Renewables

2023

Analysis and forecast to 2028

INTERNATIONAL ENERGY AGENCY

The IEA examines the full spectrum of energy issues including oil, gas and coal supply and demand, renewable energy technologies, electricity markets, energy efficiency, access to energy, demand side management and much more. Through its work, the IEA advocates policies that will enhance the reliability, affordability and sustainability of energy in its 31 member countries, 13 association countries and beyond.

IEA member countries:

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

The European Commission also participates in the work of the IEA

IEA association countries:

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

This publication and any map included herein are without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

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

Revised version, Jan 2024
Information notice found at: www.iea.org/corrections

Abstract

Renewables 2023 is the IEA's primary analysis on the sector, based on current policies and market developments. It forecasts the deployment of renewable energy technologies in electricity, transport and heat to 2028 while also exploring key challenges to the industry and identifying barriers to faster growth.

At the COP28 climate change conference in Dubai, more than 130 national governments including the European Union agreed to work together to triple the world's installed renewable energy capacity to at least 11 000 GW by 2030. Renewables 2023 provides detailed country-level analysis on the progress towards the global tripling target. Alongside the report, an online dashboard is also available, which maps all the relevant data to measure renewable energy deployment through 2028.

In addition to its detailed market analysis and forecasts, Renewables 2023 also examines key developments for the sector including policy trends driving deployment; solar PV manufacturing; competitiveness of renewable technologies; energy storage; renewable energy capacity for hydrogen production; the prospects for renewable energy companies; system integration and a special section on biogas and biomethane forecast.

IEA. CC BY 4.0.

Acknowledgements, contributors and credits

This study was prepared by the Renewable Energy Division in the Directorate of Energy Markets and Security. It was designed and directed by Heymi Bahar, Senior Analyst.

The report benefited from analysis, drafting and input from multiple colleagues. The lead authors of the report were, Yasmina Abdelilah, Ana Alcalde Báscones Heymi Bahar, Piotr Bojek, François Briens, Trevor Criswell, Jeremy Moorhouse, and Laura Mari Martinez, who was also responsible for data management. The report also benefited from analysis and drafting from Kartik Veerakumar.

Paolo Frankl, Head of the Renewable Energy Division, provided strategic guidance and input to this work. Valuable comments, feedback and guidance were provided by other senior management and numerous other colleagues within the IEA, in particular, Keisuke Sadamori, Laura Cozzi, Tim Gould, Timur Gül, Brian Motherway, Dan Dorner and Dennis Hessling

Other IEA colleagues who have made important contributions to this work include:

Nadim Abillama, Sylvia Beyer, Eren Cam, Hana Chambers, Chiara Delmastro, Syrine El Abed, Pablo Hevia-Koch, Zoe, Hungerford, Luca Lorenzoni, Yannick Monschauer, Taylor Morrison, Brian Motherway, Thomas Spencer, Brent Wanner, Biqing Yang and Peter Zeniewski.

Timely data from the IEA Energy Data Centre were fundamental to the report, with particular assistance provided by Pedro Carvalho, Luca Lorenzoni, Taylor Morrison, Nick Johnstone, Julian Prime and Roberta Quadrelli.

This work benefited from extensive review and comments from the IEA Standing Group on Long-Term Co-operation, IEA Renewable Energy Working Party, members of the Renewable Industry Advisory Board (RIAB) and experts from IEA partner countries and other international institutions. The work also benefited from feedback by the IEA Committee on Energy Research and Technology, IEA Technology Collaboration Programmes (IEA TCPs).

Many experts from outside of the IEA provided valuable input, commented and reviewed this report. They include:

IEA. CC BY 4.0.

Countries

Canada (Natural Resources Canada), China (Energy Research Institute – ERI), Denmark (Ministry of Climate, Energy and Utilities), European Union (European Commission – DG Energy), Finland (Ministry of Economic Affairs and Employment), Germany (Federal Ministry for Economic Affairs and Climate Action of Germany), Japan (Ministry of Economy, Trade and Industry – METI), Spain (Institute for Energy Diversification and Energy Saving – IDAE), and the United States of America (Department of Energy).

Technology Collaboration Programmes (TCPs)

Bioenergy TCP, Heat Pumping Technologies (HPT) TCP, Geothermal TCP, Hydrogen TCP Hydropower TCP, Ocean TCP, Photovoltaic Power Systems (PVPS) TCP, Solar Heating and Cooling (SHC) TCP, SolarPACES TCP, Wind Energy TCP.

Other Organisations

Archer Daniels Midland Company (ADM), BP, Enel, European Commission, European Heat Pump Association (EHPA), European Renewable Ethanol Association (EPURE), European Solar Thermal Industry Federation (ESTIF), EU Ethanol Industry Association, Global Wind Energy Council (GWEC), Iberdrola, International Air Transport Association (IATA), J-Power, National Renewable Energy Laboratory (NREL), Neste, Ørsted, RNG Coalition, Siemens Gamesa Renewable Energy, SolarPower Europe, Solrico, SPV Market Research, The Energy and Resources Insitute (TERI), US Grains Council, Vestas, WindEurope, World Bioenergy Association, World Biogas Association and Yangtze Institute for Solar Technologies (YIST).

The authors would also like to thank Kristine Douaud for skilfully editing the manuscript and the IEA Communication and Digital Office, in particular Jon Custer, Astrid Dumond, Grace Gordon, Jethro Mullen, Isabelle Nonain-Semelin Robert Stone, Sam Tarling, Clara Vallois, Lucile Wall and Therese Walsh for their assistance. In addition, Ivo Letra from the Office of Management and Administration supported data management.

Questions or comments?

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

IEA. CC BY 4.0.

Table of contents

IEA. CC BY 4.0.

Executive Summary

2023 saw a step change in renewable capacity additions, driven by China's solar PV market

Global annual renewable capacity additions increased by almost 50% to nearly 510 gigawatts (GW) in 2023, the fastest growth rate in the past two decades. This is the 22nd year in a row that renewable capacity additions set a new record. While the increases in renewable capacity in Europe, the United States and Brazil hit all-time highs, China's acceleration was extraordinary. In 2023, China commissioned as much solar PV as the entire world did in 2022, while its wind additions also grew by 66% year-on-year. Globally, solar PV alone accounted for three-quarters of renewable capacity additions worldwide.

Achieving the COP28 target of tripling global renewable capacity by 2030 hinges on policy implementation

Prior to the COP28 climate change conference in Dubai, the International Energy Agency (IEA) urged governments to support five pillars for action by 2030, among them the goal of tripling global renewable power capacity. Several of the IEA priorities were reflected in the Global Stocktake text agreed by the 198 governments at COP28, including the goals of tripling renewables and doubling the annual rate of energy efficiency improvements every year to 2030. Tripling global renewable capacity in the power sector from 2022 levels by 2030 would take it above 11 000 GW, in line with IEA's Net Zero Emissions by 2050 (NZE) Scenario.

Under existing policies and market conditions, global renewable capacity is forecast to reach 7 300 GW by 2028. This growth trajectory would see global capacity increase to 2.5 times its current level by 2030, falling short of the tripling goal. Governments can close the gap to reach over 11 000 GW by 2030 by overcoming current challenges and implementing existing policies more quickly. These challenges fall into four main categories and differ by country: 1) policy uncertainties and delayed policy responses to the new macroeconomic environment; 2) insufficient investment in grid infrastructure preventing faster expansion of renewables; 3) cumbersome administrative barriers and permitting procedures and social acceptance issues; 4) insufficient financing in emerging and developing economies. This report's accelerated case shows that addressing those challenges can lead to almost 21% higher growth of renewables, pushing the world towards being on track to meet the global tripling pledge.

IEA. CC BY 4.0.

What is needed to reach the collective target to triple renewables by 2030 varies significantly by country and region. G20 countries account for almost 90% of global renewable power capacity today. In the accelerated case, which assumes enhanced implementation of existing policies and targets, the G20 could triple their collective installed capacity by 2030. As such, they have the potential to contribute significantly to tripling renewables globally. However, to achieve the global goal, the rate of new installations needs to accelerate in other countries, too, including many emerging and developing economies outside the G20, some of which do not have renewable targets and/or supportive policies today.

The global power mix will be transformed by 2028

The world is on course to add more renewable capacity in the next five years than has been installed since the first commercial renewable energy power plant was built more than 100 years ago. In the main case forecast in this report, almost 3 700 GW of new renewable capacity comes online over the 2023-2028 period, driven by supportive policies in more than 130 countries. Solar PV and wind will account for 95% of global renewable expansion, benefiting from lower generation costs than both fossil and non-fossil fuel alternatives.

Over the coming five years, several renewable energy milestones are expected to be achieved:

- In 2024, wind and solar PV together generate more electricity than hydropower.
- In 2025, renewables surpass coal to become the largest source of electricity generation.
- Wind and solar PV each surpass nuclear electricity generation in 2025 and 2026 respectively.
- In 2028, renewable energy sources account for over 42% of global electricity generation, with the share of wind and solar PV doubling to 25%.

China is the world's renewables powerhouse

China accounts for almost 60% of new renewable capacity expected to become operational globally by 2028. Despite the phasing out of national subsidies in 2020 and 2021, deployment of onshore wind and solar PV in China is accelerating, driven by the technologies' economic attractiveness as well as supportive policy environments providing long-term contracts. Our forecast shows that China is expected to reach its national 2030 target for wind and solar PV installations this year, six years ahead of schedule. China's role is critical in reaching the global goal of tripling renewables because the country is expected to install more than half of the new capacity required globally by 2030. At the end of the forecast period, almost half of China's electricity generation will come from renewable energy sources.

IEA. CC BY 4.0.

The US, the EU, India and Brazil remain bright spots for onshore wind and solar PV growth

Solar PV and onshore wind additions through 2028 is expected to more than double in the United States, the European Union, India and Brazil compared with the last five years. Supportive policy environments and the improving economic attractiveness of solar PV and onshore wind are the primary drivers behind this acceleration. In the European Union and Brazil, growth in rooftop solar PV is expected to outpace large-scale plants as residential and commercial consumers seek to reduce their electricity bills amid higher prices. In the United States, the Inflation Reduction Act has acted as a catalyst for accelerated additions despite supply chain issues and trade concerns in the near term. In India, an expedited auction schedule for utility-scale onshore wind and solar PV along with improved financial health of distribution companies is expected to deliver accelerated growth.

Renewable energy expansion also starts accelerating in other regions of the world, notably the Middle East and North Africa, owing mostly to policy incentives that take advantage of the cost-competitiveness of solar PV and onshore wind power. Although renewable capacity growth picks up in sub-Saharan Africa, the region still underperforms considering its resource potential and electrification needs.

Solar PV prices plummet amid growing supply glut

In 2023, spot prices for solar PV modules declined by almost 50% year-on-year, with manufacturing capacity reaching three times 2021 levels. The current manufacturing capacity under construction indicates that the global supply of solar PV will reach 1 100 GW at the end of 2024, with potential output expected to be three times the current forecast for demand. Despite unprecedented PV manufacturing expansion in the United States and India driven by policy support, China is expected to maintain its 80-95% share of global supply chains (depending on the manufacturing segment). Although developing domestic PV manufacturing will increase the security of supply and bring economic benefits to local communities, replacing imports with more expensive production in the United States, India and the European Union will increase the cost of overall PV deployment in these markets.

Onshore wind and solar PV are cheaper than both new and existing fossil fuel plants

In 2023, an estimated 96% of newly installed, utility-scale solar PV and onshore wind capacity had lower generation costs than new coal and natural gas plants. In addition, three-quarters of new wind and solar PV plants offered cheaper power than existing fossil fuel facilities. Wind and solar PV systems will

IEA. CC BY 4.0.

become more cost-competitive during the forecast period. Despite the increasing contribution needs for flexibility and reliability to integrate variable renewables, the overall competitiveness of onshore wind and solar PV changes only slightly by 2028 in Europe, China, India and the United States.

The new macroeconomic environment presents further challenges that policy makers need to address

In 2023, new renewable energy capacity financed in advanced economies was exposed to higher base interest rates than in China and the global average for the first time. Since 2022, central bank base interest rates have increased from below 1% to almost 5%. In emerging and developing economies, renewables developers have been exposed to higher interest rates since 2021, resulting in higher costs hampering faster expansion of renewables.

The implications of this new macroeconomic environment are manifold for both governments and industry. First, inflation has increased equipment costs for onshore and offshore wind and partly for solar PV (excluding module costs). Second, higher interest rates are increasing the financing costs of capital-intensive variable renewable technologies. Third, policy has been relatively slow to adjust to the new macroeconomic environment due in part to expectations that cost reductions would continue together with permitting challenges. This has left several auctions in advanced economies undersubscribed, particularly in Europe. Additionally, some developers whose power purchase contracts were signed prior to these macroeconomic changes have had to cancel their projects. Efforts to improve auction design and contract indexation methodologies are needed to resolve these challenges and unlock additional wind and solar PV deployment.

The renewable energy industry, particularly wind, is grappling with macroeconomic challenges affecting its financial health – despite a history of financial resilience. The wind industry has experienced a significant decline in market value as European and North American wind turbine manufacturers have seen negative net margins for seven consecutive quarters due to volatile demand, limited raw material access, economic challenges, and rising interest rates. To address these issues, the European Union launched a Wind Power Action Plan in October 2023, aiming to enhance competitiveness, improve auction design, boost clean technology investment, streamline permitting, and ensure fair competition. Chinese wind turbine manufacturers, benefiting from strong domestic demand and vertical integration, remain relatively stable amid global challenges.

IEA. CC BY 4.0.

The forecast for wind capacity additions is less optimistic outside China, especially for offshore

The wind industry, especially in Europe and North America is facing challenges due to a combination of ongoing supply chain disruptions, higher costs and long permitting timelines. As a result of these challenges, the forecast for onshore wind outside of China has been revised downwards as overall project development has been slower than expected.

Offshore wind has been hit hardest by the new macroeconomic environment, with its expansion through 2028 revised down by 15% outside China. The challenges facing the industry particularly affect offshore wind, with investment costs today more than 20% higher than only a few years ago. In 2023, developers have cancelled or postponed 15 GW of offshore wind projects in the United States and the United Kingdom. For some developers, pricing for previously awarded capacity does not reflect the increased costs facing project development today, which reduces project bankability.

Faster deployment of variable renewables increases integration and infrastructure challenges

The share of solar PV and wind in global electricity generation is forecast to double to 25% in 2028 in our main case. This rapid expansion in the next five years will have implications for power systems worldwide. In the European Union, annual variable renewables penetration in 2028 is expected to reach more than 50% in seven countries, with Denmark having around 90% of wind and solar PV in its electricity system by that time. Although EU interconnections help integrate solar PV and wind generation, grid bottlenecks will pose significant challenges and lead to increased curtailment in many countries as grid expansion cannot keep pace with accelerated installation of variable renewables.

Current hydrogen plans and implementation don’t match

Renewable power capacity dedicated to hydrogen-based fuel production is forecast to grow by 45 GW between 2023 and 2028, representing only an estimated 7% of announced project capacity for the period. China, Saudi Arabia and the United States account for more than 75% of renewable capacity for hydrogen production by 2028. Despite announcements of new projects and pipelines, the progress in planned projects has been slow. We have revised down our forecasts for all regions except China. The main reason is the slow pace of bringing planned projects to final investment decisions due to a lack of off-takers and the impact of higher prices on production costs. The development of an international hydrogen market is a key uncertainty affecting the forecast, particularly for markets that have limited domestic demand for hydrogen.

IEA. CC BY 4.0.

Biofuel deployment is accelerating and diversifying more into renewable diesel and biojet fuel

Emerging economies, led by Brazil, dominate global biofuel expansion, which is set to grow 30% faster than over the last five years. Supported by robust biofuel policies, increasing transport fuel demand and abundant feedstock potential, emerging economies are forecast to drive 70% of global biofuel demand growth over the forecast period. Brazil alone accounts for 40% of biofuel expansion to 2028. Stronger policies are the primary driver of this growth as governments expand efforts to provide affordable, secure and low-emission energy supplies. Biofuels used in the road transport sector remain the primary source of new supply, accounting for nearly 90% of the expansion.

Electric vehicles (EVs) and biofuels are proving to be a powerful complementary combination for reducing oil demand. Globally, biofuels and renewable electricity used in EVs are forecast to offset 4 million barrels of oil-equivalent per day by 2028, which is more than 7% of forecast oil demand for transport. Biofuels remain the dominant pathway for avoiding oil demand in the diesel and jet fuel segments. EVs outpace biofuels in the gasoline segment, especially in the United States, Europe and China.

Aligning biofuels with a net zero pathway requires a huge increase in the pace of deployment

This report's main case forecast is not in line with the near tripling of biofuels demand by 2030 seen in the IEA's Net Zero Emissions by 2050 (NZE) Scenario. In the aviation sector for instance, the NZE Scenario would require 8% of fuel supply coming from biojet fuel by 2030, while existing policies in this forecast will only bring biojet fuel's share to 1% by 2028. Bridging this gap requires new and stronger policies, as well as diversification of feedstocks.

Much faster biofuel deployment is possible through new policies and addressing supply chain challenges. In this report's accelerated case, biofuel supply growth is nearly triple that of the main case, closing the gap with the NZE Scenario by nearly 40%. Nearly half of this additional growth, almost 30 billion litres, is driven by strengthened policies in existing markets such as the United States, Europe and India. Another 20 billion litres comes mainly from biodiesel in India and ethanol in Indonesia. Biojet fuel offers a third growth avenue, expanding to cover nearly 3.5% of global aviation fuels, up from 1% in the main case. Fuels made from waste and residues also grow four times faster in the accelerated case.

IEA. CC BY 4.0.

Renewable heat accelerates amid high energy prices and policy momentum – but not enough to curb emissions

Modern renewable heat consumption expands by 40% globally during the outlook period, rising from 13% to 17% of total heat consumption. These developments come predominantly from the growing reliance on electricity for process heat – notably with the adoption of heat pumps in non-energy-intensive industries – and the deployment of electric heat pumps and boilers in buildings, increasingly powered by renewable electricity. China, the European Union and the United States lead these trends, owing to supportive policy environments; updated targets in the European Union and China; strong financial incentives in many markets; the adoption of renewable heat obligations; and fossil fuel bans in the buildings sector.

However, the trends to 2028 are still largely insufficient to tackle the use of fossil fuels for heat and put the world on track to meet Paris Agreement goals. Without stronger policy action, the global heat sector alone between 2023 and 2028 could consume more than one-fifth of the remaining carbon budget for a pathway aligned with limiting global warming to 1.5°C. Global renewable heat consumption would have to rise 2.2 times as quickly and be combined with wide-scale demand-side measures and much larger energy and material efficiency improvements to align with the NZE Scenario.

IEA. CC BY 4.0.

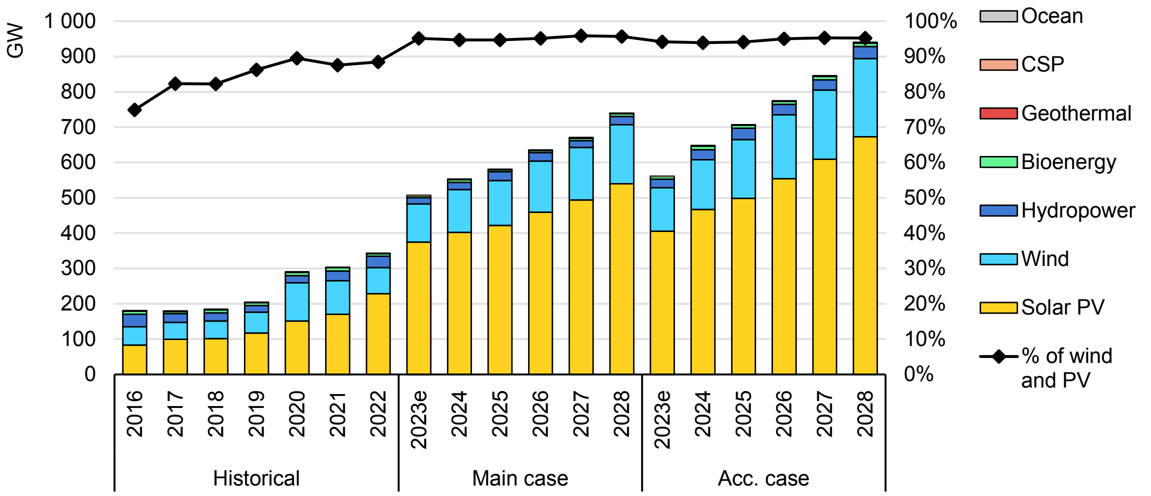
Chapter 1. Electricity

Global forecast summary

2023 marks a step change for renewable power growth over the next five years

Renewable electricity capacity additions reached an estimated 507 GW in 2023, almost 50% higher than in 2022, with continuous policy support in more than 130 countries spurring a significant change in the global growth trend. This worldwide acceleration in 2023 was driven mainly by year-on-year expansion in the People's Republic of China's (hereafter "China") booming market for solar PV (+116%) and wind (+66%). Renewable power capacity additions will continue to increase in the next five years, with solar PV and wind accounting for a record 96% of it because their generation costs are lower than for both fossil and non-fossil alternatives in most countries and policies continue to support them.

Renewable electricity capacity additions by technology and segment



IEA. CC BY 4.0.

Notes: CSP = concentrated solar power. Capacity additions refer to net additions. Historical and forecast solar PV capacity may differ from previous editions of the renewable energy market report. This year, 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. The DC electricity 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 in utility-scale installations. Solar PV and wind additions include capacity dedicated to hydrogen production.

IEA. CC BY 4.0.

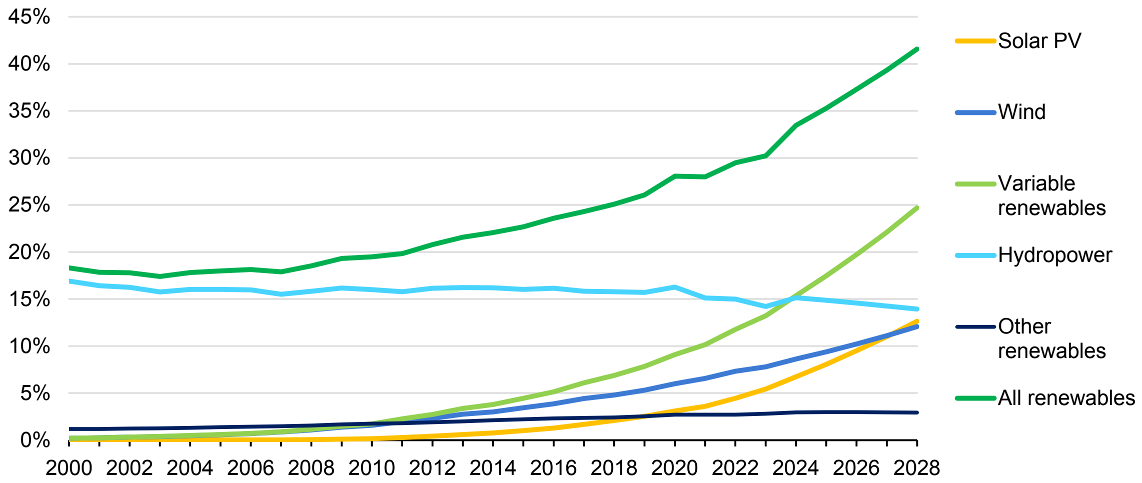
Solar PV and wind additions are forecast to more than double by 2028 compared with 2022, continuously breaking records over the forecast period to reach almost 710 GW. At the same time, hydropower and bioenergy capacity additions will be lower than during the last five years as development in emerging economies decelerates, especially in China.

Renewables overtake coal in early-2025 to become the largest energy source for electricity generation globally

By 2028, potential renewable electricity generation is expected to reach around 14 400 TWh, an increase of almost 70% from 2022. Over the next five years, several renewable energy milestones could be achieved:

- In 2024, variable renewable generation surpasses hydropower.
- In 2025, renewables surpass coal-fired electricity generation.
- In 2025, wind surpasses nuclear electricity generation.
- In 2026, solar PV surpasses nuclear electricity generation.
- In 2028, solar PV surpasses wind electricity generation.

Electricity generation by technology, 2000-2028



IEA. CC BY 4.0.

Notes: Electricity generation from wind and solar PV indicate potential generation including current curtailment rates. However, it does not project future curtailment of wind and solar PV, which may be significant in a few countries by 2028. The Curtailment section below discusses some of these recent trends.

Over the forecast period, potential renewable electricity generation growth exceeds global demand growth, indicating a slow decline in coal-based generation while natural gas remains stable. In 2028, renewable energy sources account for 42% of global electricity generation, with the wind and solar PV share making up 25%. In 2028, hydropower remains the largest renewable electricity source. However, renewable electricity generation needs to expand more quickly in many

IEA. CC BY 4.0.

