY 2023-24; purchase offtake agreements with oil and gas companies and fixed-purchase tariffs up to 2029; tax exemptions on some goods and services; financial assistance.
Waste to Energy Programme	2020, updated in 2022	Initiated by the Ministry of New and Renewable Energy. Aimed to increase energy production from urban, industrial and agricultural wastes and residues.
National Biogas Programme (NBP)	2022	Designed to promote construction of smaller plants (1-1 000 m^3) in rural and semi-rural areas.
Galvanising Organic Bio-Agro Resources (GOBARdhan) programme	2018	Initially designed to manage revalorisation of dung and dairy waste through cluster and community plants. Offered financial support and tax exemptions on equipment. In 2024, created a national registry of biogas plants, including SATAT plants.
Blending mandate obligation	Nov 2023	Mandated blending of compressed biogas in transport fuel and domestic piped gas, starting at 1% in FY 2025-26 and rising to 5% in FY 2028-29.

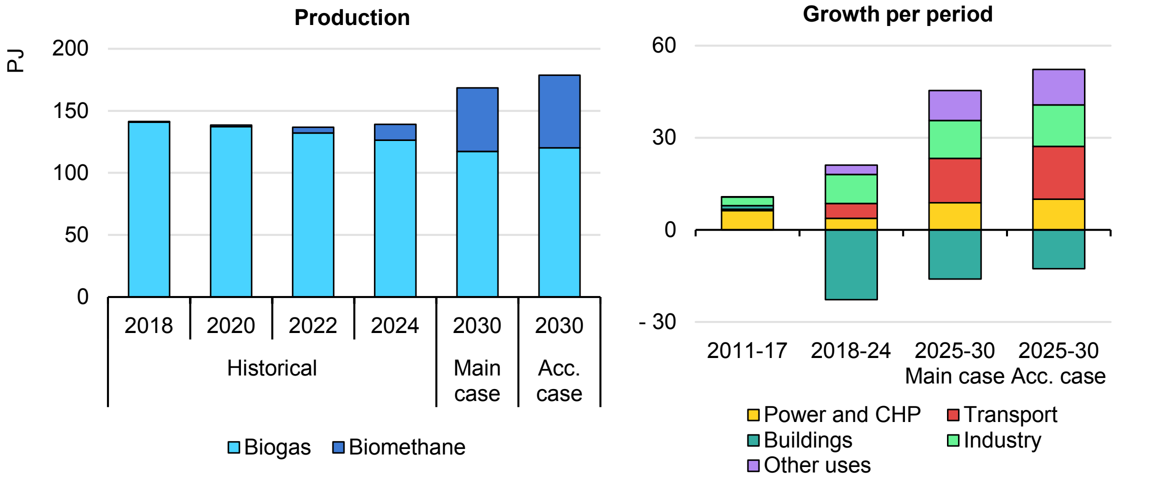
Furthermore, investment interest is rising among major companies, both national and foreign. Several joint ventures between oil and gas companies and engineering or operating CBG companies have been announced. Some have made public their plans to develop plants (the largest projects are RIL's 500 units in Andhra Pradesh, and BPCL's 200-300 units in several states).

Forecast

Main case expected growth for biogas and CBG combined is 21% between 2024 and 2030, around 20 PJ higher than last year's forecast for 2030. The forecast includes a decrease in production from small household facilities in rural areas, used for residential heating and cooking, as they are being abandoned. If production from these small plants is not taken into consideration, however, overall growth would be 103% in the main case and 119% in the accelerated case, reflecting a strong uptick in Indian market activity.

Transport is a growing end-use sector in India, with compressed natural gas fleets expanding rapidly. After a 24% increase in sales from 2024, the number of vehicles reached 7.5 million in 2025. The SATAT programme currently supports transport, and CBG is delivered in compressed cylinders or cascades when grid connection is not possible. Transport CBG consumption is thus expected to grow 3.7-fold in the main case during 2024-2030, and 4.2-fold in the accelerated case.

Production of biogases in India, 2010-2030



Note: CHP = combined heat and power.

Brazil

Brazil's biogas production potential is one of the world's largest. The IEA estimates that the country could generate 102 billion cubic metres of biogas equivalent (bcme) by using crop residues – mainly vinasse and filter cake from sugarcane processing – as well as corn and ethanol production residues, animal manure and biowaste.

Biogas and biomethane development align well with Brazil's policy priorities to decarbonise the energy sector, reduce fuel imports (both from natural gas and from diesel for transport use), support valorisation of waste and residues, and decrease methane emissions. Building on its experience and leadership in developing biofuels, Brazil has put a strong policy framework in place to encourage the production and use of biogas and biomethane.

One of the main drivers for growth is the Fuel of the Future law that sets GHG emissions reduction targets for gas producers and importers. Obligated parties can, among other options, purchase biomethane or green gas certificates to comply with the blending obligations. The programme starts in 2026 with a 1% reduction target that will gradually increase to 10%. Considering the natural gas consumption projections for Brazil, Cedigaz judges that meeting this target could require around 4 bcme of biomethane.

While this recently introduced law is mobilising investment in new production facilities, gas producers have also opened public calls to secure biomethane purchases. The market is attracting investment from national energy and bioenergy companies, as well as from international investors.

Final demand is expected to come mainly from industry and transport. Several long-term contracts have already been signed by industrial firms based in Brazil to use biomethane (or green certificates) to comply with the emissions trading system obligations. There is also interest in shifting private vehicle fleets to natural gas. In transport, most natural gas-powered vehicles are currently light passenger cars, but the number of trucks using CNG or LNG, now very small, is expected to grow significantly. An important share of biomethane use might also come from vehicles used in agriculture or in the sugarcane industry.

One of the greatest challenges to biomethane expansion in Brazil is the limited development of the natural gas grid. To valorise biogas produced in remote locations, the options are to generate electricity with it; use it internally; or upgrade it to biomethane and transport it to the gas distribution grid by truck. Gas distributors and biomethane producers are collaborating on the creation of new infrastructure such as green corridors to connect producing areas with the main pipelines or consumption zones.

Brazil's immense feedstock potential together with its political determination to support market growth make its prospects for scaled-up production of biogases promising.

Main policies and regulations in Brazil's biogas/biomethane sector

Policy	Year	Key information
Special Incentives Regime for Infrastructure Development	2022	In Normative Ordinance 37, included biomethane within project types eligible for tax exemption for materials and equipment under the REIDI scheme.
National Methane Emissions Reduction Programme	2022	Promoted biogas and biomethane growth. Encouraged methane credits in the carbon market.
Fuel of the Future Law	2024	Mandated natural gas producers to reduce their GHG emissions by transitioning to biomethane (self-production or purchase of certificates). Required the GHG emissions reduction target to be set annually, starting at 1% in 2026 compared to the past 10-year average.
Decree No. 12, 614/2025	Sep 2025	Regulated the national decarbonisation programme for natural gas producers and importers and the incentive for biomethane uptake, including the issuance of CGOBs (Biomethane Guarantee of Origin Certificates).

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