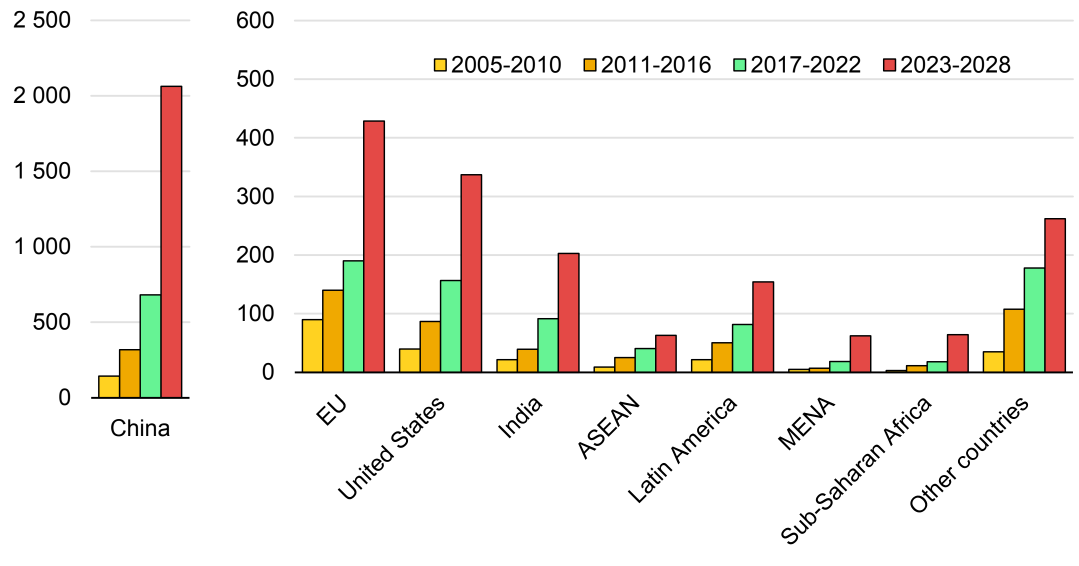
countries (see Net Zero Emissions by 2050 Scenario tracking section in this chapter).

While renewables are currently the largest energy source for electricity generation in 57 countries, mostly thanks to hydropower, these countries represent just 14% of global power demand. By 2028, 68 countries will have renewables as their main power generation source but still only account for 17% of global demand.

China is in the driver's seat

China's renewable electricity capacity growth t triples in the next five years compared with the previous five, with the country accounting for an unprecedented 56% of global expansion. Over 2023-2028, China will deploy almost four times more renewable capacity than the European Union and five times more than the United States, which will remain the second- and third-largest growth markets. The Chinese government's Net Zero by 2060 target, supported by incentives under the 14th Five-Year Plan (2021-2025) and the ample availability of locally manufactured equipment and low-cost financing, stimulate the country's renewable power expansion over the forecast period.

Renewable electricity capacity growth by country/region, main case



IEA. CC BY 4.0.

Notes: ASEAN = Association of Southeast Asian Nations. MENA = Middle East and North Africa. Capacity additions refer to net additions.

Meanwhile, expansion accelerates in the United States and the European Union thanks to the US Inflation Reduction Act (IRA) and country-level policy incentives supporting EU decarbonisation and energy security targets. In India, progressive policy improvements to remedy auction participation, financing and distributed solar PV challenges pay off with faster renewable power growth through 2028. In

IEA. CC BY 4.0.

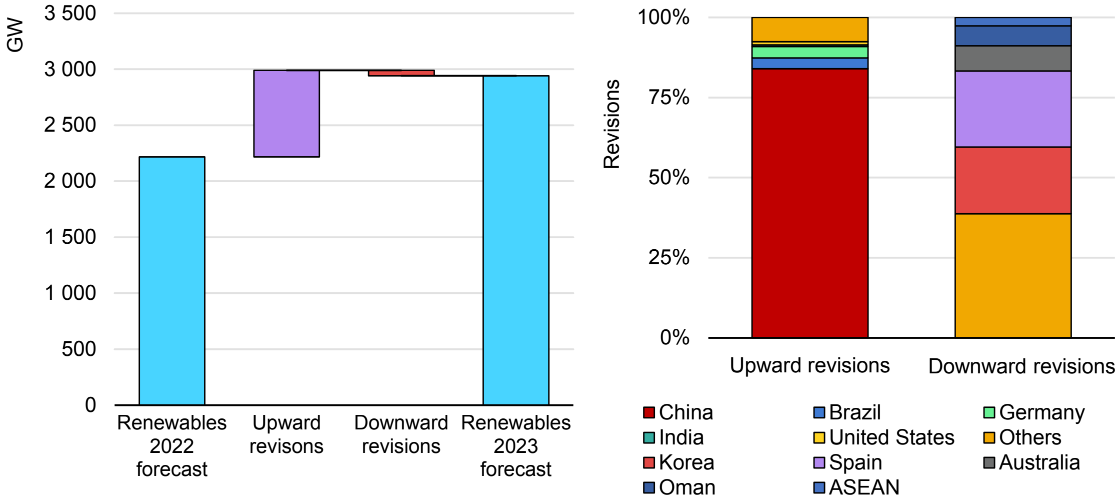
Latin America, higher retail prices spur distributed solar PV system buildouts, and supportive policies for utility-scale installations in Brazil boost renewable energy growth to new highs.

Renewable energy expansion also accelerates in the Middle East and North Africa, owing mostly to policy incentives that take advantage of the cost-competitiveness of solar PV and onshore wind power. Although renewable capacity increases more quickly in sub-Saharan Africa, the region still underperforms considering its resource potential and electrification needs.

The forecast has been revised upwards, but country and technology trends vary

We have revised the global *Renewables 2023* forecast up by 33% (or 728 GW) from our December 2022 publication. For most countries and regions, this revision reflects policy changes and improved economics for large-scale wind and solar PV projects, but also faster consumer adoption of distributed PV systems in response to higher electricity prices. Overall, China accounts for the most significant upward revisions for all technologies except bioenergy for power, for which reduced government support, feedstock limitations and complicated logistics remain challenging.

Renewable electricity capacity forecast revisions by country, 2023-2027, *Renewables 2023* vs *Renewables 2022*



IEA. CC BY 4.0.

Notes: ASEAN = Association of Southeast Asian Nations. Capacity additions refer to net additions. Comparison periods are the forecasts for 2023 to 2027.

Despite regulatory changes to its net metering scheme, Brazil's distributed PV capacity growth is exceeding our expectations, leading to noticeable upward revisions. For other countries, a more optimistic outlook result from policy

IEA. CC BY 4.0.

improvements for auction design and permitting, and a growing corporate PPA market in Germany; positive impacts of IRA incentives in the United States; and speedier streamlined renewable energy auctioning in India.

Conversely, we have revised down the forecast for Korea because the government's policy focus has shifted from renewables to nuclear energy, reducing solar PV targets. We have also reined in forecast growth for other markets compared with last year's outlook: for Spain because renewable energy auctions have been significantly undersubscribed; for Australia due to slow progress in large-scale renewable capacity for hydrogen production and the Expanded Capacity Investment Scheme only being announced towards the end of this report's development; for Oman because development time frames for large-scale renewable energy projects have been longer than expected, including for green hydrogen; and for multiple ASEAN countries as a result of sustained policy uncertainty as well as overall power supply gluts limiting additional renewable deployment in the short term.

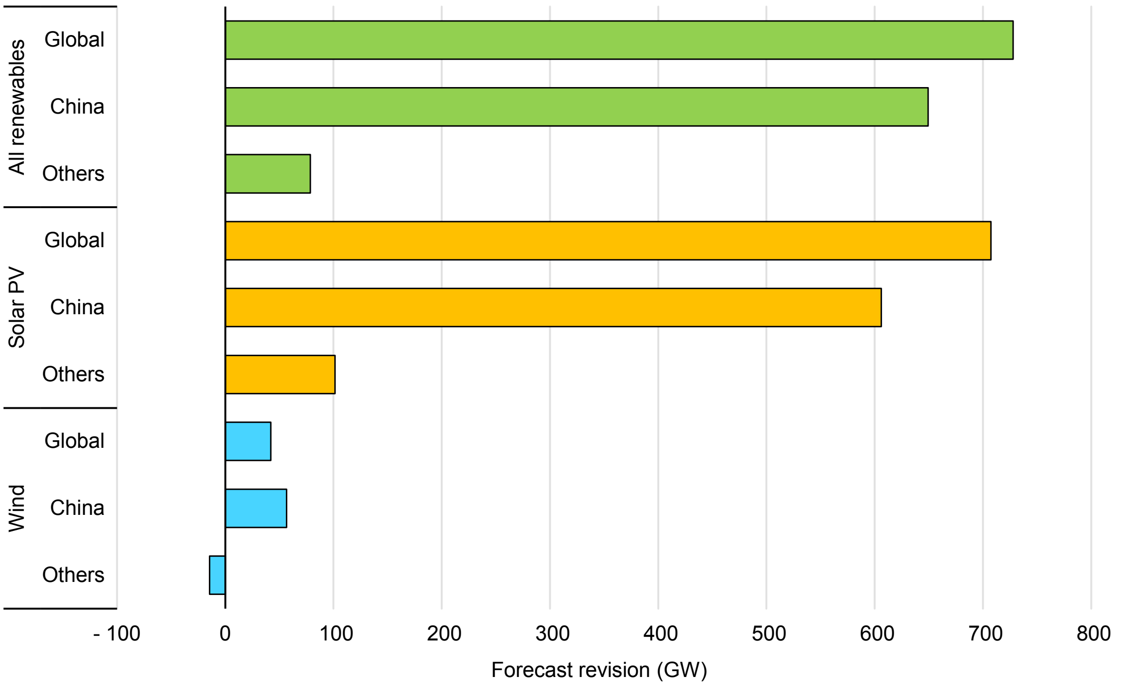
China's substantial upward forecast revision for PV hides slower progress in other countries

Overall, China's forecast has been revised up by 64% thanks to the country's improved policy environment and the growing economic attractiveness of solar PV and wind systems. For other countries, however, this year's forecast is almost 7% higher than our December 2022 outlook. China accounts for almost 90% of the global upward forecast revision, consisting mainly of solar PV. In fact, its solar PV manufacturing capabilities have almost doubled since last year, creating a global supply glut. This has reduced local module prices by nearly 50% from January to December 2023, increasing the economic attractiveness of both utility-scale and distributed solar PV projects.

Thus, even with the phaseout of subsidies, developers have been accelerating the deployment of utility-scale and commercial solar PV applications to meet growing power demand because it is more affordable than investing in new and existing coal- and gas-fired generation. In addition, China's government has clarified its green certificate rules, providing additional revenues for renewable energy projects. Similar policy improvements also support a higher wind forecast, but longer project lead times, especially for the growing offshore wind market, limits upward revision.

IEA. CC BY 4.0.

Renewable electricity capacity forecast revisions, *Renewables 2023* vs *Renewables 2022*



IEA. CC BY 4.0.

Notes: Capacity additions refer to net additions. Comparison periods are the forecasts for 2023 to 2027. Solar PV and wind additions include capacity dedicated to hydrogen production.

The wind forecast is less optimistic outside of China

Overall, the wind industry is facing financial challenges the world over (see the Financial Health section), with most large Western manufacturers having reported losses over the past two years. As overall project development outside of China has been slower than expected for most countries analysed, we have revised the onshore wind forecast downwards.

Outside of China, onshore wind additions are not advancing considerably in other large markets such as India, and the forecast has been revised down for the ASEAN region, Africa and the Middle East due to slow project progress and ongoing policy uncertainties. In the European Union, long permitting wait times, supply chain challenges and higher equipment and financial costs also reduce anticipated onshore wind deployment. However, costs for offshore wind development have risen the most, causing us to revise this year's forecast down by 16% outside of China.

The offshore industry is facing headwinds

Following the capacity growth resulting from favourable policies and declining costs over the last decade, the cost of materials used to make offshore wind

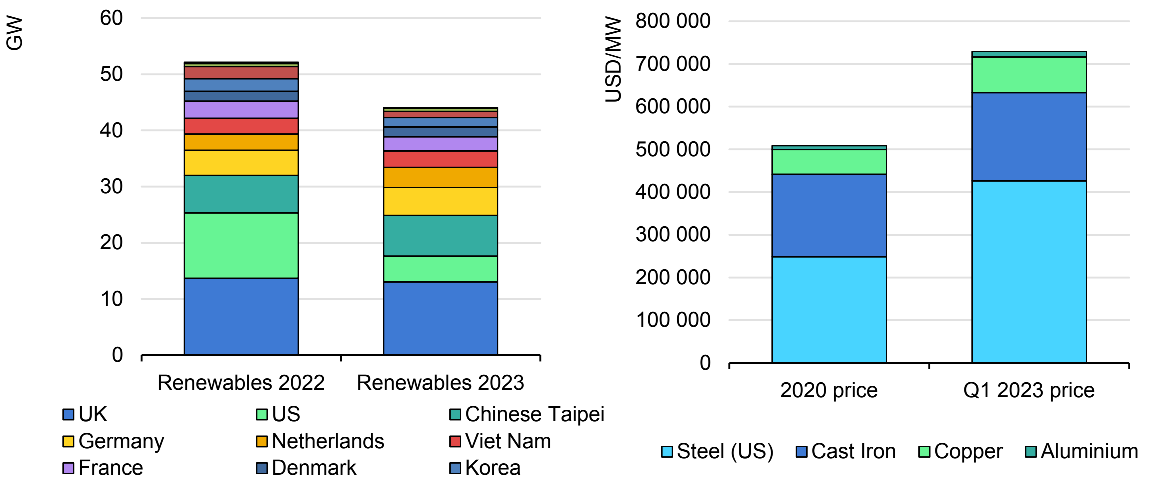
IEA. CC BY 4.0.

components has been rising since early 2020 due to supply chain constraints and inflation, leading to a more than 20% increase in offshore wind investment costs. In addition, higher financing costs are putting additional pressure on developers that signed power purchase agreements under low equipment and borrowing costs before the global energy crisis hit.

Two of the largest countries for offshore wind additions outside of China – the United States and the United Kingdom – are being acutely impacted by the changing economic conditions. In the United States, over 10 GW of capacity previously awarded in state tenders have been delayed or are at risk of being delayed or cancelled, resulting in a downward revision of more than 60% to our US offshore wind forecast. Project economics are the main factor, with developers trying to renegotiate their contract prices because bids were awarded in an economic context of low interest, inflation and commodity price rates.

Some developers who cancelled awarded projects are planning to bid for the capacity again in future auctions, presumably at a higher price. Indeed, the state of New York plans to hold new tenders to replace cancelled projects, with prices indexed to inflation. Auction and tender participation have also been impacted, with the latest tender in Rhode Island attracting only one bid, while a federal lease auction in the Gulf of Mexico also resulted in only one bid, with two lease areas receiving no bids at all.

Offshore wind capacity forecast revisions excluding China, and wind component commodity price increases



IEA. CC BY 4.0.

Rising offshore wind development costs have also affected the United Kingdom in two ways. The first is low auction participation, with the most recent renewable energy auction attracting no bids for the 4 GW of offshore wind capacity available because the maximum bid price of GBP 44/MWh (in 2022 GBP) was not high enough to cover the cost of building new capacity (GBP 53/MWh).

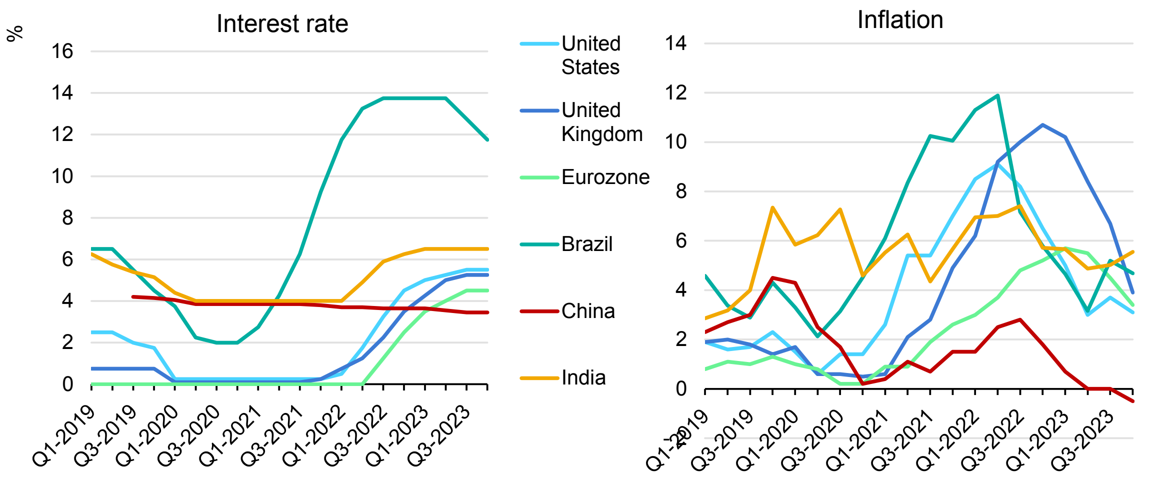
IEA. CC BY 4.0.

The second is project cancellation, with higher costs making it uneconomic to build previously awarded capacity: for instance, Vattenfall cancelled the Norfork Boreas 1.4-GW offshore wind project because costs have risen 40%. While prices awarded in UK contract-for-difference (CfD) auctions do not adjust for rising inflation between contract awarding and project commissioning, the maximum price for auctions announced in November 2023 was increased 66% (from GBP 44/MWh to GBP 73/MWh).

The new macroeconomic environment presents additional renewable energy challenges

Exponential renewable electricity expansion, along with strong policy support, has reduced wind and solar PV generation costs by more than 80% since 2010. However, a significant majority of this growth in advanced economies took place during the quantitative easing period when central bank base interest rates (excluding project and company risk premiums) were below 1% in the European Union, the United Kingdom and the United States. In emerging economies, interest rates were considerably higher during the same period, but this was partially counterbalanced by much lower investment costs, especially in China and India. The availability of low-cost financing supported by governments and international financial institutions, also boosted growth.

Quarterly interest rates and inflation in selected countries, 2019-2023



IEA. CC BY 4.0.

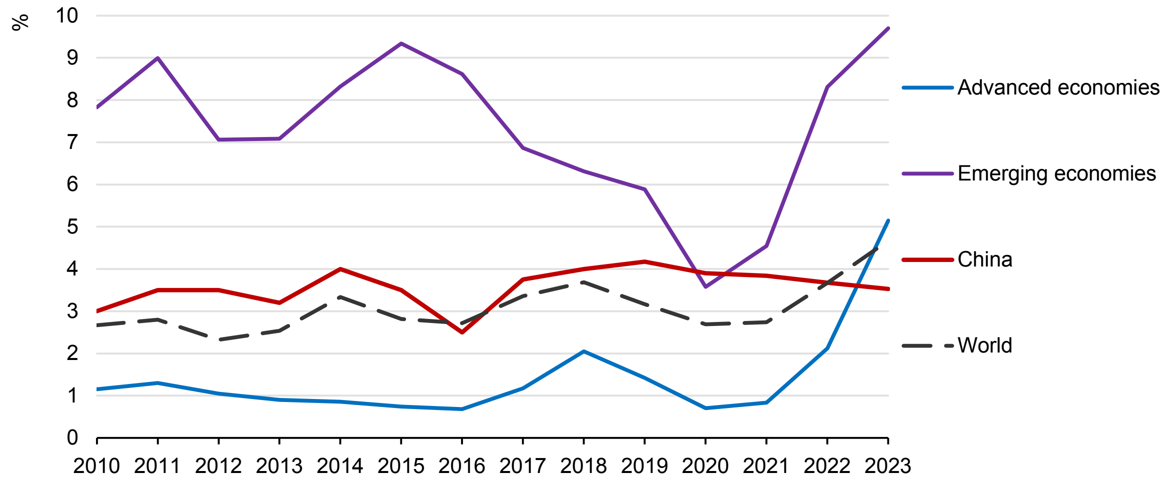
Source: Bloomberg LP.

Since 2022, central bank base interest rates have increased from below 1% to almost 5%, and annual inflation has reached around 10% in many advanced economies in mid-2022. In 2023, new renewable energy capacity financed in advanced economies was exposed to higher base interest rates than in China and

IEA. CC BY 4.0.

global average for the first time, mainly because the Chinese government decided to cut interest rates rather than follow the global trend. In emerging markets and developing economies (EMDEs), renewable developers have always exposed to higher interested rates, resulting in higher costs hampering faster expansion of renewable capacity. The lack of affordable financing remains the most important challenge to renewable project development in most EMDEs, especially in countries where renewable policy uncertainties also increase project risk premiums.

Average central bank base interest rates weighted by renewable energy deployment, 2010-2023



IEA. CC BY 4.0.

Notes: Weighted averages are based on renewable capacity deployed for each country/region. Countries with limited information on official interest rates are excluded from this analysis.

The implications of this new macroeconomic environment are multi-fold. First, inflation has raised equipment costs for onshore and offshore wind and, partly, for solar PV (excluding module costs[1]). Second, higher interest rates are increasing the financing costs of capital-intensive variable renewable technologies. Third, delayed policy responses (because governments have been expecting the past decade's cost reductions to continue) and permitting challenges have left several auctions in advanced economies, especially in Europe, undersubscribed. Additionally, developers whose power purchase contracts were signed prior to these macroeconomic changes have had to cancel their projects. Government policies to improve auction design and contract indexation methodologies would help resolve these new challenges to unlock additional wind and solar PV capacity deployment.

[1] Module costs have not declined worldwide. Countries with trade measures against Chinese cells and modules are not experiencing price reductions.

IEA. CC BY 4.0.

Rapid government responses to grid connection, permitting, policy and financing challenges can accelerate renewable energy growth

In the main case, taking country-specific challenges that hamper faster renewable energy expansion into account, we forecast that almost 3 700 GW of new renewable capacity will become operational worldwide over the next five years. In contrast, in our accelerated case, we assume that governments overcome these challenges and implement existing policies more quickly.

These challenges fall into four main categories. First are policy uncertainties and delayed policy responses to the new macroeconomic environment, encompassing inflexible auction design. During the energy crisis, governments intervened in energy markets to protect consumers from high prices. While these interventions were justified, they also created uncertainty for investors over the future investment environment in the electricity sector. The macroeconomic changes also drove up costs and contract prices for wind and solar PV projects, and a lack of reference price adjustments and contract price indexation methodologies reduced the bankability of projects, mostly in advanced economies.

Meanwhile, emerging economies have been slow to develop strong renewable energy targets and clear incentive schemes. While renewable energy projects (especially solar PV and wind) are already more affordable than fossil fuel-based alternatives, slower-than-expected demand growth has resulted in overcapacity of young coal and gas fleets in many emerging economies, creating little need for additional capacity.

The second problem is insufficient investment in grid infrastructure, which has been preventing faster expansion. Today, more than 3 000 GW of renewable generation capacity are in grid queues, and half of these projects are in advanced stages of development.[2] This challenge holds true for both advanced economies and emerging and developing countries. Development lead times for grid infrastructure improvements are significantly longer than for wind and solar PV projects.

The third challenge involves permitting. The amount of time required to obtain permits can range from one to five years for ground-mounted solar PV projects, two to nine years for onshore wind, and nine years on average for offshore wind projects. Delays resulting from complex and lengthy authorisation procedures are slowing project pipeline growth, limiting participation in renewable energy

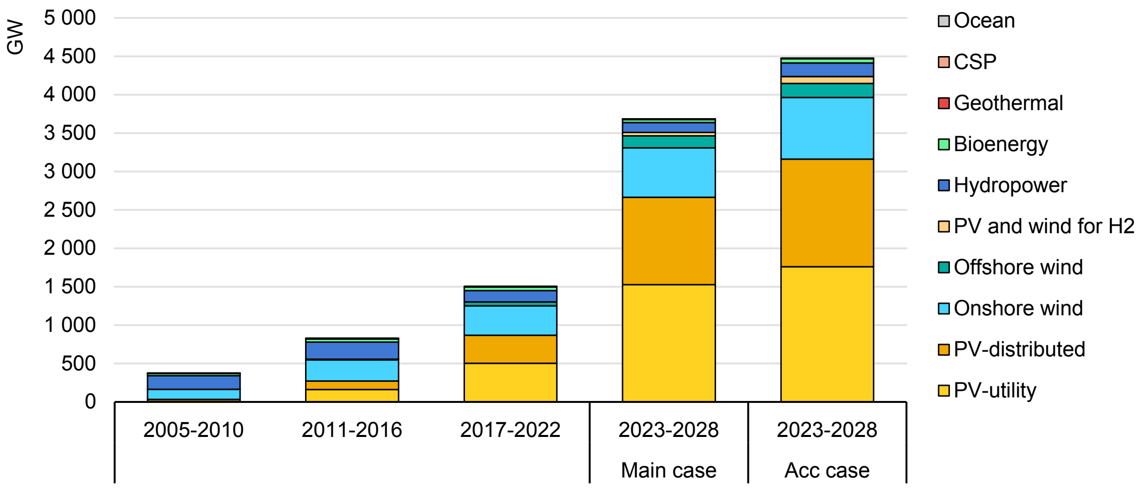
[2] Connection queue data based on publicly available information from the United States, Brazil, Colombia, Spain, France, Italy, the United Kingdom, India, Japan, Chile, Germany, Australia and Mexico.

IEA. CC BY 4.0.

auctions, raising project risks and costs, and ultimately weakening project economics.

The fourth obstacle is insufficient financing in developing countries. Mitigating risks in high-risk countries through concessional financing continues to be challenging because of ongoing policy uncertainties and implementation challenges, for instance in Kenya, South Africa, and Nigeria. In many developing countries, government-owned utilities are under financial stress and the weighted average cost of capital (WACC) can be two to three times higher than in mature renewable energy markets, reducing project bankability. Every percentage point decline in the WACC reduces wind and solar PV generation costs by at least 8%.

Renewable capacity growth by technology, 2005-2028



IEA. CC BY 4.0.

Notes: CSP = concentrated solar power. Capacity additions refer to net additions.

Governments have multiple options to address these challenges in the short term to unlock 21% more renewable capacity in the accelerated case, with almost 4 500 GW becoming operational in the next five years. In our accelerated case forecast, governments can achieve important policy improvements by:

- Simplifying permitting procedures and/or setting clear permitting timelines; identifying preferential areas for renewable energy projects to fast-track permitting; and removing certain permitting requirements for small renewable power projects or increasing the minimum capacity requirement for environmental impact assessments without compromising strong sustainability measures.
- Considering that new grid infrastructure often takes 5-15 years to plan, compared with 1-5 years for new renewable energy projects; aligning and integrating planning and execution of transmission and distribution grid projects with broad long-term energy planning processes, and ensuring that regulatory risk assessments allow for anticipatory investments.

IEA. CC BY 4.0.

- Standardising power purchase contracts and backing them up with government guarantees, especially for publicly owned utilities, to reduce financial risks for off-takers.
- Adapting auction designs to the new macroeconomic environment by indexing contract prices to various macroeconomic indicators specific to each renewable technology, such as relevant commodity prices, inflation and interest rates for different stages of project development.
- Implementing policies and regulatory reforms to de-risk renewable energy investments and reducing the cost of financing, especially in EMDEs.

In our accelerated case, onshore wind and utility-scale solar PV together have the largest upside potential. Simplifying permitting and adapting auction designs would lead to higher auction subscriptions, and thus faster deployment of utility-scale solar PV and wind power plants, as would higher investment in transmission and distribution grids.

For distributed solar PV, although we have already revised our forecast upwards to reflect policy improvements and higher retail prices for electricity, the pace of consumer adoption is always a forecast uncertainty, especially in a high-interest-rate environment. Our accelerated case therefore assumes faster adoption of residential and commercial solar PV thanks to the prolongation of high retail electricity prices and government support for low-cost financing.

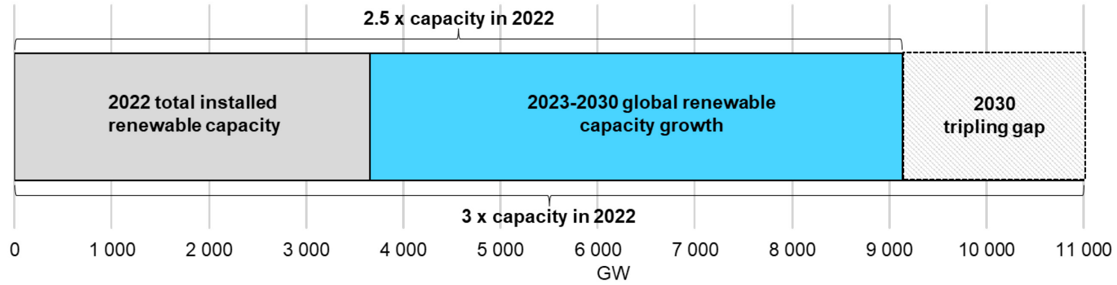
Net Zero Emissions by 2050 Scenario tracking

The tripling goal is within reach, but more effort is needed

Prior to the COP28 climate change conference in Dubai, the International Energy Agency (IEA) urged governments to support five pillars for action by 2030, among them the goal of tripling global renewable power capacity. Several of the IEA priorities were reflected in the Global Stocktake text agreed by the 198 governments at COP28, including the tripling renewables goal. Tripling global renewable capacity from 2022 levels by 2030 would take it to 11 000 GW, in line with the IEA Net Zero Emissions by 2050 Scenario. Under existing policies and market conditions, global renewable capacity is forecast to reach 7 300 GW by 2028 in our main case. Although this growth means that renewables account for almost all newly added power capacity worldwide, its trajectory would see global capacity increase to 2.5 times its current level by 2030, falling short of the tripling goal. In our accelerated case forecast, global cumulative capacity more than doubles to reach over 8 130 GW by 2028, putting the world nearly on track to meet the global tripling pledge.

IEA. CC BY 4.0.

Renewable capacity growth from 2022 to 2030 and the gap to global tripling renewables goal



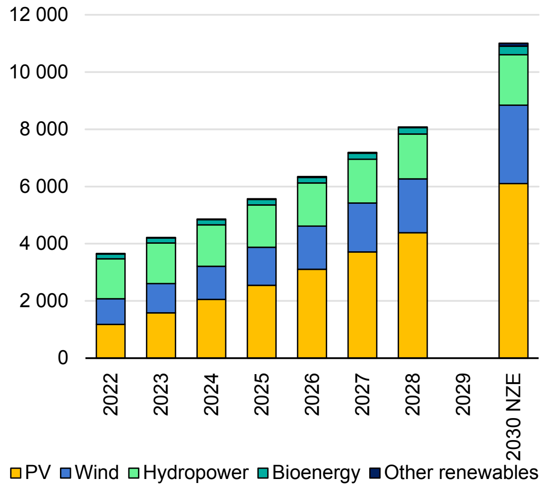
IEA. CC BY 4.0.

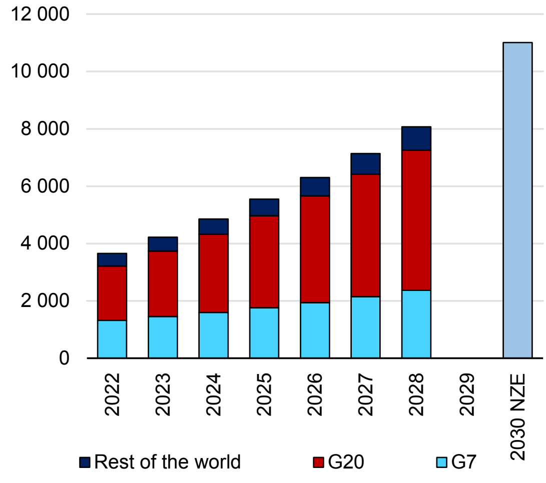
In 2023, G20 countries collectively accounted for almost 90% of global cumulative renewable power capacity. In September 2023, G20 leaders declared their willingness to "…pursue and encourage efforts to triple renewable energy capacity globally through existing targets and policies, […], in line with national circumstances by 2030". Accordingly, they have the potential to significantly contribute to a global tripling of renewables, through full and faster implementation of existing policies and targets. However, stronger policy efforts are needed in many other countries. Renewable energy expansion in 2023 was heavily concentrated in just ten countries, responsible for 80% of global annual additions. To achieve a tripling of global renewable capacity, a much faster deployment rate is necessary in numerous other nations. Moreover, many emerging and developing economies rely primarily on hydropower. This implies that solar PV and wind must grow significantly more than threefold by 2030 to meet the global tripling goal. Achieving this will demand new policies tailored to the unique circumstances and requirements of emerging and developing nations.

Relative to our accelerated case projections for renewable capacity in 2028, reaching the tripling of renewables by 2030 would necessitate the commissioning of almost 3 000 GW of new renewable capacity in 2029 and 2030. Average annual renewable capacity additions in 2029-2030 would therefore have to be 165% higher than in 2027-2028, the last two years of our accelerated case forecast.

IEA. CC BY 4.0.

Cumulative renewable electricity capacity in the accelerated case (2022-2028) and Net Zero Scenario (2030)





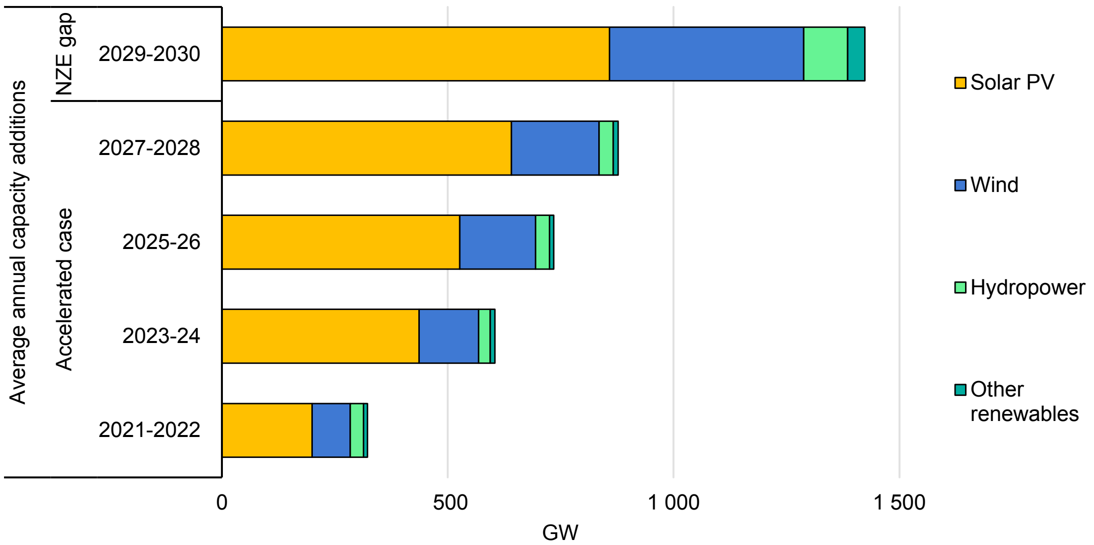
IEA. CC BY 4.0.

Note: NZE = IEA Net Zero Emissions by 2050 Scenario. G7 and G20 aggregates include all EU countries. Solar PV and wind include capacity dedicated to hydrogen production.

Source: For the Net Zero Scenario, IEA (2023), World Energy Outlook 2023.

Gaps also vary significantly by technology. For solar PV, additions need to increase just 35% in 2029 and 2030 while for wind they would need to double. For hydropower and other renewables, annual additions need to triple compared with 2027 and 2028.

Average annual renewable electricity capacity additions and gap to IEA NZE Scenario



IEA. CC BY 4.0.

Notes: NZE = IEA Net Zero Emissions by 2050 Scenario. Capacity additions refer to net additions. Solar PV and wind additions include capacity dedicated to hydrogen production.

Source: IEA (2023), World Energy Outlook 2023.

IEA. CC BY 4.0.

Regional forecast trends

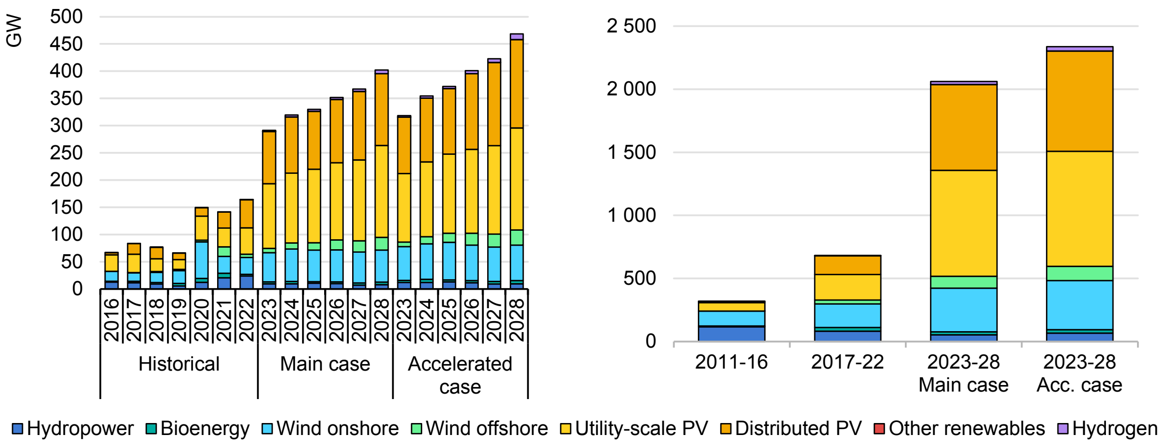
China

Increasing solar PV and wind competitiveness spurs a step change in renewable energy growth

China's renewable energy capacity is expected to expand by over 2 TW over 2023-2028, tripling growth of the last five-year period, with solar PV making up three-quarters of the increase. Owing to new investments since mid-2022, China's solar PV manufacturing capacity now strongly exceeds both local and global demand, which has driven module prices down significantly and made solar installations more competitive with regulated power prices.

With the phaseout of central-government subsidies, wind and PV developers are signing 15- to 20-year power purchase contracts at administratively set provincial benchmark electricity prices, mostly defined by coal generation. Today, generation costs for new utility-scale solar PV and onshore wind systems are lower than for coal in almost all provinces, creating a more optimistic outlook as they help provinces achieve lower electricity prices. Our forecast expects that China will reach its 1 200 GW of cumulative solar PV and wind capacity target by 2030 this year.

China renewable capacity additions by technology, main and accelerated cases, 2011-2028



IEA. CC BY 4.0.

Note: Hydrogen refers to renewable capacity dedicated to hydrogen production. Other renewables refers geothermal and CSP.

With several policy and market trends doubling China's renewable capacity expansion in the next five years, we have revised its renewable energy forecast up 64% from last year. First, solar PV module costs have plummeted drastically

IEA. CC BY 4.0.

because of the growing supply glut while interest rates have been in decline since January 2023, making solar PV power more competitive with coal-fired generation.

Second, recent power market reforms and green certificate systems have allowed some utility-scale solar PV and wind developers to tap into better prices than under regulated contracts. Electricity prices are higher in several provinces where more power is traded in local wholesale markets. In addition, the energy regulator has clarified its rules for green energy certificates, for which demand is increasing, and developers in resource-rich areas can gain additional revenues by selling green power to other provinces.

Third, provincial financial support for small-scale residential solar PV systems and rising retail prices this year in the industry sector have been stimulating faster commercial and industrial deployment.

However, China's rapid solar PV and onshore wind growth is expected to present grid integration challenges for new utility-scale and distributed PV projects and impact project economics in the medium term. In North and Northeast provinces, curtailment is expected to increase and reduce project bankability, especially given the large number of plants being deployed in these grid areas.

In our accelerated case, quicker implementation of power market reforms and interprovincial green energy certificate trading could alleviate system integration issues and unlock additional capacity of 13%. Overall, though, the upside potential of the accelerated case compared with the main case is rather limited because China's current growth trajectory indicates it will overachieve on most of its announced renewable energy targets.

United States

While the Inflation Reduction Act spurs solar PV-led growth, the offshore wind forecast is revised down

The United States is forecast to add nearly 340 GW of renewable energy capacity over 2023-2028, almost all in solar PV and wind installations. While supply chain issues and trade concerns still linger in the market in the near term, the Inflation Reduction Act (IRA) has accelerated the pace of additions from last year's forecast. Growth is stronger especially for the later years of the forecast period, as final credit guidance from the Internal Revenue Service doubles annual investments in renewable electricity from five years ago. Nevertheless, the offshore wind forecast has been revised down by more than 60% because project developers are cancelling or delaying planned or contracted capacity due to current macroeconomic conditions.

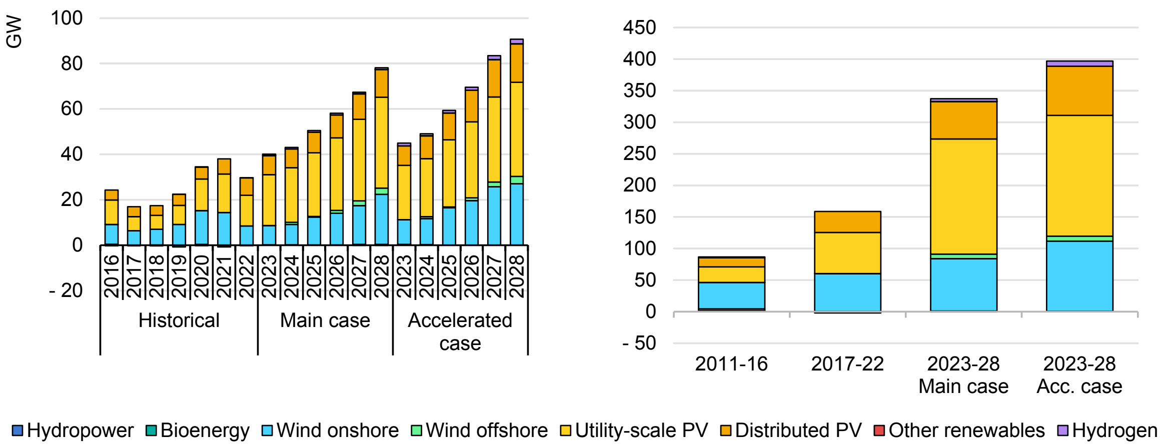
IEA. CC BY 4.0.

For utility-scale solar PV and onshore wind, growth is driven by the IRA's clean energy tax credits available for both technologies beginning in 2024. Projects can qualify for either the investment or the production tax credit, with additional credits for domestic content; for siting a project in an energy community, a low-income community or a qualifying low-income residential building project of economic benefit; and for paying prevailing wages and using registered apprentices. Solar PV leads additions, with utility-scale capacity increasing steadily throughout the forecast period, though a contraction in residential growth is expected in 2024 due to net-metering rule changes in California, the country's largest residential market.

Distributed solar PV growth is encouraged by the federal tax investment credit, along with state- and utility-level incentives for net metering. Meanwhile, onshore wind additions remain relatively stable in the first half of the forecast period as projects that qualified for previous incentives come online. Additions accelerate in the second half, however, as the credit certainty provided by the IRA boosts development.

Offshore wind growth is enabled by federal lease auctions and state-level tenders. While the first major offshore wind project in the United States began delivering power to the grid in 2023, additional projects that already received federal approval create higher additions in the second half of the forecast period.

United States renewable capacity additions by technology, main and accelerated cases, 2011-2028



IEA. CC BY 4.0.

Note: Hydrogen refers to renewable capacity dedicated to hydrogen production. Other renewables includes geothermal and CSP. Negative net additions refer to retirements.

While the IRA provides long-term incentives for growth, some market challenges persist. First are supply chain constraints, which have led to project delays for both wind and solar PV. While logistical and pricing challenges have eased, the compounding effects of previous delays are still being felt, especially in the short term.

IEA. CC BY 4.0.

Second, grid constraints and connection queue backlogs are a growing concern. The Federal Energy Regulatory Committee has therefore issued new rules to reduce connection queues, and some regional TSOs have reconfigured their project assessment policy to meet rising demand.

Two additional challenges for solar PV are the potential for modules to be delayed at ports while customs officials verify compliance with trade regulations, and consumer hesitancy to install distributed PV due to inflation and rising interest rates. A similar challenge exists for offshore wind, with multiple projects being cancelled, delayed or requesting contract price renegotiations because rising costs and interest rates have changed the project economics.

In the accelerated case, addressing these concerns or mitigating their effects results in over 17% higher growth than in the main case.

Asia Pacific

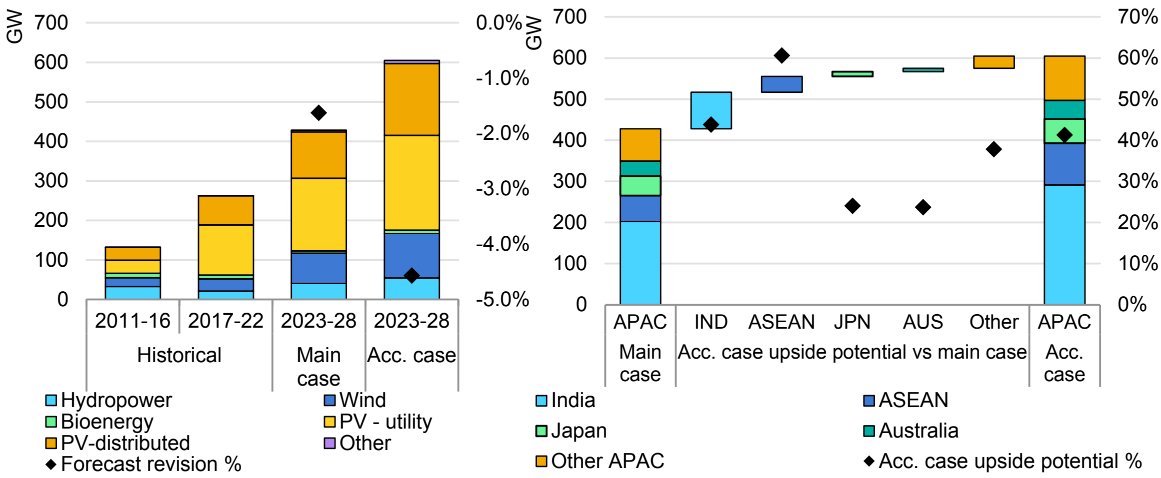
Renewable capacity is expected to increase by almost 430 GW over 2023-2028 – 73% growth from 2022. Solar PV makes up over two-thirds of the expansion, mostly from utility-scale applications. India will account for half of the region's growth, with the Association of Southeast Asian Nations (ASEAN) contributing 14% and Japan 11%. By 2028, annual Asia-Pacific renewable energy capacity growth is expected to almost double from the 2022 level, but its contribution to global expansion remains the same. Overall, our forecast is mostly unchanged from last year, as downward revisions for Korea and Australia are offset by a more positive outlook for India and Japan.

India is forecast to add 205 GW over 2023-2028, doubling 2022's cumulative installed capacity, making it the world's third-largest market for renewables. The announcement of higher auction volumes, the introduction of a closed-envelope bidding process for wind, improvements in grid-access rules for commercial distributed PV, the settlement of majority of overdue payments to the generators led to 3% upward forecast revision. Undertaken actions are expected to help India advance towards its goal of installing 500 GW of non-fossil-based capacity by 2030.

In **Japan**, renewable energy deployment is fuelled primarily by projects awarded under the previous feed-in-tariff scheme and the newly introduced feed-in-premium (FIP) mechanism. Oversubscription in the first FIP auction in 2022, coupled with faster-than-expected growth of the corporate PPA market, has resulted in a forecast revision of close to 15%.

IEA. CC BY 4.0.

Asia Pacific renewable capacity additions, 2011-2028



IEA. CC BY 4.0.

Notes: Other includes geothermal and renewable capacity dedicated to hydrogen. APAC = Asia Pacific. IND = India. ASEAN = Association of Southeast Asian Nations. JPN = Japan. AUS = Australia.

Conversely, we are revising **Korea**'s forecast down by over 40% and **Australia**'s down by over 10%. In **Korea**, this revision results mainly from the government's decision to lower the renewable energy target for 2030 from 30% to 22%. This shift reflects a strategic decision to enlarge the role of nuclear power in the country's energy transition. In addition, auctions, which are the primary mechanism to support renewable energy growth, continued to be significantly undersubscribed in 2023.

In **Australia**, rising investments cost and slow progress in project development for renewable-based hydrogen and hydropower (Snowy 2.0) projects has led to a downward revision of utility-scale projects. Notably, the distributed PV segment, which has been the primary source of growth in Australia in recent years, is forecast to experience a faster-than-anticipated decline in installations due to saturation of the power system and increasing grid integration challenges. However, rooftop PV uptake in Australia has shown remarkable resilience in recent years despite state-based feed-in-tariffs tapering off, and saturation of the power system. This has been driven by local energy security and decarbonisation goals.

For the ASEAN region, our forecast is mostly unchanged from last year. In **Indonesia**, the government issued a decree in 2022 to establish a policy framework for a new auction-based renewable energy support system. However, the detailed regulations necessary for procurement and project development were still pending as of October 2023, which has delayed the expected positive impact of the new policy.

In **Viet Nam**, the much-anticipated new National Electricity Development Plan, which includes renewable capacity targets for 2030, has been adopted. The plan assumes significant deployment of wind capacity; however, the government has not addressed a gap in policy support present since 2021, which is impeding project development.

IEA. CC BY 4.0.

Meanwhile, **the Philippines** introduced an auction programme in 2022 that is expected to significantly boost utility-scale PV and onshore wind growth. Although the government has announced ambitious auction volume targets, rapid deployment is being hampered by delays in developing the transmission system.

In **Thailand**, the continued absence of substantial policy support has limited the pace of renewable energy growth, with only modest additions expected for the distributed PV segment.

In the accelerated case, Asia-Pacific renewable energy growth in 2023-2028 could surpass main case projections by more than 40%, which is nearly double the global average. The **ASEAN** region and **India** have the greatest potential for acceleration. For **India**, its already-dynamic development could jump almost 45% if policymakers address the poor financial performance of utility companies (DISCOMs) and sluggish distributed PV deployment, and facilitate wind project development.

Upside potential for the **ASEAN** region is even more significant, close to 60% and giving it one of the highest growth possibilities globally. However, realising this potential will require more ambitious renewable energy targets and the swift implementation of long-term, transparent and competitive support policies.

In the developed countries of the Asia Pacific region, i.e. **Japan**, **Korea** and **Australia**, overcoming grid bottlenecks, streamlining lengthy permitting processes and enhancing system flexibility should be prioritised to accelerate deployment.

Fossil fuel-based overcapacity is a significant impediment to ASEAN renewable energy deployment, while system integration challenges remain limited

Existing coal- and gas-fired power plant overcapacity in some ASEAN countries, including Indonesia, the Philippines, Thailand and Malaysia, remains a major obstacle to faster renewable energy deployment. Over the last decade, many countries in the region overinvested in conventional generation assets, mainly coal-fired, based on optimistic power demand projections and conservative safety margins for installed capacity. As a result, today reserve margins (excess of dispatchable capacity over peak demand) in the region often exceed 50% and reach over 90% in Indonesia.

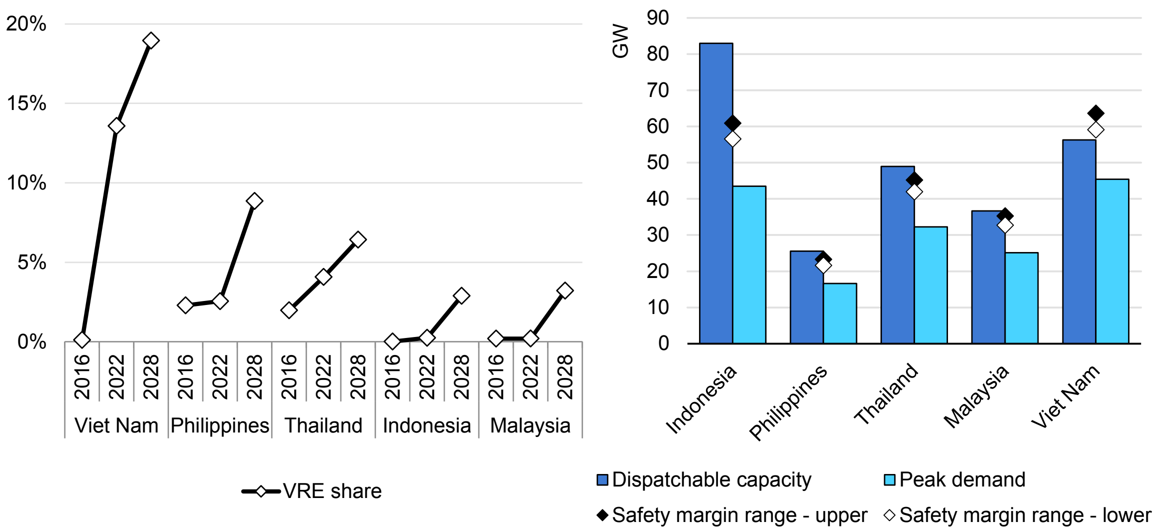
The region also has a very young fossil fuel-fired fleet capable of meeting electricity demand even in 2028, with more under development. Many of these assets have entered fixed or take-or-pay contracts with utility companies to secure financing. Utilities bound by legacy supply contracts for the next 10-15 years have little financial incentive to contract new renewable power, as they are obligated to compensate fossil fuel plant operators for any displaced generation. This would

IEA. CC BY 4.0.

create additional financial stress for multiple utilities in the region. Viet Nam remains an exception, having dynamic demand growth that allows the public utility to procure power from all sources, with cost being the primary criterion.

Finding solutions to this complex issue requires a multidimensional approach aiming a coordinated and orderly transition. It is necessary to accelerate renewable energy growth to achieve climate goals while at the same time acknowledging the limited procurement capabilities of utility companies and alleviating the risk of many new fossil fuel plants becoming stranded assets.

Share of VRE generation in the main case forecast, 2016-2028 (left), installed dispatchable capacity and peak power demand, 2022 (right)



IEA. CC BY 4.0.

Notes: VRE = variable renewable energy.

Government intervention is thus required to introduce more flexibility into existing fixed contracts and enable lower annual capacity factors for fossil fuel-fired power plants, while ensuring that generators receive fair returns on their investments. Governments should also re-evaluate the need for new conventional plants and explore options for early retirement of the oldest assets through agreements with plant operators. Furthermore, the use of international financial support, through initiatives such as the Just Energy Transition Programme, could be considered to reduce financial pressure on government budgets. Viet Nam and Indonesia are already taking advantage of this opportunity, having signed their JETP agreements in 2023.

Considering the relatively low penetration of wind and solar PV systems in many ASEAN economies, the upside potential in our accelerated case compared with the main case is one of the largest of all regions. Until 2028, variable renewable energy (VRE) generation in the Philippines, Thailand, Indonesia and Malaysia is

IEA. CC BY 4.0.

expected to remain below 10% – in integration phase 2 in most cases, according to IEA categorisation (see the section on VRE shares later in this chapter for an explanation of system integration phases). In other words, adjusting power system operations to accommodate additional VRE capacity is expected to require relatively straightforward flexibility measures and limited investments.

Existing dispatchable assets, primarily fossil fuel and hydropower plants, should provide the flexibility necessary to accommodate PV and wind capacity, even in the accelerated case. Nevertheless, to take advantage of this affordable and relatively easy-to-integrate variable renewable energy, government support will be required to address the challenges of conventional power plant overcapacity and inflexible legacy contracts.

Viet Nam remains an exception in this regard because the country is already experiencing system integration challenges following the solar PV boom in which installations reached 20 GW in 2019 and 2020. This rapid expansion of solar PV in such a short time in concentrated areas resulted in generation curtailment and the need to enlarge investments in transmission and distribution infrastructure quickly.

Europe

The pace of renewable capacity growth in Europe will more than double in 2023-2028 compared with the previous six years, with additions totalling 532 GW. Solar PV accounts for over 70% of the expansion, led by distributed systems, which is one-third more than utility-scale. Wind accounts for another 26% led by onshore projects.

The main drivers for utility-scale growth are: 1) supportive policies, in the form of government auctions to achieve long-term renewable energy targets; and 2) attractive market conditions for unsubsidised projects through bilateral contracts between IPPs and corporate consumers or utilities, in some cases supported by revenues from the wholesale market. Owing to high retail electricity prices and policies that remunerate excess generation, the business case for self-consumption is a major attraction for distributed solar PV uptake.

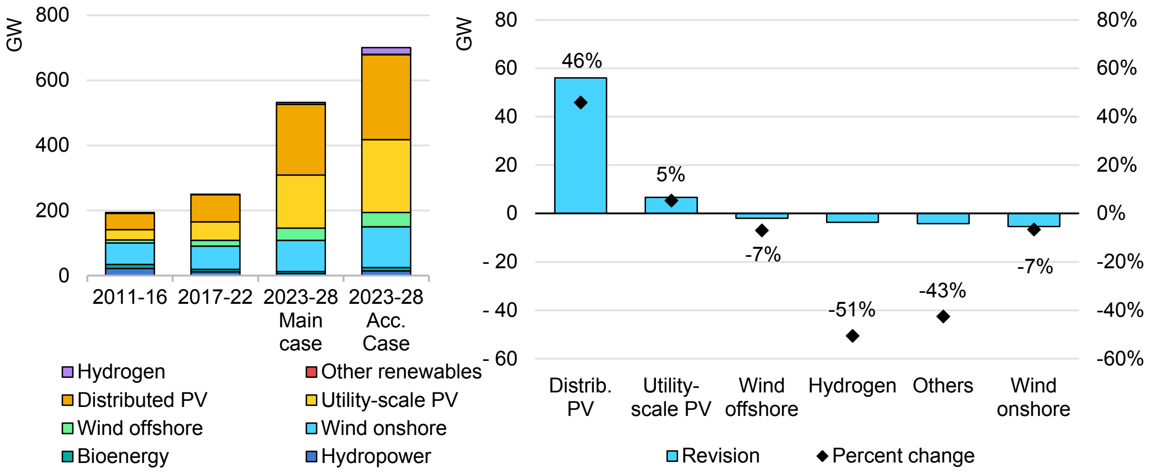
While we have revised the forecast for Europe up by 12% from last year, this reflects solely a more optimistic outlook for solar PV. Distributed solar PV continues to be the main source of expansion, and the main reason for the upward revision because high electricity prices and better policy support are making self-consumption more economically attractive. Sixty percent of the additional distributed PV capacity revision comes from Germany, Italy, Spain, Sweden, the United Kingdom, France, the Netherlands, and Belgium, where governments have introduced new feed-in tariffs and tax exemptions and extended existing support schemes in 2022 to accelerate distributed PV uptake. This resulted in record-

IEA. CC BY 4.0.

breaking growth in 2022 and in some markets, higher than expected growth in 2023, prompting our upward forecast revision.

Since the *Renewables 2022* forecast, other European countries' outlooks have also been revised upwards as they continued to implement new policies in 2023. For instance, Finland mandated net metering for all DSOs starting in January while Ireland increased its size eligibility from 6 kW to 1 MW. In the first five months of 2023, Switzerland, Slovenia and Bulgaria introduced rebate schemes, while funding for existing rebate schemes was increased in Czechia and Romania. Romania also reduced its VAT for PV systems from 19% to 5% in January, while Ireland slashed it to 0% in April and Austria followed suit in October.

Europe renewable capacity additions by technology, main and accelerated cases, 2011-2028 (left) and forecast revisions (right)



IEA. CC BY 4.0.

Note: Hydrogen refers to renewable capacity dedicated to hydrogen production. Other renewables refers geothermal and CSP.

Utility-scale solar PV growth is also being revised up by 5% owing to improvements in auction schemes to account for rising developer costs in the first half of 2023 in Germany, where price ceilings were increased, and in France, where contracts were indexed to inflation-related costs during construction. Faster corporate PPA growth in Denmark also supports the upwards revision.

These increases overshadow downward revisions for other markets, stemming from poor auction performance. For instance, less capacity was awarded than expected in the November 2023 auction in Spain because most of proposed bids exceeded the ceiling prices, in the Netherlands because of more competitive low-carbon technologies, and in Poland as a result of land constraints and permitting challenges.

IEA. CC BY 4.0.

Contrary to solar PV, this year's forecast is less optimistic about the growth of wind and renewable capacity for hydrogen production compared with *Renewables 2022*. Onshore wind has the largest downward revision, 5.4 GW lower growth (-7%) than in the previous forecast because deployment in some markets was more sluggish than expected in 2022 (permitting and grid constraints led to undersubscribed auctions and lengthy project development times).

Also in 2022, Spain, Italy and Greece awarded less capacity than they offered due to developers' inability to obtain permits and/or more attractive business cases through other routes to market such as corporate PPAs or merchant tails. Uncertainty over the introduction of new support in the Republic of Türkiye (hereafter "Türkiye") and extension of the SDE++ programme in the Netherlands after 2022 have also led to lulls in the project pipeline.

However, these downward revisions overshadow other European markets where there have been positive market and policy developments. Growth in Germany and France is expected to be stable thanks to prompt policy action that resulted in more capacity being awarded in 2023 than previously expected. In Germany, the government introduced reforms in 2022 to streamline permitting and raised the ceiling prices in 2023 to account for higher investment costs. As a result, a record 1.9 GW of onshore wind was awarded in December 2023, the highest since auctions began in 2017. France also updated contract indexation to provide developers a better hedge against inflation, as well as clarified auction specifications in 2023. As a result, 2 GW of onshore wind was awarded in the last two auction rounds, six time the volume awarded in the previous two rounds. In addition, he forecast for onshore wind uptake in Sweden is higher owing to increased corporate PPA activity.

The forecast for offshore wind has been revised down 7% because of persistently long lead times and concerns over the economic attractiveness of future projects. Postponements are expected for projects in Belgium and France after announced commissioning dates were pushed back; in Poland due to funding delays for port infrastructure; and in Sweden owing to a permitting denial. In the United Kingdom, fewer projects are expected to be developed because developers are not finding them bankable. No offshore wind capacity was awarded in the October 2023 auction because the ceilings were too low, while another developer has halted a project due to rising costs.

For hydrogen, financial closure for electrolyser projects in Sweden, the Netherlands, Spain and Germany are progressing more slowly than expected, causing the forecast for renewable capacity dedicated to hydrogen production to be revised down by over 50%.

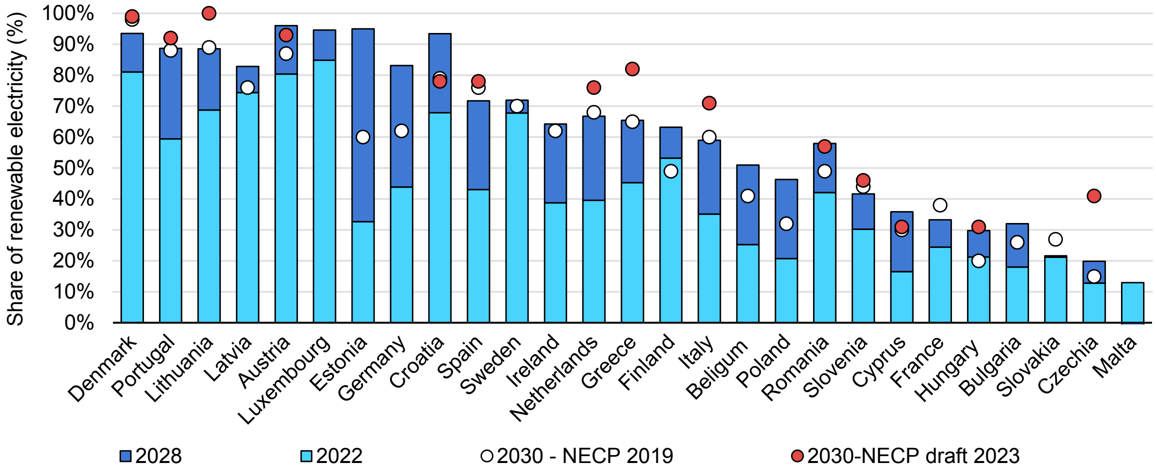
Despite these downward revisions, in the main case the share of renewable electricity generation in Europe increases from 41% in 2022 to 61% in 2028.

IEA. CC BY 4.0.

However, it is uncertain for two reasons whether this pace will be fast enough to meet 2030 ambitions. The first is that for EU countries, 2030 targets are in a state of transition. In July 2023, the European Union formally decided to increase the share of renewable energy in final energy consumption from 32% to 42.5% by 2030 to accelerate decarbonisation and reinforce energy security.

As a result, member states are now in the process of redesigning their National Energy and Climate Plans (NECPs), wherein they assess their contribution to the new EU target and set new individual goals when necessary. At the time of writing, only 21 of the 27 countries had submitted drafts, of which only 14 explicitly set renewable electricity targets. Final targets for all countries will likely be known only after the review process ends in June 2024.

European Union renewable energy share in electricity generation by country, 2022 and 2028, and NECP targets (2019 and 2023 draft)



IEA. CC BY 4.0.

Notes: NECP = National Energy and Climate Plan. Data for Luxembourg and Malta are unavailable.

Note by Türkiye: The information in this document with reference to « Cyprus » relates to the southern part of the Island. There is no single authority representing both Turkish and Greek Cypriot people on the Island. Türkiye recognises the Turkish Republic of Northern Cyprus (TRNC). Until a lasting and equitable solution is found within the context of the United Nations, Türkiye shall preserve its position concerning the "Cyprus issue".

Note by all the European Union member states of the OECD and the European Union: The Republic of Cyprus is recognised by all members of the United Nations with the exception of Türkiye. The information in this document relates to the area under the effective control of the e Government of Government of the Republic of Cyprus.

Sources: IEA analysis based on NECP data from EMBER (2023), Live EU NECP Tracker.

The second source of uncertainty is the persistent obstacles that countries face to accelerate renewable energy deployment: slow and complex permitting procedures; grid congestion; and inadequate policy support in today's economic climate. The extent to which these obstacles affect each country varies: for some, the impact is sizable enough that they risk not meeting their original 2030 targets associated with the former EU target of 32% set in 2019 (i.e. France and the Netherlands). Faster policy implementation would be needed to reach higher

IEA. CC BY 4.0.

NECP ambitions. While these impediments are also present in other countries, the extent of their impact on progress towards meeting any new goals remains to be seen when their new targets are defined in June 2024. Nonetheless, Europe's challenges are not insurmountable, governments can overcome them with prompt policy actions as outlined below. Should countries act we could see growth accelerate by 32%; higher (701 GW) by 2028.

Grid congestion and lengthy connection queues: Long grid queues due to complex application processes and inadequate network capacity are increasing project lead times in many countries and driving up costs for developers as they await licensing. For example, developers in Italy, Germany, the Netherlands, and Bulgaria have cited long grid connection queues as an issue, while grid operators in Greece and Hungary have stopped accepting applications for large-scale systems altogether.

Some countries have taken steps in the past year to shorten grid queues. For example, some governments have published maps of available locations for developers (e.g. Austria and Denmark), simplified grid connection requirements for residential systems (e.g. Germany), and published guidelines to clarify processes (e.g. Portugal). To address congestion, Spain has mandated that grid operators include a minimum amount of distributed generation in their network investment plans, while other countries have increased their budgets for transmission investment. Incentivising storage by subsidising behind-the-meter batteries and holding auctions for large-scale storage (Greece) are also being used to increase system flexibility and accommodate more variable generation. In addition, the EU Grid Action Plan released in November 2023 identifies actions that key stakeholders can take to accelerate the pace of grid investment.

Policy actions to shorten grid queues include streamlining grid connection procedures; ensuring adequate network planning and investment; and tackling grid integration challenges.

Economic attractiveness of auctions: Several auctions have been undersubscribed in the past year, partly because their economic attractiveness is questionable in an increasingly uncertain price environment. Developers facing rising labour, equipment and financing costs have refrained from bidding in auctions due to uncertainty over the ability of contracts to account for inflation-related cost increases. In some cases, the business cases through other routes to market have provided more attractive returns.

For instance, in Spain only 46 MW of the 3.3 GW of capacity available had been awarded in the auction in November 2022, partly because the economics of unsubsidised projects were more appealing, and in the United Kingdom none of 4 GW of offshore wind on offer in the UK technology-neutral auction was

IEA. CC BY 4.0.

contracted because bidders found maximum bid prices too low. Inadequate ceiling prices have also been responsible for the awarding of low volumes in France, Greece and Poland.

However, policy responses have proven successful in attracting developers in other cases. In January 2023, Germany raised its solar PV ceiling prices to 25% higher than in December 2022, boosting the subscription rate for utility-scale ground-mounted solar PV from 68% in December 2022 to 100% in January 2023. Meanwhile, Ireland's first offshore wind auction for 3 GW in 2023 with inflation-linked contracts for 20 years at a maximum ceiling price of EUR 150/MWh was fully awarded (average contract price at USD 93.5/MWh), and in France the government changed its auction design to index contract prices to material cost increases incurred during the construction phase.

Policy actions to make auctions more economically attractive include adjusting auction ceilings to account for rising developer costs; incorporating inflation into contract prices; or allowing generators to gain revenues from the spot market.

Implementation of permitting reforms: Obtaining permits and licences for projects has been a long and not always successful endeavour in many countries due to complex processes; limitations on area available for development; administrative staff shortages; and social opposition. This has prevented developers from entering auctions, led to project abandonment, and delayed construction and commissioning.

However, since the European Commission released recommendations on permitting in May 2022 to help countries streamline their processes, many have simplified their permitting procedures; set clear permitting timelines; identified go-to areas; and removed some requirements for small projects (see the June 2023 Renewable Energy Market Update for detailed examples). In addition, the new RED III published in July 2023 assigned renewables the status of overriding public interest and introduced measures requiring certain permits to be issued within two years. The Commission also endorsed to the European Wind Charter which aims to streamline permitting. At a national level, some countries have started to make changes to the permitting regulations. However, the effectiveness of these reforms has been mixed.

In some countries, the impact has been visible: in Germany, for instance, permits for 6.6 GW of onshore wind were granted in the first eleven months of 2023 – almost 70% than the 3.9 GW issued in 2022 – owing to regulatory reforms in 2022. Meanwhile, Spain granted 25 GW of solar PV environmental assessments in January 2023 to meet new deadlines to maintain grid connection permits. Yet in other countries, translating legislation into action has been more challenging. In the United Kingdom, the government announced plans to remove a *de facto* ban

IEA. CC BY 4.0.

on wind permits but has yet to make progress, while in Romania new permitting reforms are being misinterpreted, resulting in the rejection of project applications.

Policy actions to help overcome permitting challenges include simplifying procedures, identifying priority areas, and allocating more resources to administrative processes.

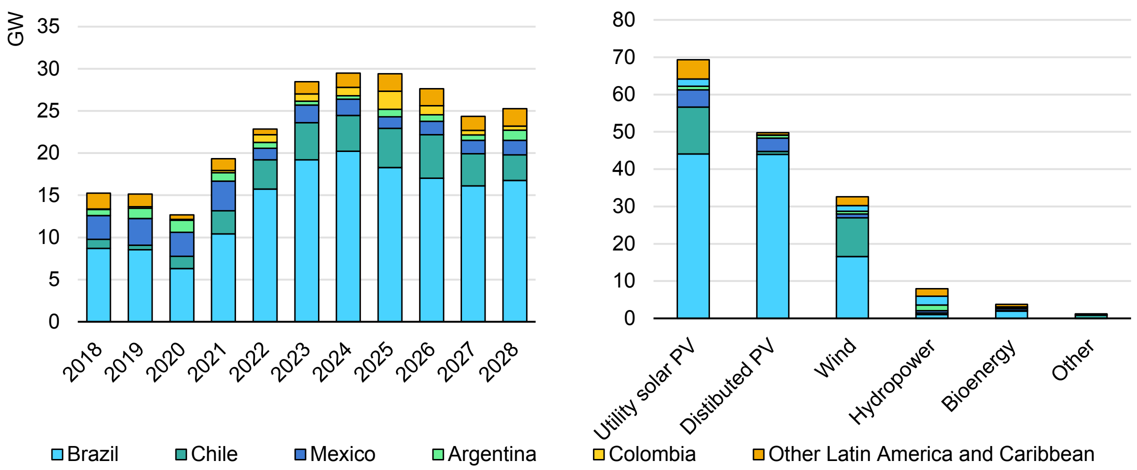
Latin America

Bilateral contracts and distributed solar PV in Brazil drive regional growth

Latin America will add over 165 GW of renewable energy capacity from 2023 to 2028. Four markets represent 90% of the region's additions: Brazil (108 GW), Chile (25 GW), Mexico (10 GW) and Argentina (4 GW). Solar PV leads capacity additions, followed by wind power. Large-scale hydropower development in the region has slowed, as most economically viable locations have been developed and some large projects have been delayed by permitting or financing concerns.

Capacity additions decline throughout the forecast period due to slower growth in Brazil, the region's largest market. Hydropower made up over half of additions in 2011-2016 but has since dropped significantly and will represent only 5% of all additions in the forecast period.

Latin America capacity additions by technology, and country additions by technology



IEA. CC BY 4.0.

Note: "Other" in right graph includes CSP, geothermal and capacity dedicated to hydrogen production.

Auctions are no longer the primary stimulant for utility-scale solar PV and wind additions, as development in major markets such as Brazil, Chile, Argentina and Mexico are now increasingly taking place outside of government-run auction

IEA. CC BY 4.0.

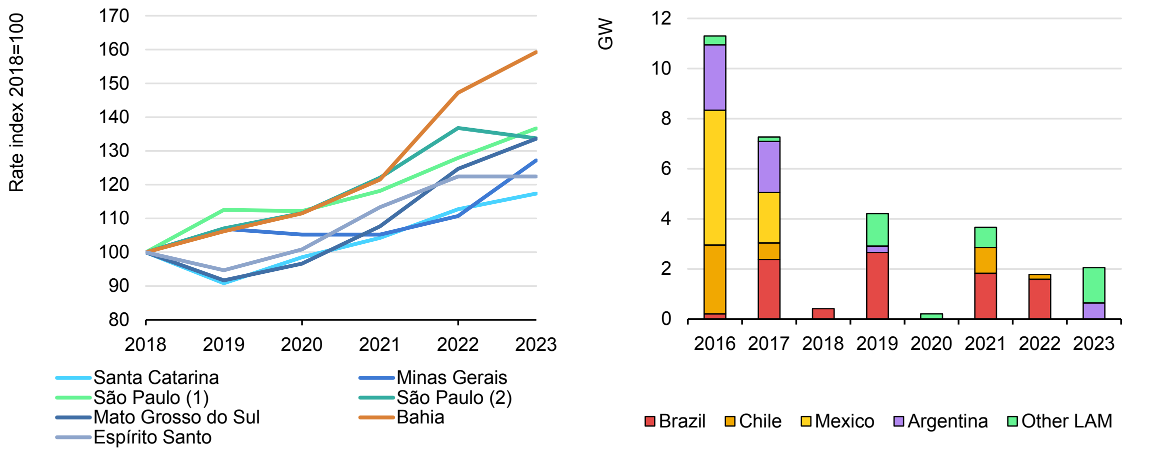
schemes. In Brazil, bilateral agreements in the free market enable over 85% of utility-scale solar PV and wind additions in the forecast period. In Argentina up to 80% of additions are from corporate PPAs, while Chile's majority of additions are through corporate PPAs or merchant projects.

Corporations are contracting more capacity through PPAs for greater price certainty and to reach corporate decarbonisation goals. However, smaller markets such as Ecuador, Guatemala and Honduras have been using competitive auctions to spur solar PV and wind deployment.

Brazil represents nearly 90% of the region's almost 50 GW of distributed solar PV additions. A generous net metering scheme led to a boom in distributed solar PV capacity, with the country adding over 15 GW since 2015. In January 2023, Brazil's net metering law was changed to gradually reduce generous remuneration. While in many markets drastic policy or compensation changes often lead to dramatic declines in new capacity, Brazil's distributed solar PV sector is expected to remain strong, with additions averaging more than 7 GW per year through 2028.

There are two reasons for continued distributed solar PV expansion in Brazil despite lower incentives. The first is that residential electricity rates have been rising since 2019 due to low hydropower output and increased demand. The second is that system costs remain low. Thus, the combination of these factors means that the payback period for residential systems has increased only moderately, from an average of just under five years to around five and a half years, helping drive growth.

Brazil distribution-indexed retail electricity rates for residential customers, 2018-2023, and renewable energy auction volumes by country, 2016-2023



IEA. CC BY 4.0.

Sources: IEA analysis based on tariff adjustment data from Celesc, Cemig, CFPL Paulista, ENEL Sao Paulo, Neoenergia Elektro, Neoenergia Coebla and EDP Brasil (left).

IEA. CC BY 4.0.

In the accelerated case, improving system integration, raising auction demand and minimising macroeconomic risks could produce 14% higher additions for Latin America. While auctions are no longer a primary growth driver in Brazil and Chile, increased demand and adjusted pricing could lead to higher participation, accelerating expansion in both countries. In Argentina, macroeconomic challenges hamper growth.

In addition, higher shares of utility-scale renewables and distributed solar PV have created system integration challenges. For instance, Chile has started incentivising energy storage systems to balance new variable renewable energy and reduce curtailment. To address transmission system constraints, Brazil recently held an auction for transmission development, connecting areas of high resource potential with demand centres. These efforts can accelerate deployment if incorporating energy storage systems is not cost-prohibitive in Chile, and if transmission grid upgrades are built on schedule in Brazil.

Sub-Saharan Africa

Nearly 64 GW of new renewable capacity is forecast for sub-Saharan Africa from 2023 to 2028, more than doubling the region's current installed capacity. The forecast has been revised up nearly 20% because of strong expansion in South Africa, which accounts for nearly 50% of additions in the region. Outside of South Africa, hydropower drives over 6 GW of additions in Ethiopia, distributed solar PV enables 5 GW of additions in Nigeria, and Angola and Kenya add over 2 GW of new renewable capacity each.

While solar PV and wind make up nearly 80% of new additions across the market, this mainly reflects additions in South Africa, which is responsible for the vast majority. South Africa's auction programme and the expansion of industrial and residential solar PV applications remain the key regional growth drivers.

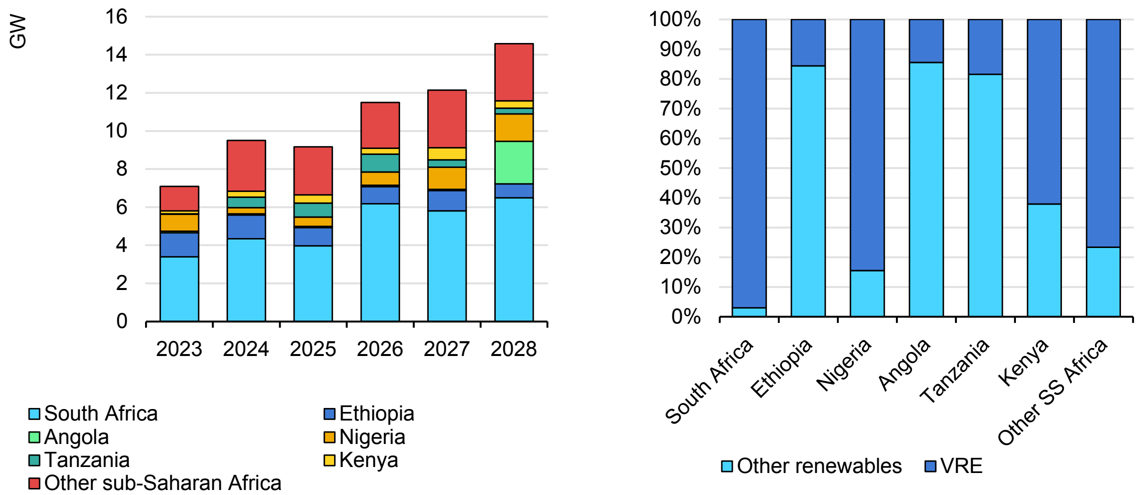
Thus, when South Africa is excluded, the regional forecast is revised down over 5% due to the lack of support programmes and limited project pipelines. Wind and solar PV installations make up just 40% of additions, as many countries are heavily reliant on large-scale hydropower. For instance, a single hydropower project in Angola is responsible for nearly 90% of the country's total renewable energy expansion over the forecast period, while two projects in Ethiopia contribute nearly 85% and Tanzania's renewable energy market expansion over the next five years is 80% dependant on hydropower. While large-scale hydropower projects can cost-effectively improve electricity access, they can take a decade or more to plan and build. As a result, annual additions can fluctuate following hydropower investment cycles.

While many sub-Saharan African countries have policies in place to accelerate solar PV and wind growth, they have met with varying degrees of success. For

IEA. CC BY 4.0.

example, Kenya's feed-in-tariff programme spurred multiple new solar PV and wind project announcements, but PPA renegotiations and land-rights issues led to project cancellations. And in South Africa, although auctions have been a key stimulant, delays in signing PPAs have led to project postponements. As a result, utility-scale solar PV and wind additions are heavily project-reliant in many markets, with development driven either by direct government investment (e.g. Ethiopia) or by one-off negotiations between an IPP and a government or utility (e.g. Kenya and Senegal).

Sub-Saharan Africa capacity additions and share of variable renewable energy in forecast additions



IEA. CC BY 4.0.

Notes: SS = sub-Saharan. VRE = variable renewable energy. Capacity additions refer to net additions.

Slow grid expansion in rural areas also creates opportunities for solar PV expansion, with off-grid solar PV additions totalling over 1 GW in our forecast. In many markets, rural electrification agencies are increasing the integration of these systems. For example, Nigeria's Rural Electrification Agency has leveraged both the public and private sectors to build mini grids across the country, electrifying communities, schools and hospitals with solar PV systems. International development banks and foreign governments supplement national programmes, providing additional financing and technical expertise. These combined efforts help increase electrification, especially in areas not served by a national grid.

Beyond stop-and-go policies, additional challenges in the region include off-taker risks, land access issues, currency risks and a lack of enabling infrastructure. In the accelerated case, effective policies, coupled with additional development bank and international aid agency-enabled programmes, could produce nearly 30% higher additions than the main case. Our accelerated case includes policy improvements such as holding tenders that grant land rights; building projects

IEA. CC BY 4.0.

adjacent to existing grid infrastructure; and providing additional financing mechanisms to enable more independent power producer projects.

Smooth, swift policy transitions can also facilitate higher additions. For example, Kenya is planning to transition from a system based on feed-in tariffs to an auction scheme. While the initial auctions have yet to be announced, firm pricing structures coupled with a reliable schedule would accelerate additions. In South Africa, pending legislation could enable additional IPP projects, further increasing investment.

Development financing could help de-risk wind and solar projects in sub-Saharan Africa

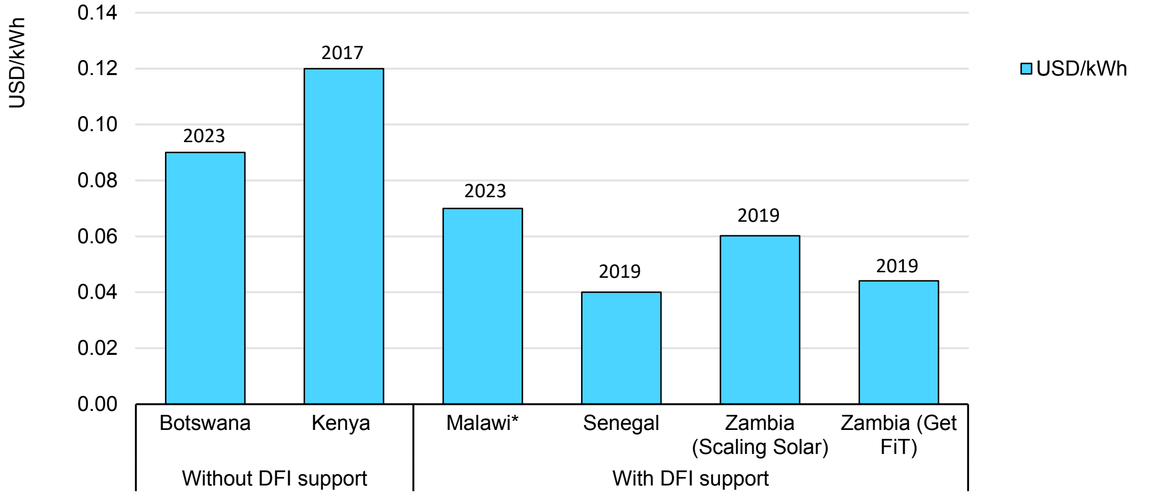
Accelerating renewable energy capacity growth in sub-Saharan Africa will require investment not only in new projects, but in infrastructure. Until now, programmes to increase renewable capacity have found creative solutions to work around the region's low amount of transmission and distribution infrastructure, such as the French Development Agency's proposal to develop solar PV installations along existing transmission lines. While this will allow for greater renewable energy capacity, it does not address the dearth of transmission and distribution infrastructure. Low network capacity is thus a major forecast challenge, as projects may need to wait years for grid connection or may be forced to cancel due to lack of network access.

Enabling and financing both generation and network development is therefore crucial to raise capacity additions in Africa, requiring higher collaboration between financiers and governments. Thus, to better align development of both generation and critical infrastructure, African governments and international actors signed the Nairobi Declaration in 2023. The declaration creates a framework to restructure debt and issue new financing for, among other activities, renewable energy development. It also proposes better alignment of concessional financing and government policies to enable renewable energy deployment. As with generation projects, these types of financing arrangements can address project risks, leading to more cost-effective pricing.

For development or aid organisation-backed projects, contract prices can be 40-50% lower than for PPAs with governments or utilities because they address some risks associated with project development in the region, including currency and off-taker concerns. However, while these projects do increase renewable energy capacity, they are often nonrecurring, leading to boom-bust development cycles. In addition, they may do little to address larger system needs, leading to unintended consequences by potentially putting strain on an existing system.

IEA. CC BY 4.0.

Sub-Saharan Africa contract prices for solar PV installations, with and without DFI support



IEA. CC BY 4.0.

*Cost estimated based on publicly available information.

Note: DFI = development finance institution.

The co-ordinated planning and pairing of development and aid organisation financing with grid development can have not only a short-term impact (i.e. immediate system upgrades for reliability and security of supply), but also a lasting effect on the region (i.e. preparing enabling infrastructure for longer-term investment). Instead of projects needing to be strategically located to connect to the grid, expanded networks would enlarge development areas, boosting availability.

Guarantees and concessional financing provided by international organisations can address two forecast uncertainties. First, they can reduce the risk premiums associated with development in sub-Saharan Africa. By aligning policy priorities with international financing, the reduced risk could transfer to government-led projects, helping create a sustainable policy environment. This would enable the achievement of policy goals and establish the skilled workforce needed for continued renewable energy development while also developing existing markets, leading to better system planning. Second, increasing concessional financing to support transmission and distribution grid development can lower connection risks. Should financing, grid connection and other additional risks such as land access be addressed, our accelerated case sees over 30% higher growth compared to our main case.

Middle East and North Africa

Renewable capacity expansion in the Middle East and North Africa is expected to increase 62 GW in 2023-2028. Over the next five years, the pace of growth is

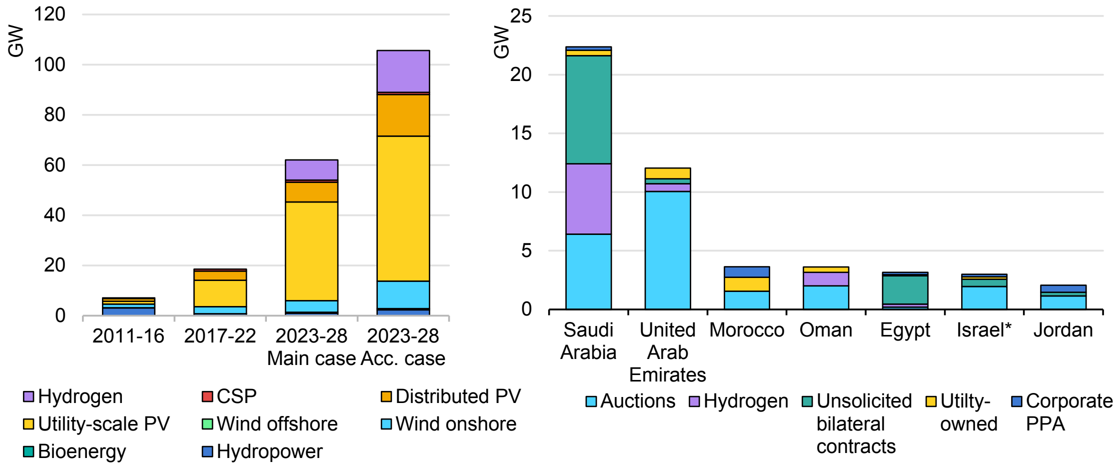
IEA. CC BY 4.0.

expected to accelerate to more than three times the previous five-year period, with solar PV making up over 85% of the increase. Onshore wind and concentrated solar power also contribute. More than one-third of the growth will be in Saudi Arabia alone, followed by the United Arab Emirates, Morocco, Oman, Egypt, Israel[3] and Jordan. These seven countries account for over 90% of the region's growth.

Competitive auctions are the leading stimulus for renewable capacity expansion in the region, accounting for 35% of growth. Almost all countries have implemented government tenders to procure private investment for utility-scale PV, onshore wind or CSP. Owing to the region's rich solar resources, attractive economies of scale for large projects and advantageous financing conditions, these tenders have produced some of the lowest bid prices in the world for solar PV.

However, opening the auctions, qualifying bidders, selecting winners and signing PPAs can sometimes take several years, impeding faster growth. As a result, expansion through mechanisms other than competitive auctions (i.e. unsolicited bilateral contracts with utilities, and corporate PPAs in the markets that allow them) has been increasing.

Middle East and North Africa capacity additions, and primary drivers of utility-scale growth by country



IEA. CC BY 4.0.

* 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.

Notes: Procurement refers to the mechanism by which electricity generation is bought and sold. This analysis only covers procurement methods for the sale of electricity generation; it excludes any additional subsidies on capital costs, such as tax credits, accelerated depreciation, rebates, grants, etc. Hydrogen refers to renewable capacity dedicated to hydrogen production.

[3] 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.

IEA. CC BY 4.0.

source of growth in the region owing to large projects earmarked for export in Saudi Arabia, Oman and the United Arab Emirates. In fact, hydrogen accounts for more than 13% of the region's renewable capacity growth thanks to government policies to stimulate development for trade. Good solar resources, land availability and existing port infrastructure create favourable conditions for economically attractive renewable hydrogen to be shipped to demand centres in Europe and Asia.

Nevertheless, growth could be 70% higher with three main improvements in the region. The first is faster procurement of utility-scale capacity through competitive auctions. Announcing future auctions with key dates for the selection process, and implementing them in a timely manner, would accelerate project development as well as increase investor confidence. Publishing long-term auction schedules detailing planned volumes and dates would also provide longer-term visibility for investors.

Second, introducing cost-reflective end-user tariffs would make distributed solar PV installations more financially attractive. Finally, boosting system flexibility through storage and increasing the contractual flexibility of existing fossil fuel assets would allow for increased deployment of variable renewables.

Technology, market and policy trends

Costs, economic attractiveness and competitiveness

The competitiveness of onshore wind and solar PV will continue improving

Despite investment costs having risen due to elevated commodity prices, the generation costs of new solar PV and onshore wind installations (excluding system costs) are mostly lower than for new fossil fuel-fired plants. In 2022, an estimated 96% of newly installed utility-scale solar PV and onshore wind capacity had lower generation costs than coal and natural gas facilities. However, offshore wind outside the European Union is currently not competitive with fossil fuel alternatives.

Over the forecast period, wind and solar PV costs are expected to continue declining. In the second quarter of 2023, the price of PV modules from China was almost 40% lower than in 2022 (see wind and solar PV manufacturing section), and supply-demand dynamics indicate further drops in the next five years. For wind, investment costs are expected to remain high in the short term due to supply chain challenges and the weak financial health of major Western manufacturers. However, this translates into only a 10-15% increase in generation costs for

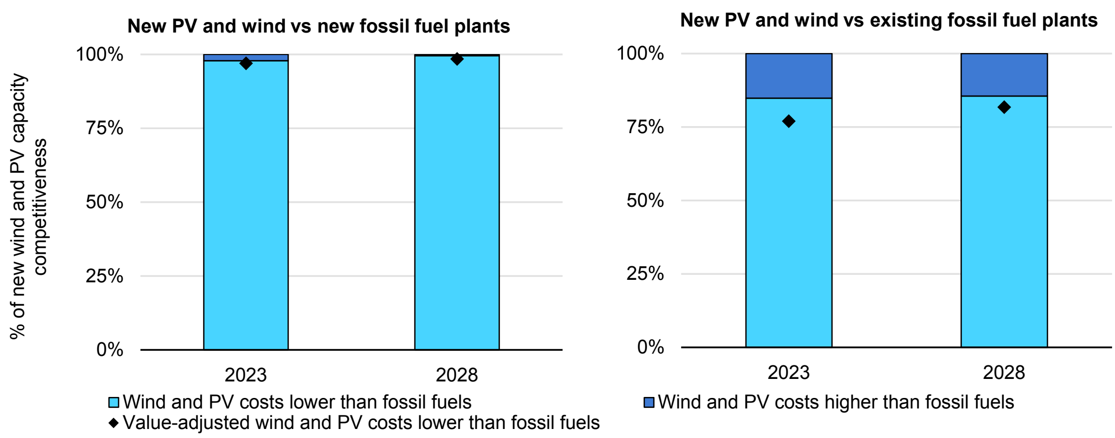
IEA. CC BY 4.0.

onshore wind power plants and does not really change their competitiveness with fossil fuel alternatives, as their costs have also risen.

Wind and solar PV systems will become more cost-competitive during the forecast period. In fact, we estimate that by 2028 almost all wind and solar PV capacity deployed will provide lower generation costs than coal and natural gas alternatives for new plants. Current cost decline trends in China indicate that in the next five years, new offshore wind plants could be more economically attractive than new coal plants, helping China meet its official net zero goal.

Generation costs of new onshore wind and utility-scale solar PV are also becoming increasingly lower compared with existing fossil fuel-fired plants. In 2023, three-quarters of newly installed solar PV and onshore wind capacity offered cheaper power generation than existing fossil fuel facilities. In China, India and the European Union, the levelised cost of energy (LCOE) from solar PV plants is below the marginal cost of generating electricity from existing coal- and natural gas-fired plants. It is estimated that by 2028, over 80% of newly installed variable capacity will provide electricity more affordably than existing fossil fuel alternatives.

Share of utility-scale wind and PV with lower levelised cost of energy than new coal and natural gas power plants (left) and existing plants(right), 2022-2028



IEA. CC BY 4.0.

Notes: The analysis in this figure represents around 85% of global renewable capacity additions in 2023 and 2028. The cost comparison considers the World Energy Outlook's STEPS scenario published in October 2023.

Source: IEA (2023), World Energy Outlook 2023.

However, assessing competitiveness based on generation costs for both new and existing plants can be misleading for variable renewable energy technologies, as they need to be accompanied by dispatchable and flexible power plants or coupled with storage at higher penetration levels. While existing dispatchable capacity (e.g. natural gas-fired and hydropower) already offer ample flexibility in many

IEA. CC BY 4.0.

countries, short- and long-term electricity storage along with demand-side management and grids will be critical to cost-effectively integrate wind and PV.

The IEA uses the value-adjusted LCOE (VALCOE), which is a more complete metric of competitiveness for power generation technologies than the LCOE alone, as it combines a technology's LCOE with the simulated value of three system services: energy, flexibility and capacity. According to the IEA analysis, the value of variable technologies will fall as their use becomes more widespread, especially for solar PV. Accordingly, the VALCOE of utility-scale PV could be as much as double the LCOE calculations depending on the country's technology mix and renewables penetration. A rising share of variable renewables leads to higher cannibalisation effects, which tend to make variable renewables less competitive than the LCOE alone would suggest. These effects are reflected in a higher VALCOE for solar PV and wind (compared with the LCOE) and a lower or stable VALCOE for dispatchable sources of electricity in the future. Even when considering increasing flexibility and reliability requirements, new utility-scale solar and onshore wind power plants' in the United States, European Union, China and India will still be lower than fossil fuel alternatives at the end of the forecast period. Although VOLCOE is a fuller and more accurate measure of competitiveness, it is not all encompassing: it does not yet account for network integration such as transmission and distribution grid enhancements.

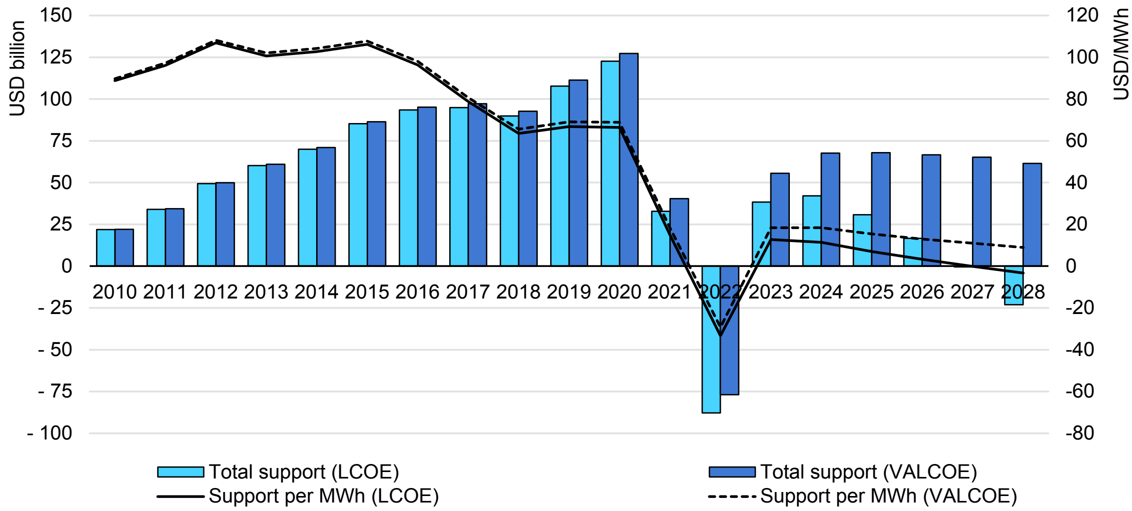
Global support for wind and solar PV is set to decline significantly despite accelerating deployment

The increasing competitiveness of solar PV and wind has implications for both governments and consumers because it leads to reduction of public support used to accelerate deployment of renewables. Typically, governments have provided such support based on renewable electricity cost differential against a reference price, usually related to fossil fuel generation costs. For instance, many EU member states' support policies were focused on covering the gap between renewables' contract tariffs and wholesale electricity price. In China, the government calculated subsidies considering the difference between fixed renewable tariffs and provincial benchmark power prices.

IEA. CC BY 4.0.

The analysis presented in this section is aimed at estimating the implied support required by solar PV and wind power, calculated as a difference between generation costs from these technologies and from fossil fuels[4]. Global annual net value of that support for all capacity installed since 2005 more than quintupled between 2010 and 2020. It was a result of accelerating renewables deployment and still high share of generation from older, more expensive installations. However, global support levels declined from about USD 125 billion[5] in 2020 to about USD 80 billion of savings in 2022 marking a change in the long-term trend. There were two main reasons behind this: (1) the energy crisis caused by the Russian Federation's (hereafter "Russia") invasion of Ukraine lead to an unprecedented surge in natural gas and coal prices, especially in Europe; (2) a step increase in low-cost VRE generation due to record capacity additions.

Global estimated net annual support for solar PV and wind electricity generation, 2010-2028



IEA. CC BY 4.0.

Notes: LCOE = levelized cost of electricity. VALCOE = value-adjusted LCOE.
Source: IEA analysis based on IRENA, EIA, Argus, Bloomberg LP, World Energy Outlook 2023.

[4] Analysis presented in this section focuses on estimating the difference between average electricity generation costs from wind and PV plants and from fossil fuel power plants. Analysis was conducted for China, the United States, European Union member countries, United Kingdom and India, where average spot prices of hard coal, natural gas and CO_2 emission allowances were used to estimate the variable generation costs of displaced fossil fuel generation. These countries represent about 77% of total VRE generation in 2023 and 81% in 2028.
Costs of energy from PV and wind were estimated in two ways. LCOE approach assumed that VRE generation costs are equal to Levelized Costs of Electricity, therefore assuming simple replacement of one type of electricity with another. In VALCOE approach, VRE costs were calculated based on Value-Adjusted LCOE, where a value of electricity to the power system is considered. This approach has the highest impact on solar PV generation costs in the power systems with high VRE penetration and a moderate impact on wind costs.
Conducted analysis is an estimate with multiple sensitivities. Following factors, which were not taken into account could have resulted in overestimation of support value by assuming lower reference fossil fuel generation costs: (1) possible increased demand for fossil fuels leading to higher prices in a scenario of lower VRE generation; (2) possible cases when VRE expansion removes a need for deployment of new fossil fuel power plants; (3) subsidies received by fossil fuel mining industry and generators; (4) prioritizing displacement of generation from the most expensive fossil fuel power plants following the merit order.

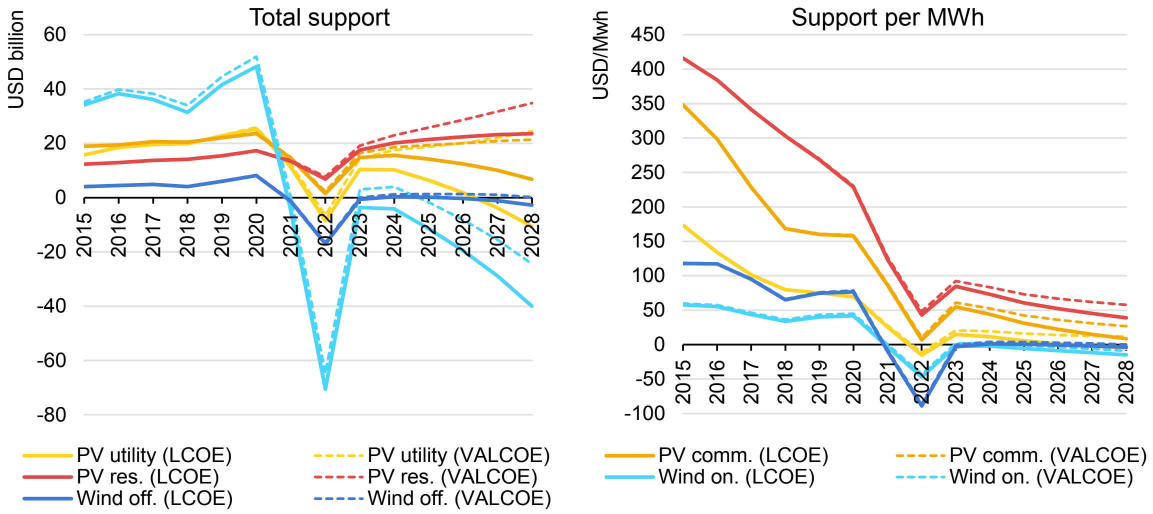
[5] All monetary values are expressed in 2022 USD.

IEA. CC BY 4.0.

In 2023 fuel prices returned to pre-crisis levels in the United States, China and India but remained elevated in the European Union. As a result, global net support returned to positive value but only 30-40% of the 2020 level. In a scenario assuming continuation of costs decline trend for new renewables and the price environment for fossil fuels based on the second half of 2023, global support for PV and wind power could turn into savings starting in 2027. Even in an analysis approach considering the changing value of VRE for the power system (VALCOE approach), the required global support will decline to around USD 50 billion by 2028, half of the estimated annual average over 2015-2020. This translates to average costs difference between electricity generation from fossil fuel plants and VRE decreasing from close to 70 USD/MWh in 2020 to -3 USD/MWh (savings) in LCOE approach or about 10 USD/MWh in VALCOE approach by 2028.

Average global LCOE decreased from USD 105/MWh to USD 35/MWh for onshore wind and from USD 450/MWh to USD 50/MWh for utility-scale PV between 2010 and 2022. Starting from 2019, generation costs for new VRE plants started to become cheaper than existing fossil fuel plants in many countries, especially when fossil fuel generation costs increased drastically at the end of 2021 and in 2022. In the high fossil fuel price environment of 2022, in European Union almost all installed wind capacity and most of utility-scale PV deployed since 2013 had provided cheaper electricity than coal and natural gas plants.

Net global support for solar PV and wind electricity generation, total (left) and per MWh of renewable electricity generation (right), 2015-2028



IEA. CC BY 4.0.

Notes: LCOE = levelized cost of electricity. VALCOE = value-adjusted LCOE. Wind on. = Wind onshore. Wind off. = Wind offshore. PV comm. = PV commercial. PV res. = PV residential.

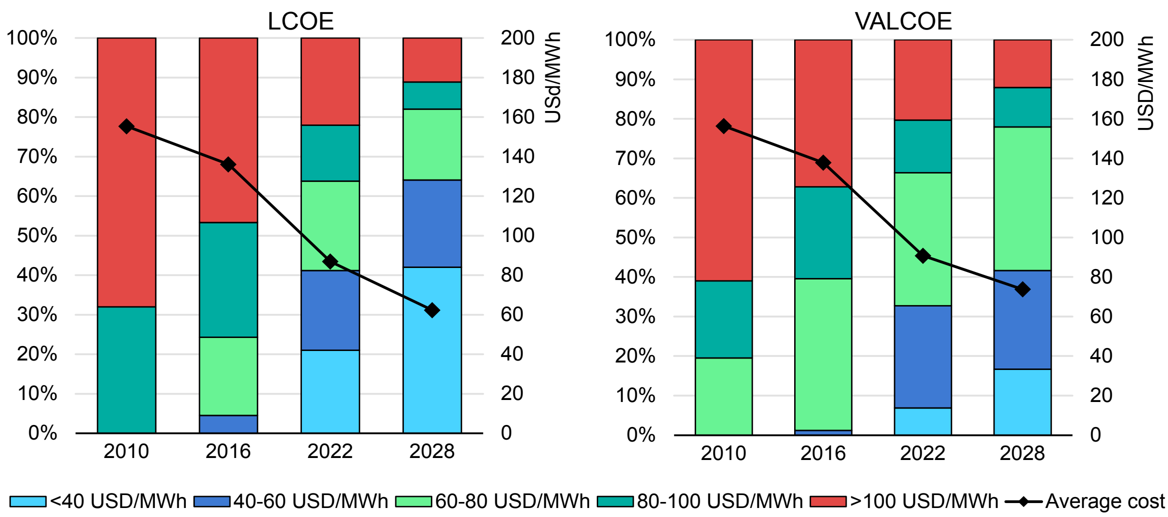
Source: IEA analysis based on IRENA, EIA, Argus, Bloomberg LP, World Energy Outlook 2023.

IEA. CC BY 4.0.

Over 2011-2020, onshore wind was responsible for about 40% of global net support for VRE, mostly due to its large share in wind and PV electricity generation. At the same time, onshore wind support per MWh of generated electricity remained the lowest compared to solar PV. In 2022, onshore wind provided over USD 70 billion of net savings globally, mostly in Europe. Technology's low generation costs and higher system value (compared with solar PV) are expected to provide savings throughout the forecast period both in LCOE and VALCOE analysis approach.

Utility-scale PV is expected to start generating net savings in 2027 in LCOE approach. However, solar PV's value to the system falls drastically at increasing generation shares, which is expected to be the case in many markets, especially in Europe and China. Based on this lower value, utility-scale projects may on average need USD 10/MWh of support in 2028. For distributed solar PV, generation costs are higher than large-scale applications. As a result, it is estimated to account for most of the global support to renewables in 2023-2028.

Share of global PV and wind electricity production by generation costs, LCOE (left) and VALCOE (right) approach, 2010-2028



IEA. CC BY 4.0.

Notes: LCOE = levelized cost of electricity. VALCOE = value-adjusted LCOE.

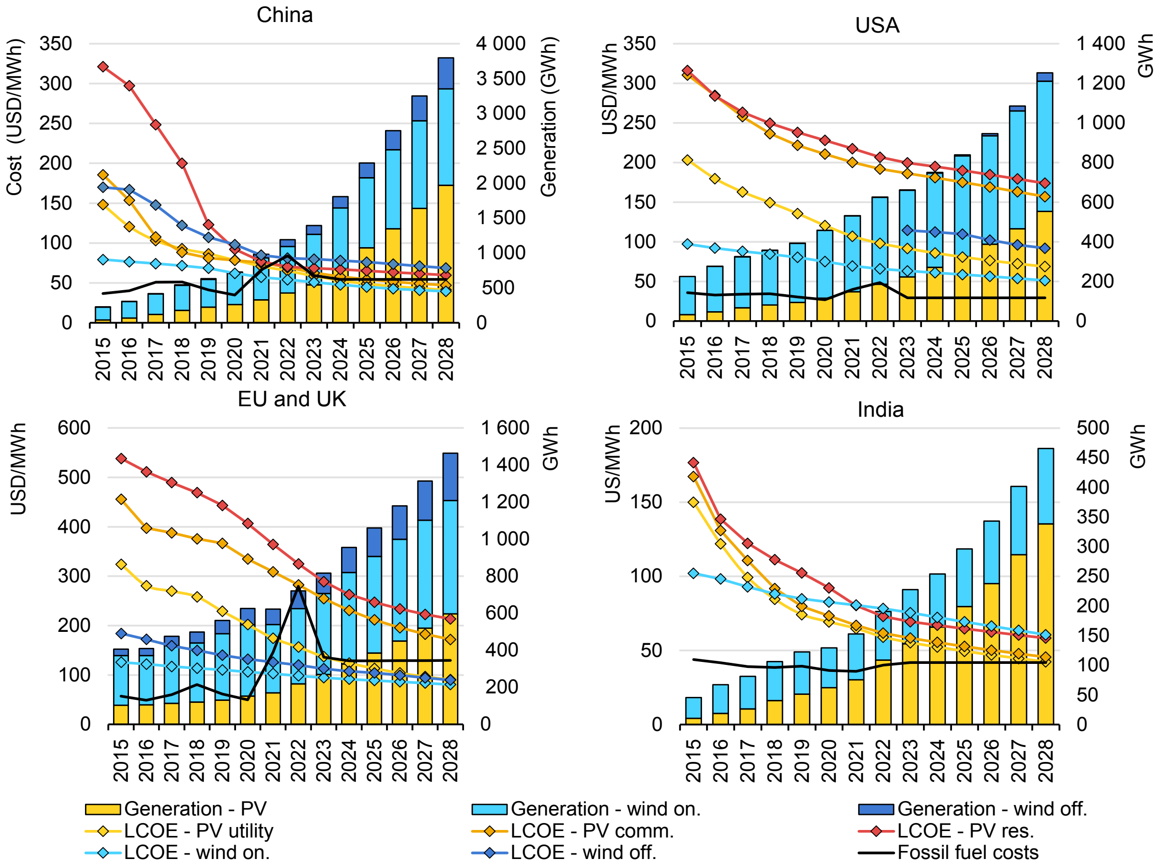
Source: IEA analysis based on IRENA, World Energy Outlook 2023.

Renewable generation costs analysis described above includes all PV and wind systems commissioned since 2005 and assumes that their generation costs remain unchanged throughout plants' lifetime. The trend of decreasing costs of new wind and PV and accelerating capacity additions, leads to increasing share of low-cost generation in total VRE mix. The average cost of VRE generation is expected to decrease from about USD 155/MWh in 2010 to USD 60/MWh in case of LCOE and USD 75/MWh when considering VALCOE in 2028.

IEA. CC BY 4.0.

In 2022, about 20% of all wind and PV had generation costs below USD 40/MWh, lower than variable generation cost of most hard coal and natural gas power plants in Europe, China and India. This share is expected to reach 40% in 2028 with an increasing number of VRE plants generating savings. However, the share declines to about 15% when considering their value to the system.

Average cost of VRE and displaced fossil fuel generation (LCOE approach), total VRE generation, 2015-2028



IEA. CC BY 4.0.

Notes: LCOE = levelized cost of electricity. Wind on. = Wind onshore. Wind off. = Wind offshore. PV comm. = PV commercial. PV res. = PV residential.

Source: IEA analysis based on IRENA, EIA, Argus, Bloomberg LP, World Energy Outlook 2023.

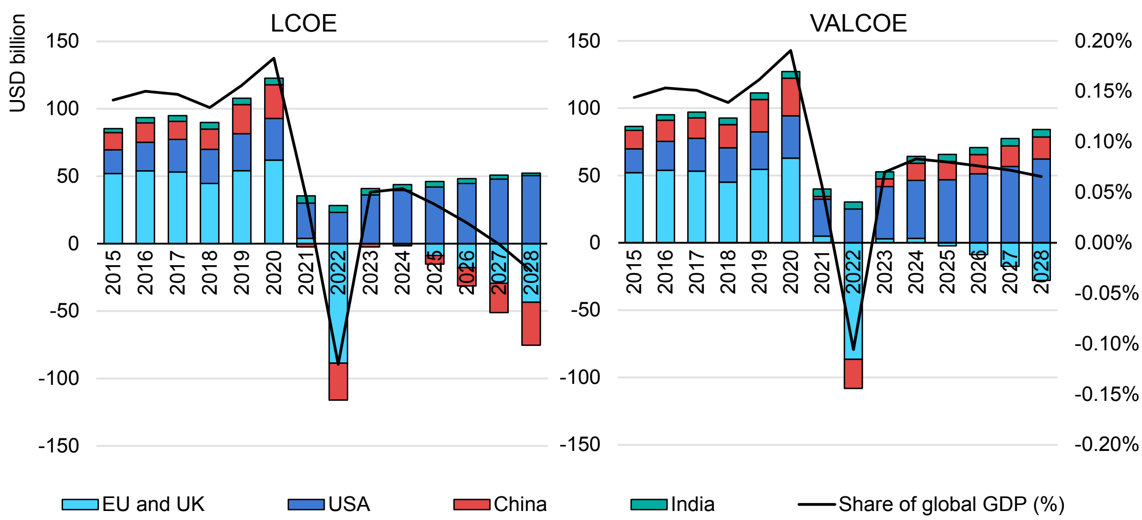
Until 2020, the European Union and the United Kingdom were responsible for over half of total support for wind and PV generation, mostly due to early deployment (especially small scale residential and commercial PV) at higher generation costs. However, during the energy crisis in 2021-2022 VRE has allowed to achieve an estimated USD 85 billion of savings, because of sharp increase in fossil fuel prices. If fossil prices remain at levels observed in the second half of 2023, onshore wind and solar PV are expected to provide savings even when their lower value to the power system is considered.

IEA. CC BY 4.0.

In China, record low wind and solar PV generation costs in recent years and the expected continuation of accelerating capacity additions lead to significant decrease in overall annual support over the forecast period. However, considering it's VALCOE, solar PV could need some support depending on provincial VRE penetration levels.

In India, accelerating deployment of VRE at low generation costs is offsetting more expensive deployment from past years, keeping the overall support at relatively low level. The United States, on the other hand, has one of the lowest fossil fuel generation costs among analysed geographies, therefore VRE deployment will continue to depend on increasing public support in the form of tax incentives over the forecast period.

Net global support for solar PV and wind electricity generation by country or region, LCOE (left) and VALCOE (right) approach, 2010-2028



IEA. CC BY 4.0.

Notes: LCOE = levelized cost of electricity. VALCOE = value-adjusted LCOE.

Source: IEA analysis based on IRENA, EIA, Argus, Bloomberg LP, World Energy Outlook 2023.

Beyond the forecast period, the support required for wind and PV is likely to decline, with many countries seeing savings driven by low cost renewables and the replacement of older installations. This will drive the average cost of renewable electricity down. At the same time, inclusion of greenhouse gas emissions in fossil fuel generation costs planned in many countries is likely to further increase the competitiveness of VRE.

Policy and markets

Although renewable energy technologies are becoming more cost-competitive, policies remain key for attracting investment and enabling deployment. Roughly

IEA. CC BY 4.0.

87% of global renewable utility-scale capacity growth in 2023-2028 is expected to be stimulated by policy schemes. Policy-driven deployment refers to capacity for which a government policy is the primary driver for the investment decision, for example, a policy that affects remuneration for power or reduces tax liability or introduces a purchasing obligation to meet government targets.

The two most prominent policies have been administratively set tariffs for remuneration (wherein the government offers developers a fixed tariff or premium) and competitive auctions (wherein the government puts a set amount of capacity up for bid and sets a limit on what it will pay for the contracted power). The leading source of auction-driven growth are two-way fixed contracts for difference, entirely driven by Europe where they account for more than one-third of the region's utility-scale renewables growth. Tax credits, a third policy option, raise the economic attractiveness of a project significantly by reducing the developer's tax liability. Utility-owned projects in regulated markets are a fourth form of policy-based deployment, as the investment decision is likely influenced by the regulatory environment by default.

IEA Renewable energy procurement and policy categories

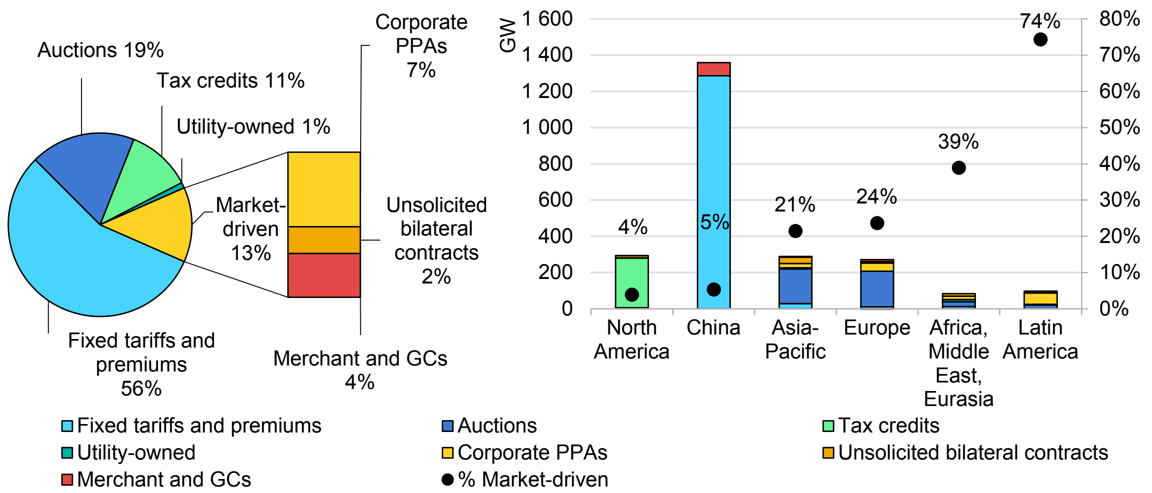
Type	Name	Primary driver
Policy-driven	Utility-owned project	State-owned utility investments for cost recovery or obligation to meet targets
	Fixed tariffs and premiums	Administratively set tariffs offered to developers
	Competitive auctions	Government solicitations for power using tenders with competitively set tariffs
	Tax credits	Reduced tax liability
Market-driven	Unsolicited bilateral contract	Bilaterally negotiated contract between a developer and utility
	Merchant	Revenues from the wholesale market
	Corporate PPA	Bilaterally negotiated contract between a developer and end user
	Green certificates	Revenues from the wholesale and green certificates market

Conversely, market-driven procurement is expected to account for just 13% of global renewable capacity growth. Market-driven deployment refers to that for which government policy does not directly influence the investment decision, such as bilaterally negotiated contracts (PPAs) between IPPs and corporate consumers (CPPAs) (7% of market-driven expansion), unsolicited bilateral PPAs with utilities (2%), and merchant projects and remuneration from certificate schemes (4%).

IEA. CC BY 4.0.

The high global share of policy-driven deployment comes largely from China, where policies underpin 95% of the country's growth. For instance, China is forecast to deploy around 1 285 GW of capacity almost entirely from administratively set fixed tariffs for 15-20 years based on the provincial benchmark electricity price, mostly defined by coal generation. Competitive auctions with a budget cap at the national level were held in 2020 but have since been stopped as the government phased out subsidies for utility-scale wind and solar PV. However, market-based deployment, accounting for 5% of the expansion, is expected to grow, thanks to the new green certificate regulations introduced in both 2022 and 2023 to facilitate interprovincial trade and track progress in meeting provincial renewable energy targets.

Utility-scale renewable electricity capacity by primary driver, 2023-2028



IEA. CC BY 4.0.

Notes: GC = Green certificate. Primary drivers refer to the financial incentive or revenue stream by which the investment decision is made. In some markets, projects can benefit from multiple financial incentives and/or stack different revenue streams, but data in this analysis are classified based on assumptions of which incentive or revenue stream most affects the business case for investment. For example, if a project is awarded through a government-held contract-for-difference (CfD) auction, the entire project is assigned to that category regardless of it having other revenue streams such as a corporate PPAs or merchant tail. Forecast refers to utility-scale projects for primary markets equivalent to 95% of global renewable electricity capacity growth.

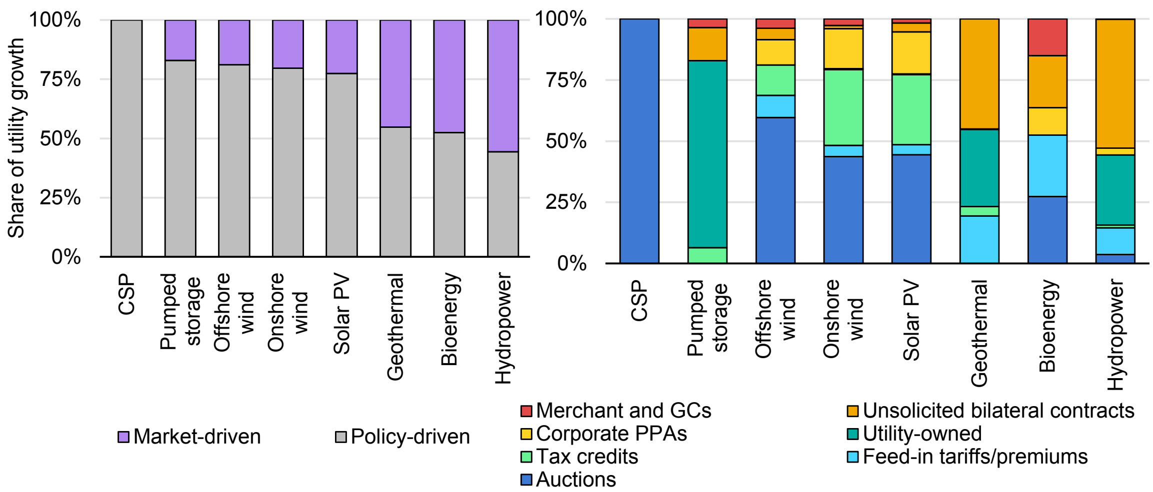
When China is excluded, market-driven procurement plays a larger role in global renewable capacity expansion, accounting for 23%. This share is even larger in Africa and the Middle East (39%) and Latin America (74%). In Latin America, this results largely from strong demand for corporate PPAs in Brazil (where high electricity prices and company sustainability goals are boosting demand from large consumers) and merchant projects in Chile.

The high share of market-driven growth in the rest of the world is led by South Africa's corporate PPA market, owing in part to the need to reduce impacts of load shedding, and unsolicited bilateral contracts in Saudi Arabia and Egypt also

IEA. CC BY 4.0.

contribute. Both countries have auction systems for solar PV and wind, but PPAs are being signed more quickly through bilateral negotiations than through public procurement processes.

Renewable electricity capacity by technology and primary driver, excluding China, 2023-2028



IEA. CC BY 4.0.

Notes: CSP = concentrated solar power, GC = green certificate. Hydropower refers to conventional hydropower. Data represent global market growth by procurement type excluding China.

However, in North America, Europe and Asia-Pacific, most renewable capacity growth over the next five years will still be policy-based. In North America, the majority of additions are in the United States, where tax credits for investment or electricity production are the primary catalyst. While other policies (such as competitive auctions or obligated purchases) may also strengthen the business case, the tax credit is expected to be the main enabler for investment. In Europe, almost three-quarters of utility-scale growth is from competitive auctions, mostly for solar PV and wind. However, elevated wholesale electricity prices in Europe are making corporate PPAs and merchant projects more attractive in the region, led by Spain, Germany, Sweden, the United Kingdom, and Denmark.

Competitive auctions are also the dominant procurement method in Asia Pacific, led by India, Viet Nam and Korea, while feed-in tariffs also boost expansion in Japan and Chinese Taipei. Most market-driven growth in the Asia-Pacific region comes from unsolicited contracts for hydropower projects in India and Pakistan, and corporate PPAs in Australia for onshore wind and PV.

Excluding China, competitive auctions are the single largest catalyst of utility-scale renewable capacity additions between 2023 and 2028. However, this is largely due to their importance in solar and wind deployment, which account for 93% of

IEA. CC BY 4.0.

the utility-scale forecast. For other technologies, different policy and market drivers are more important.

CSP and pumped storage hydropower (PSH) have the highest shares of policy-driven growth in 2023-2028 due to the high upfront investments and challenging business cases of both technologies. For CSP, growth comes entirely from competitive auctions in Morocco, the United Arab Emirates and South Africa, most of which have state-backed financing to improve project bankability. For pumped storage, over 80% of the expansion is driven by state-owned utilities, mostly in single-buyer markets because price signals in liberalised markets do not provide a strong enough business case. Growth is led by India, Indonesia, Australia, Viet Nam, Morocco and the United Arab Emirates because of their need to increase storage capabilities and minimise overall system costs to integrate rising shares of variable renewable energy.

Despite having similar flexibility needs, Europe and the United States account for only 10% of PSH capacity growth. Securing investment in these markets is challenging because revenues are limited due to shrinking arbitrage opportunities and restricted access to capacity or ancillary service markets.

Although competitive auctions are the main catalyst of growth for variable renewables, they play a larger role in offshore wind procurement than for onshore wind and solar PV, which have slightly higher shares of market-driven growth. Conversely, only a handful of offshore wind projects commissioned by 2028 are expected to have most of their business model based on corporate PPAs or merchant revenues – namely projects in the Netherlands and Viet Nam.

While offshore wind projects in other markets have announced that their business models will be based on CPPAs and merchant revenues, it is likely they will also rely on revenues from competitive auctions. However, CPPAs could become more important in the offshore wind market as way to finance new projects awarded through non-price criteria.

For conventional hydropower and geothermal projects, higher shares of state-owned utility procurement result from their high upfront costs and the need to de-risk investment. For hydropower, half of the growth is stimulated by bilateral contracts in India, Pakistan and Indonesia, followed by state-owned utilities' investments in sub-Saharan Africa and Southeast Asia, and feed-in tariffs for large hydropower in Türkiye. For geothermal, half of the growth is covered by unsolicited contracts in Indonesia and Kenya, followed by state-owned utility investments in Tanzania, Ethiopia and the Philippines.

IEA. CC BY 4.0.

Meanwhile, just over half of bioenergy deployment results from policy stimulus, mostly feed-in tariffs in Türkiye and Japan and competitive auctions in Germany and the Netherlands. Market-based procurement is expected from unsolicited bilateral contracts in India and Sweden, and some merchant projects in the United Kingdom, Germany and Argentina.

High power prices and weak business cases in auctions spur unsubsidised growth in Europe

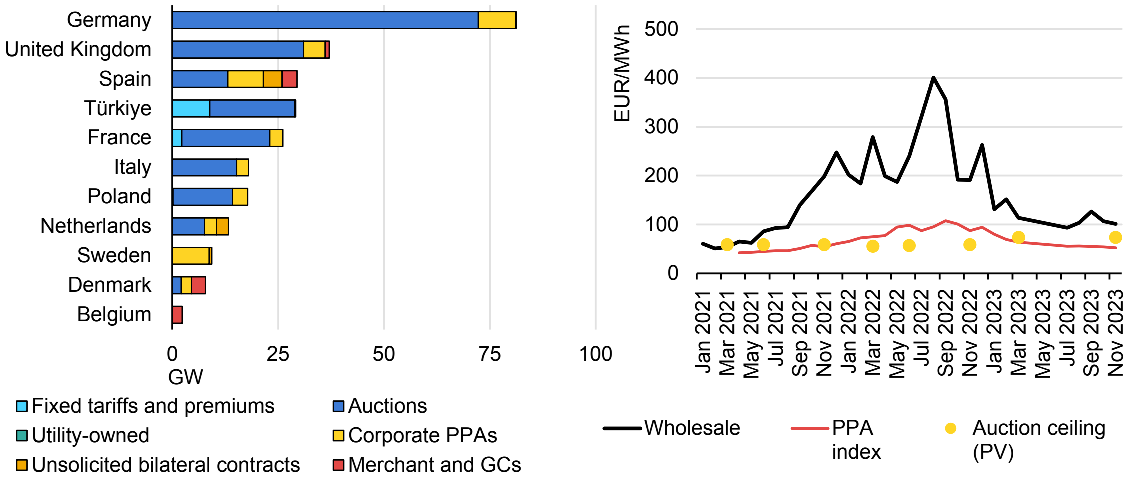
Competitive auctions will account for over 70% of Europe's renewable capacity growth between 2023 and 2028, led by Germany, the United Kingdom, France, Türkiye, and Italy. However, higher wholesale electricity prices indicate that market-based procurement could be increasingly important. In our forecast, one-fifth (53 GW) of Europe's renewable energy capacity in 2023-2028 is developed under corporate PPAs and projects with a merchant tail. This market driven growth will be led by traditional markets such as solar PV in Spain, and onshore wind in Sweden and the United Kingdom (with contributions from the emerging Italian and Polish markets). However additional deployment will also come from newer markets such as solar PV in Germany and Denmark.

Several factors explain the rise in market-driven procurement in Europe. The first is increased demand for corporate PPAs from large consumers to lock in low-cost power as a hedge against high, volatile power prices and to meet sustainability goals. Retail electricity rates in Europe have increased 15-20% on average since Russia's invasion of Ukraine, boosting corporate consumer appetite for renewable energy.

In parallel, corporate PPA prices jumped 50% from EUR 72/MWh in February 2022 to EUR 108/MWh by September 2022. Although prices have fallen 50% since their peak in September 2022 to EUR 52.2/MWh by November 2023, they nevertheless remain higher than pre-war levels and are still well below wholesale prices, thus they are expected to remain attractive to large consumers. In the first nine months of 2023, over 7 GW of capacity were contracted, in line with 2021 and 2022, signalling sustained growth.

IEA. CC BY 4.0.

Europe renewable electricity capacity procurement by type, 2023-2028 (left) and weighted average European wholesale electricity price, PPA index and auction ceiling prices



IEA. CC BY 4.0.

Note: GC = Green certificates.

Source: For PPA index, Pexapark (2023), PPA Times.

The second reason for the increase in corporate and merchant activity is that, in some markets, developers are finding the economics more attractive than contracts offered in competitive auctions. Low ceiling prices and a lack of inflation-indexed contracts have been linked to auction undersubscription in several markets because developers were able to obtain higher prices with corporate PPAs. For example, solar PV ceiling prices in Germany's undersubscribed auctions in 2022 were in the range of EUR 56-59/MWh, at least 26% below the European average CPPA and one-fifth the average wholesale price. As soon as the ceiling was raised to EUR 73/MWh in 2023, the auctions returned to full subscription.

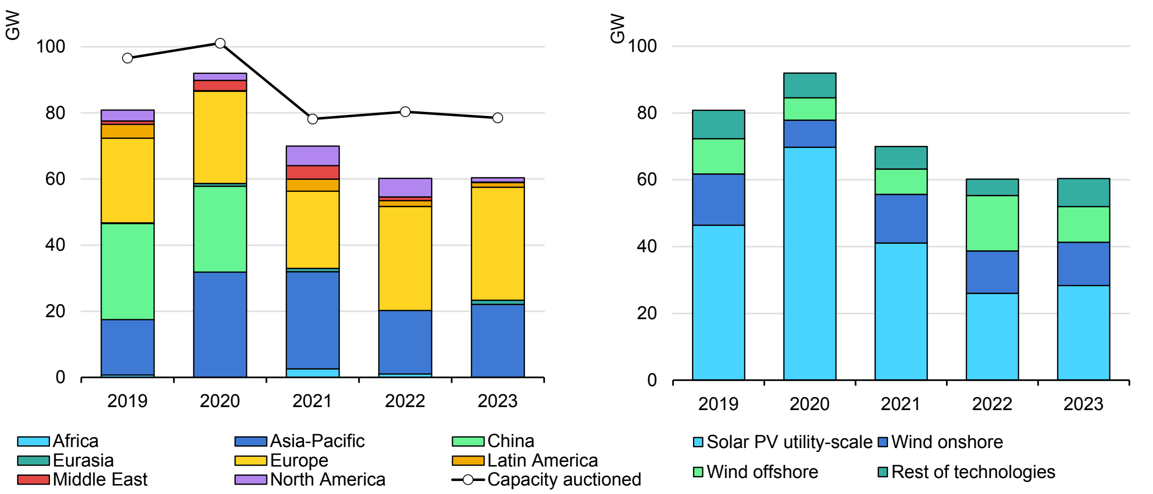
However, some uncertainties are associated with market-driven growth. One is whether corporate PPA prices will remain attractive to developers. Contract prices have fallen 50% since the peak in 2022 and some countries have therefore raised auction ceilings and adjusted contracts to account for rising costs, potentially making auctions more attractive to developers. Another uncertainty for projects with merchant offtake is the risk of price cannibalisation - i.e. when wholesale marginal prices go to zero or negative values in periods of excess solar and wind generation - and curtailment in markets with high renewable energy penetration. In addition, future demand cannot be guaranteed, as the number of very large consumers is limited and smaller companies with less demand are considered higher-risk off-takers. However, this barrier may be addressed by the European Commission's electricity market reform, which could enable the pooling of demand and state-backed guarantee schemes.

IEA. CC BY 4.0.

Auction trends

Awarded renewable capacity in competitive auctions in 2023 was the same level as in 2022. In Asia-Pacific, Europe and Eurasia awarded auction volumes increased offsetting lower contracted capacity in other regions. From a technology perspective, the tendered offshore wind capacity dropped by more than one-third worldwide following the record level achieved in 2022, the largest decline of all renewable technologies. Awarded onshore wind capacity slightly increased by 2%, and utility-scale solar PV grew by 7%.

Global renewable energy auction results by region (left) and by technology (right)



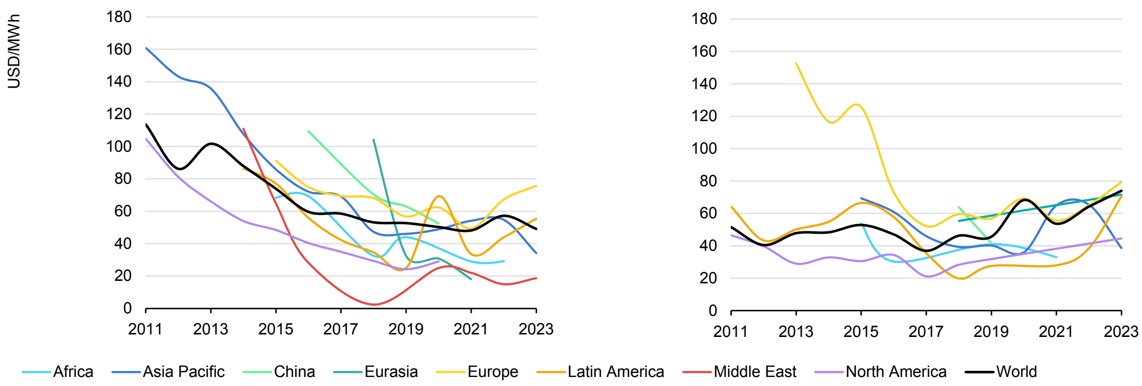
IEA. CC BY 4.0.

Note: For China, these graphs cover only centrally held competitive auctions; provincial auctions are excluded because capacity and price data for them are limited. The region Asia-Pacific does not include China.

The combination of high commodity prices, escalating investment costs and inflation has resulted in higher contract prices for solar PV and onshore wind. In several auctions, developers found the ceiling or reference prices too low, leading to undersubscriptions, with some tenders having no participants at all. The offshore wind sector has also been affected by emerging macroeconomic and supply chain challenges, although auction performance varies significantly from one country to another.

IEA. CC BY 4.0.

Average auction prices by region for solar PV (left) and onshore wind (right)



IEA. CC BY 4.0.

Note: Asia Pacific excludes China.

Globally, the overall subscription rate slightly improved in 2023 compared with 2022, with 77% of offered capacity being allocated. Auction success depends on:

- Volumes offered: the amount of capacity, energy, or budget made available in the auction, reflecting the country's commitment and ambition to develop these technologies or achieve specific targets.
- Policy certainty: encompasses factors such as permitting times and the clarity of participation requirements for tenders. Clear and predictable policies are crucial to attract developers.
- Price ceiling: the maximum price limit and its relationship to project costs. An appropriate balance is necessary to ensure the economic feasibility of projects.
- Indexation to inflation: reduces risk for developers by accounting for the potential erosion of project returns over time.
- Auction focus: can emphasise capacity, energy output, development of a specific project, land or seabed allocation for project development, or budget allocation.

Several countries have set targets for renewable energy, and auctions are one mechanism to achieve these goals. Successful auction designs therefore take into consideration (in addition to the points raised above) a country's renewable energy targets, the specific characteristics of the technologies involved, and the current macroeconomic environment.

After using a feed-in-tariff programme for more than a decade, China terminated its subsidies for utility-scale solar PV in 2020. Since then, a feed-in-tariff programme still exists, but the renewable-specific rates no longer apply; instead, renewable energy technologies are eligible to receive the coal-fired power price in each market/province for 15-20 years.

In 2023, China introduced nation-wide implementation of its green certificate programme to promote power trading to reduce grid congestion and help several

IEA. CC BY 4.0.

provinces meet their renewable energy targets. Regarding provincial auctions, procurement exercises are carried out for wind equipment, but no data are available on any power purchase auction organised by regional authorities.

In India, in 2023 the government unveiled its ambitious objective to conduct annual auctions for 50 GW of renewable energy capacity. In fact, the country's tender volume more than doubled from 2022 to 2023, with almost 90% of the offered capacity being allocated, reflecting the government's dedication to fostering solar PV and wind technology growth. In contrast, other countries across the Asia-Pacific region displayed the opposite trend. Policy uncertainties were prevalent in multiple nations, resulting in undersubscription in Japan. Moreover, Chinese Taipei and the Philippines did not initiate any new renewable energy auctions during the year.

Meanwhile, two contrasting situations unfolded in Latin America. On the one hand, the region's two largest economies, Brazil and Chile, did not conduct any capacity auctions in 2023. Auctions in Brazil are open according to demand from distribution companies, but in 2023 there was no need to open any public tenders because higher amounts of demand were met through the free market. In Chile, a new auction mechanism will be used in January 2024 because of undersubscription in its 2022 auction. It aims to build a portfolio of projects that could provide power in non-solar hours, includes new incentives for energy storage and non-variable renewables in three geographical zones (north, central and south) and introduces the possibility of transferring system integration costs from the short-term market.

On the other hand, Argentina conducted its first auction since 2018 and allocated the entire targeted volume. Ecuador and Guatemala also had successful renewable energy auctions in 2023.

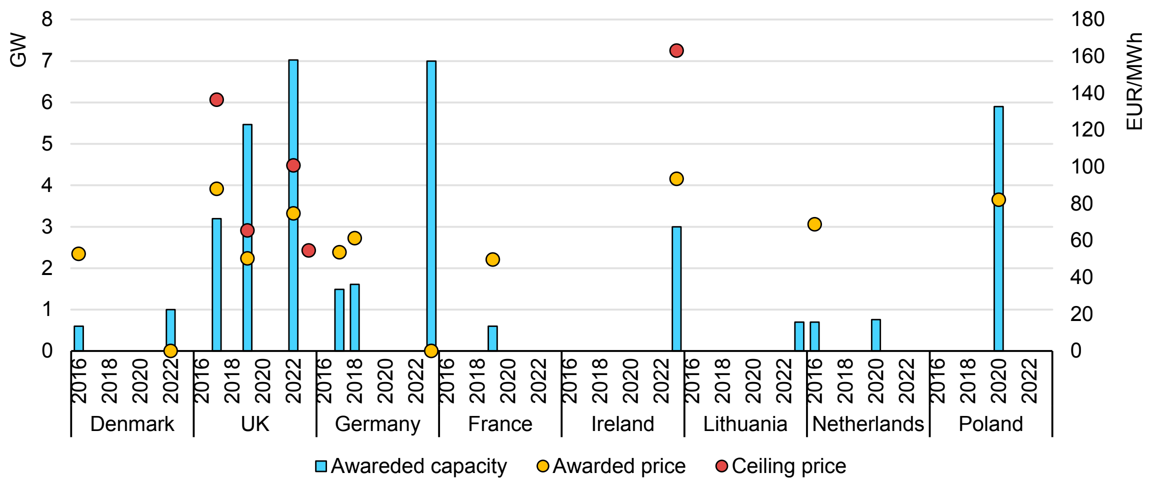
In the Middle East and North Africa region, several countries initiated competitive auctions for renewable energy projects in 2023, including solar PV tenders in Algeria, Israel and Morocco, and the United Arab Emirates increased capacity in its existing projects. However, no auctions were concluded, with just one contract awarded in Saudi Arabia, two years after initial bidding in 2021. Instead, most contracts were signed through unsolicited bilateral agreements. Lengthy processes to select bidders, determine winners and negotiate contracts were common, contributing to project implementation delays.

In 2023, Europe offered 9% more capacity in competitive auction than in 2022, awarding again more than 70% of it, with countries presenting a wide variety of situations across the continent. Awarded utility-scale solar PV decreased by almost one-fifth. On the contrary, both onshore and offshore technologies increased, 25% and 33% respectively.

IEA. CC BY 4.0.

Offshore wind technology has been particularly sensitive to inflation and disruptions in the supply chain, given its dependence on energy-intensive materials and the large size of its plants. Furthermore, the challenges of constructing wind farms in the ocean and connecting them to the power grid introduce an additional layer of complexity. When compared with solar PV and onshore wind, offshore entails a longer installation period and higher expenses, although when this technology participates in auctions, it typically secures significant capacity, surpassing that of other variable energy technologies. However, the dynamics of offshore wind in auctions vary considerably across countries and from one year to the next.

Results of offshore wind auctions in selected European countries



IEA. CC BY 4.0.

In 2023, almost 11 GW of offshore wind capacity were awarded in Europe, with Germany accounting for two-thirds of it. This procurement was the first dynamic bidding process in the country, and after a first round with all bids at zero cents, the tender ended with the developers (two major companies from the oil and gas sector) being required to pay for the seabed – a final combined amount of USD 14 billion that will go to the German government. This negative pricing result raised concerns in the industry, as some fear that these costs will be transferred to the customer.

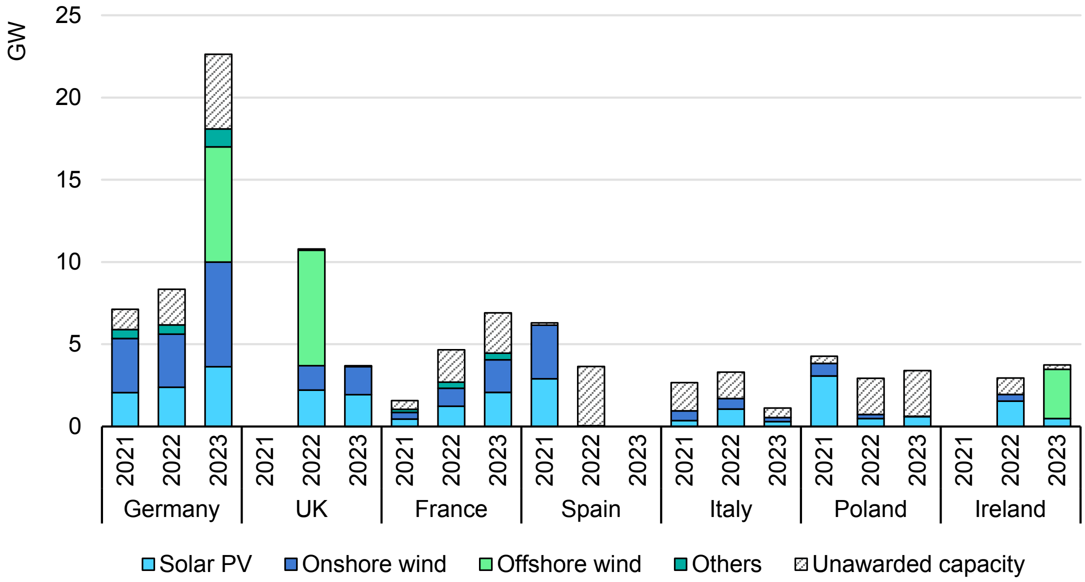
Meanwhile, Ireland held its first offshore wind auction in 2023, awarding all the 3 GW on offer at an average winning bid price of EUR 86/MWh – close to half the tender's ceiling price. Conversely, the United Kingdom had zero bidders for its offshore wind CfD auction following a very successful 2022 allocation, with developers claiming the auction ceiling price was too low relative to cost increases.

In Europe, Germany emerged as the leader for all technologies, setting a record by awarding 18 GW of renewable energy projects through tenders in 2023, almost

IEA. CC BY 4.0.

tripling 2022 results. At the beginning of the year, Germany increased its ceiling prices by 25% for onshore wind and solar PV, and in the auctions held thereafter, the first doubled and the second increased by almost 80%. The offshore wind industry had a successful 7-GW tender, with another of 1.8 GW on the horizon.

Competitive renewable energy auction results in selected European countries



IEA. CC BY 4.0.

In contrast, the United Kingdom awarded only one-third of the previous year's capacity. While there was a slight decrease in PV volumes and a modest gain in onshore wind, the combined total remained on par with 2022 for these two technologies together. Notably, there was a significant absence of bidders for offshore wind projects, as they found the maximum bid prices too low, resulting in no capacity being awarded.

France's first rounds of auctions in 2023 were also strongly under-awarded, with winning projects amounting to only 10% of the more than 2 GW offered. There was no clarity on the financial guarantees required for this procurement round, so most of the bids were rejected. In addition, key material prices had risen in many markets and the ceiling price was not announced. During the rest of the year new tenders were held with various changes, including more clarity on participation requirements and adjusted project indexation (in previous rounds, indexing started on the construction date, and with the new scheme it begins from the award date). These rounds totalling more than 4 GW were much more successful and allocated all targeted onshore wind and utility-scale solar PV capacity (3.4 GW combined), as well as more than 40% of the buildings-integrated solar PV capacity

IEA. CC BY 4.0.

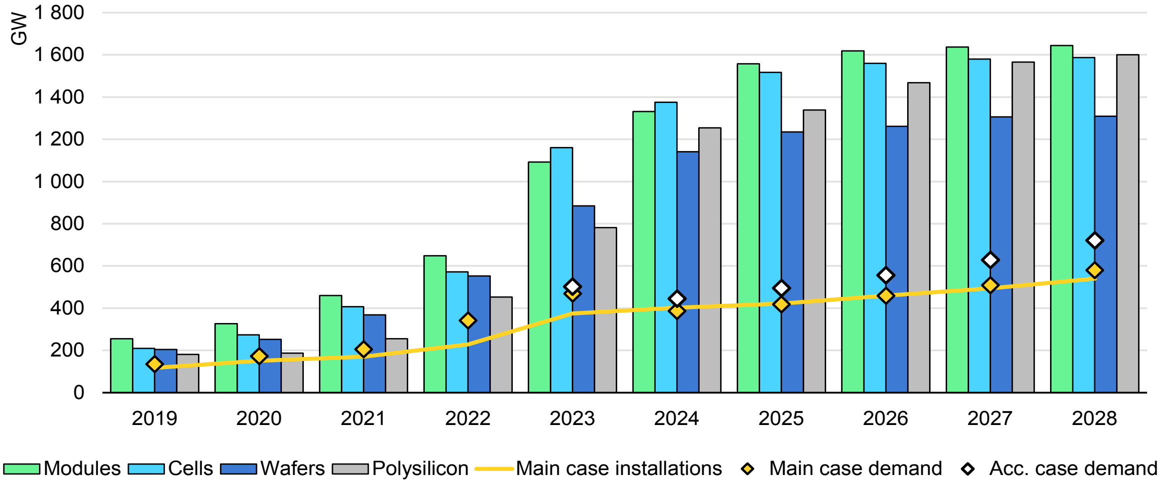
Spain and Greece had previously announced auctions for 2023, but there have been no further updates or announcements regarding these auctions, which are now expected for 2024.

Wind and solar PV manufacturing

PV market oversupply will result in record-low module prices and fierce competition

Global solar PV manufacturing capacity[6] increased by 80% or almost 200 GW in 2022. Plants under construction indicate an increase of 330 GW in 2023 to almost 800 GW – triple the 2021 level. As result, capacity is expected to more than double forecast installations in 2023, pushing the market into a significant supply glut. Based on the manufacturing projects pipeline, it will expand to over 1 100 GW in 2024 and 1 300 GW in 2028, staying at more than double annual PV installations over the forecast period.

Global nameplate PV manufacturing capacity at year-end, annual installations and module demand, 2019-2028



IEA. CC BY 4.0.

Note: Acc. Case = accelerated case.

Sources: IEA analysis based on BNEF; IEA PVPS; SPV Market Research; RTS Corporation; PV InfoLink.

Since 2017, the unavailability of PV-grade polysilicon manufacturing capacity has been the main bottleneck in the PV supply chain. It was especially obvious in 2021, when lagging investments and a fire in one of the largest manufacturing plants led to a global polysilicon shortage and tripling of its price – one of the main reasons for the unprecedented PV module price increase that year.

[6] The least developed part of the supply chain, creating a production bottleneck.

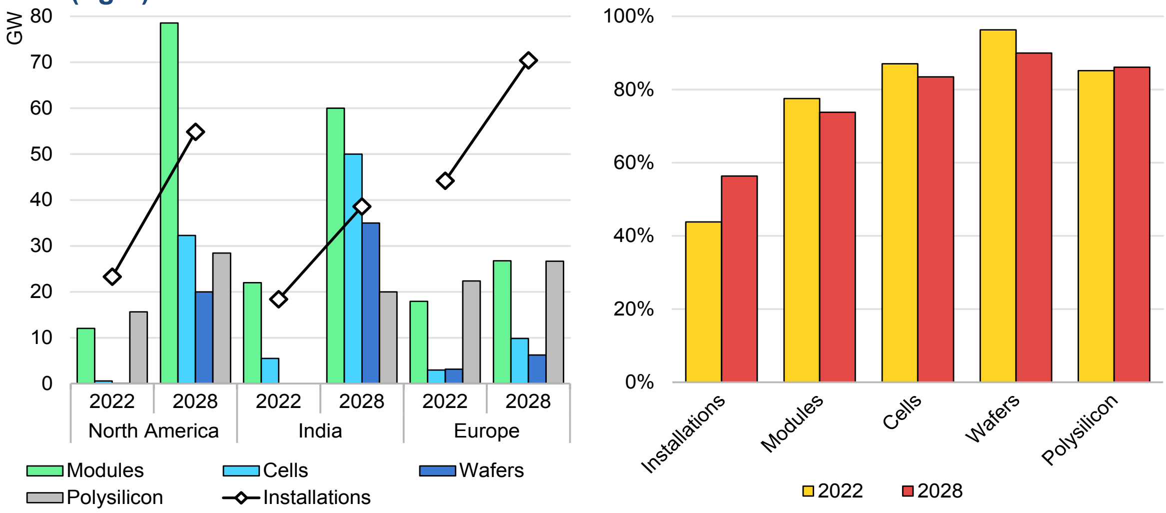
IEA. CC BY 4.0.

However, in 2023 polysilicon production capacity in China will be over three times the 2021 level, putting the global capacity on par with other PV manufacturing segments such as wafers, cells and modules. Wafer manufacturing is expected to be the least developed part of the global supply chain in 2024, although shortages are highly unlikely because capacity will still significantly outweigh expected demand.

Most PV manufacturing capacity expansion to 2028 is expected to take place in China, ranging from 85% for modules to 95% for polysilicon. Chinese companies have expanded their investment plans considerably in the past two years, counting on dynamic global PV demand growth (resulting from energy security concerns since Russia's invasion of Ukraine) and growing clean energy ambitions in an increasing number of countries.

Remaining investments will be split among the United States, India and ASEAN countries. Deployment outside of China is propelled mostly by various dedicated policy measures supporting domestic manufacturing, with the exemption of the ASEAN region, where Chinese companies invest to geographically diversify their production.

Solar PV manufacturing capacity and annual installations in North America, India and Europe, 2022-2028 (left), and China's share in PV production and installations, 2022-2028 (right)



IEA. CC BY 4.0.

Sources: IEA analysis based on BNEF; IEA PVPS; SPV Market Research; RTS Corporation; PV InfoLink.

Many PV manufacturing projects were announced in 2022-2023 outside of China and the ASEAN region, thanks to policy support offered through the IRA in the United States and the Production-Linked Incentive in India. In the United States, roughly half of all projects focus on module assembly only, and the rest are distributed evenly among the other segments.

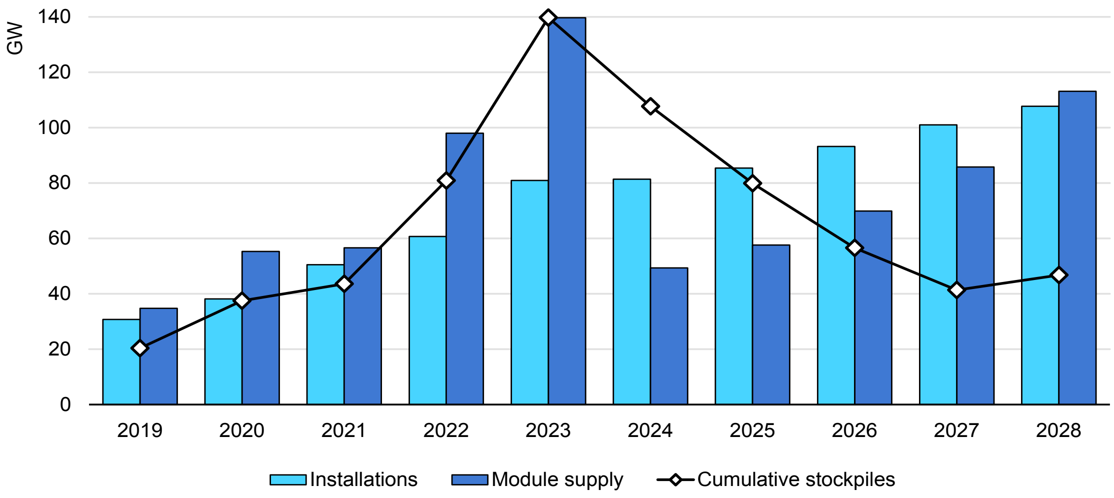
IEA. CC BY 4.0.

As a result of planned investments, PV manufacturing capacity in North America throughout the supply chain is expected to cover about 35% of the region's solar PV demand in 2028. In India, cell and module manufacturing capacity should surpass local demand significantly in 2028, creating export opportunities. However, due to lagging polysilicon investments, the country's PV self-sufficiency will reach only about 50%.

In the European Union, insufficient policy support for domestic PV manufacturers and a lack of demand-side policies promoting the uptake of EU-manufactured products resulted in a limited number of project announcements. Indeed, Türkiye is expected to garner the majority of investments in Europe owing to its local-content incentives and relatively low manufacturing costs. In 2028, despite its growing manufacturing ambitions, Europe is expected to be just 10% self-sufficient and remain the largest PV import market, with China likely being its main supplier.

US and Indian PV manufacturing development plans are unprecedented for these countries and should reduce their PV import dependence considerably. However, global geographical diversification of PV manufacturing is not expected to improve significantly in the forecast period due to China's massive investment plans. Thus, China is still expected to produce 90% of wafers, 85% of polysilicon and cells and 75% of modules in 2028.

US and EU annual PV installations, PV module supplies and cumulative module stockpiles, 2019-2028



IEA. CC BY 4.0.

Sources: IEA analysis based on BNEF; IEA PVPS; SPV Market Research; RTS Corporation; PV InfoLink.

In the European Union in 2022 and 2023 and in the United States in 2023, PV module imports rose significantly more than PV installations. In the European Union, high PV capacity growth expectations and the possibility of import

IEA. CC BY 4.0.

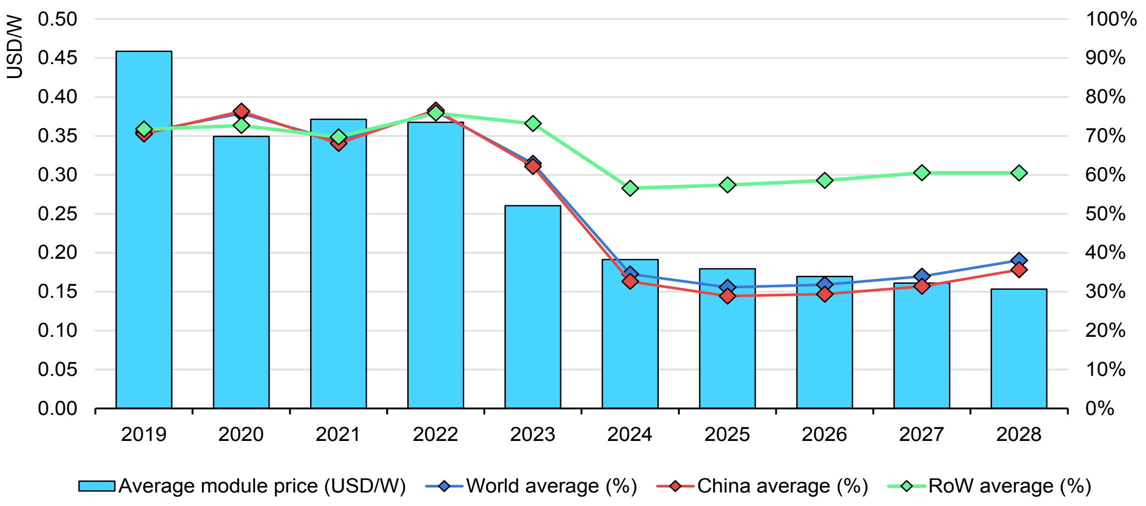
restrictions in the short term have led to considerable stockpiling of modules from China. Distributors are also building up stockpiles in the United States ahead of June 2024, when circumvention tariffs go into effect.

Also contributing to stockpiling is the low-price environment resulting from the supply glut. As a result, module stockpiles at the end of 2023 were an estimated 90 GW in the European Union and 45 GW in the United States, close to double the installations forecast for 2024. However, distributors are expected to start diminishing their stockpiles in 2024 to reduce their storage costs, which should result in lower demand for new modules.

Due to stockpiling in the United States and the European Union, global demand for PV modules was higher than expected based on the deployment forecast, by about 40 GW in 2022 and 80 GW in 2023. This allowed global PV manufacturers to maintain 75% average capacity utilisation in 2022, even with an almost 200 GW increase in nameplate manufacturing capacity.

In 2023, however, this additional demand will not to be enough to offset further supply chain expansion, and the resulting global average utilisation rate likely fell to about 60%. The ongoing oversupply in the solar PV market has also led to fierce competition among manufacturers, resulting in a module spot price drop of roughly 50% between January and December 2023.

Average manufacturing capacity utilisation and global PV module prices, 2019-2028



IEA. CC BY 4.0.

Note: RoW = rest of world.

Sources: IEA analysis based on BNEF; IEA PVPS; SPV Market Research; RTS Corporation; PV InfoLink.

Meanwhile, manufacturers outside of China should be able to maintain higher utilisation rates because they are often protected by various support policies and trade measures. Taking low manufacturing utilisation rates and long-term trends

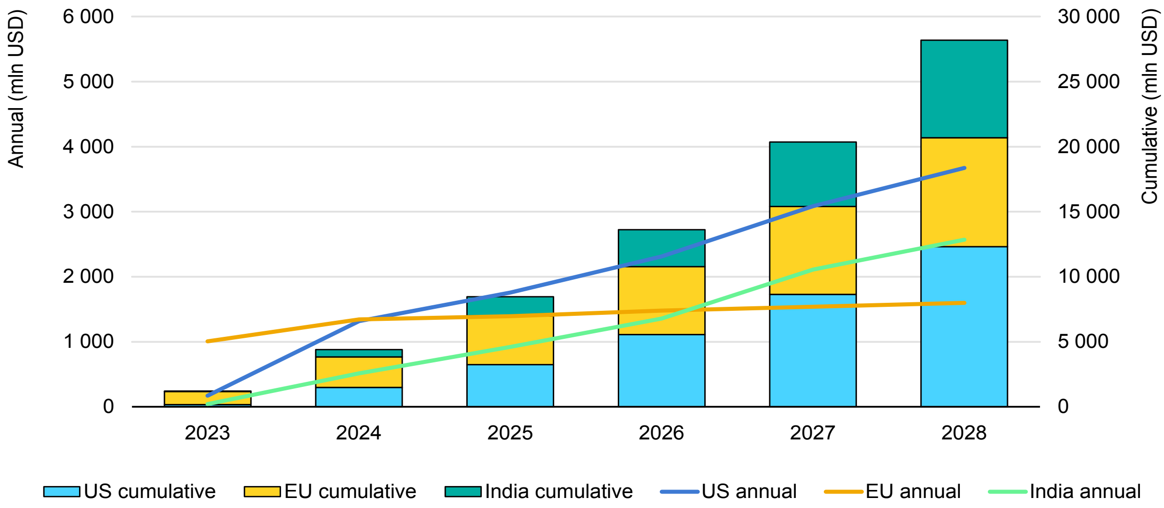
IEA. CC BY 4.0.

in production cost reductions into consideration, PV module prices are expected to continue falling throughout the forecast period.

To survive in such a competitive market, manufacturers are focusing on cost-cutting and innovation. Large, vertically integrated companies will have an advantage, as they are able to control costs across the entire value chain. In terms of innovation, shares of more efficient TOPCon (tunnel oxide passivated contact) solar cell technology are increasing, even though the market is currently dominated by PERC (passivated emitter rear contact) cells. In 2022, about 25% of PV modules produced used TOPCon cells, with the proportion expected to expand further in upcoming years.

In their manufacturing plants in China and ASEAN countries, Chinese companies are leaders in upgrading their manufacturing lines. Nevertheless, manufacturing overcapacity and consequently low PV module prices are expected to increase financial challenges for less efficient manufacturers, in addition to manufacturing project cancellations and overall market consolidation.

PV supply cost increases due to import displacement by domestic US, EU and Indian manufacturing, 2023-2028



IEA. CC BY 4.0.

Sources: IEA analysis based on BNEF; IEA PVPS; SPV Market Research; RTS Corporation; PV InfoLink.

Established Chinese manufacturers (often vertically integrated companies benefiting from various public incentives) are largely responsible for module price drops. Such companies enjoy high production cost efficiencies thanks to the economies of scale they can achieve, which will remain unmatched by any other country in the medium term.

However, many governments, including those of the United States, the European Union, Türkiye and India, have introduced direct subsidies, tax credits, local-

IEA. CC BY 4.0.

content requirements and trade measures to support domestic PV equipment manufacturing. These policies aim to attract manufacturing investment, create jobs and improve clean energy supply chain security.

While solar PV supply chain diversification is needed to dilute overly high concentrations in some areas, it also entails additional costs for governments and consumers. For instance, the cost of manufacturing a PV module from polysilicon to finished panel in 2023, compared to China, was estimated to be about 10% higher in India, 30% higher in the United States and 60% higher in the European Union. These differences result from higher investment, labour and energy costs, as well as lower scales of production and a lack of vertical integration. By 2028, these differences could grow to 70% in India, 100% in the United States and 140% in the European Union.

Thus, the cost to replace Chinese PV imports with more expensive domestic manufacturing over 2023-2028 is expected to reach USD 12 billion in the United States, USD 8 billion in European Union and India. These estimates assume capacity utilisation factors of over 70% for planned manufacturing plants across these countries, which should allow them to operate efficiently. High investment costs notwithstanding, local manufacturing benefits a country's economy in various ways (e.g. by creating employment, spurring innovation and strengthening security of supply), which should also be taken into consideration in policy planning.

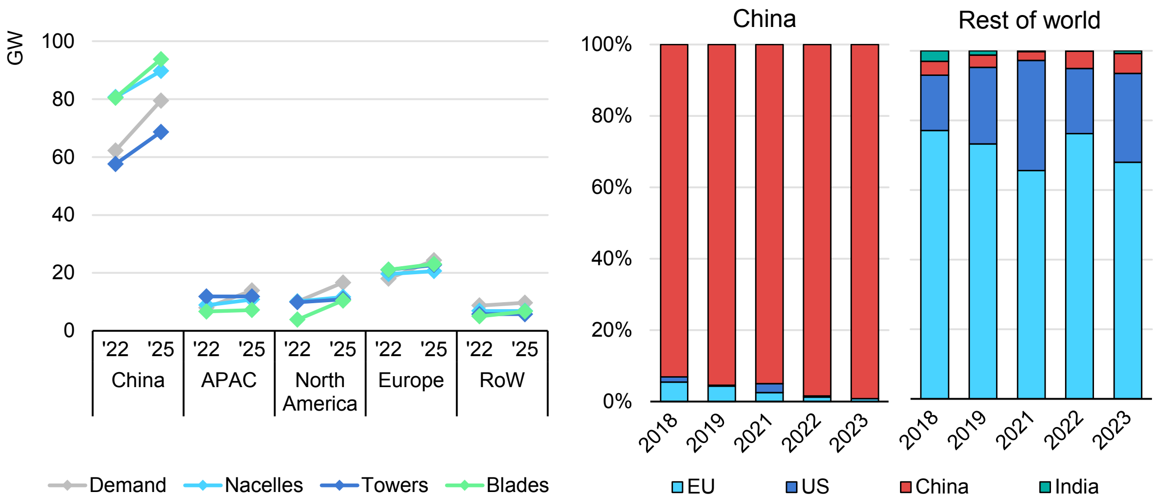
Wind turbine manufacturers outside of China are witholding expansion plans in anticipation of greater policy clarity

In contrast with solar PV, wind supply chain development in the medium term is expected to remain closely aligned with demand. Manufacturing capacity for the main wind turbine components (nacelles, blades and towers) remained mostly unchanged in 2023, at about 110-125 GW per year. Announced expansion projects indicate that by 2025 it will increase to about 120-140 GW, with two-thirds of the expansion happening in China, in line with the country's growing demand.

In China, local OEMs (original equipment manufacturers) supplied over 95% of turbines in the last five years. However, Chinese manufacturers have not yet been able to penetrate markets abroad, where roughly 95% of demand in 2023 was expected to be covered by European and American companies – even though the average price of turbines in China is only one-third of those in Europe and the United States.

IEA. CC BY 4.0.

Wind equipment manufacturing capacity by region and component, 2023-2025 (left), and wind turbine market shares in China and the rest of the world by OEM headquarters, 2018-2023 (right)



IEA. CC BY 4.0.

Note: OEM = original equipment manufacturer. APAC = Asia Pacific. RoW = rest of world.

Sources: IEA analysis based on BNEF; Wood Mackenzie.

Prices of turbines from Chinese manufacturers first began to diverge from those of Western competitors in 2020. First, logistical challenges resulting from lockdowns and other disruptions caused by the Covid-19 pandemic began to inflate EU and US turbine manufacturer costs. Next, raw material and shipping cost inflation in 2021-2022 exacerbated the situation, resulting in an average turbine price increase of 20% per MW between the first halves of 2020 and 2023. In the same period in China, prices decreased more than 50% thanks to local supply chain concentration, dynamic market growth, access to attractively priced raw materials, lower-cost financing and fierce competition among domestic manufacturers.

Western manufacturers thus recorded negative financial results in recent years due to cost inflation, which could not be reflected in equipment selling prices. In addition, technical issues found in one of the leading supplier's turbines (possibly necessitating large-scale repairs) added to the industry's financial strain. Manufacturers are also on the verge of a massive rollout of new-generation offshore wind turbines with a capacity rating of over 10 MW. Most offshore wind farms commissioned after 2023 will use equipment of this size, with 15-MW models already contracted for delivery in 2025.

While wind turbine manufacturers are developing new, larger turbines at a fast pace to stay competitive, switching to a new product always entails increased risk, making companies more cautious about investing. These developments are making OEMs significantly less eager to expand their manufacturing base.

IEA. CC BY 4.0.

Companies are also withholding investment due to uncertainty about demand growth in the core EU and US markets, where persistently long permitting wait times and lengthening grid connection queues hinder faster wind capacity deployment. Recent offshore wind project cancellations in the United States and the United Kingdom are an indication of perceived investment risk. Consequently, nacelle manufacturing capacity in Europe and the United States is expected to increase just 3 GW by 2025.

However, the manufacturing outlook should improve in the longer term as future wind demand growth becomes more certain, including because of the US Inflation Reduction Act and the newly announced EU Wind Power Action Plan. Announced by the European Commission in October 2023, the Wind Power Action Plan aims to accelerate installation growth and support local manufacturers by streamlining permitting, improving auction design, facilitating access to financing and expanding workforce training programmes.

Proposed auction improvements include providing long-term volume visibility and introducing qualitative criteria and inflation compensation mechanisms. Governments are also supposed to better help manufacturers access non-EU markets and secure critical mineral supplies through trade agreements and ensure equality with foreign competitors. Although implementation is planned for 2024, the broader impacts of these policies on wind manufacturing capacity will not be visible until after 2025.

Grid connection queues

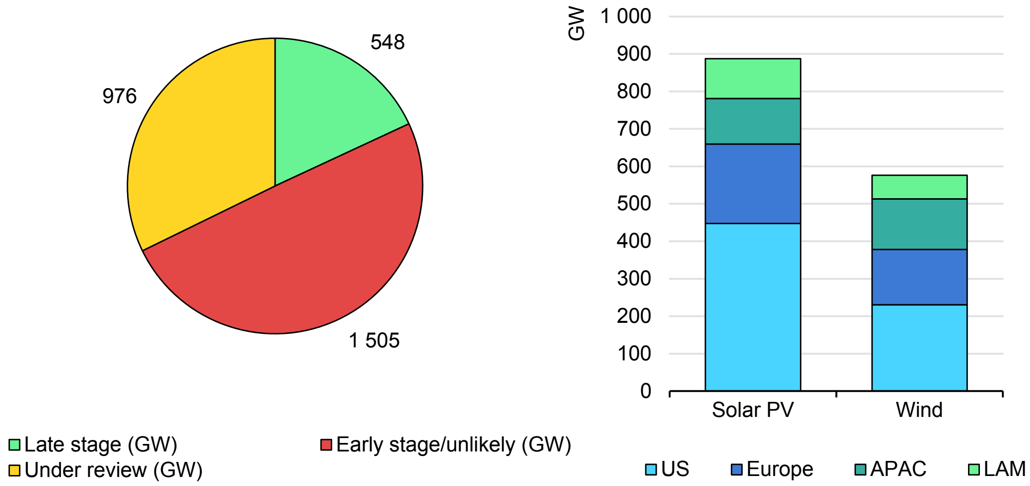
Grid queues are growing and investment is lagging, leading to longer lead times and higher costs

Policy support and lower costs have considerably enlarged the project pipeline worldwide, resulting in longer connection queues. Currently, over 3 000 GW of renewable energy projects are in connection queues globally, with nearly 1 500 GW of wind and solar PV projects in advanced stages of development – enough to nearly double current installed global capacity for these technologies.

However, grid investment has not kept pace with renewable energy development: outside of China and India, transmission and distribution investments have grown just 1% per year since 2010. Thus, lower-than-needed grid investments, coupled with low barriers to queue entry, have led to increases in both connection costs and project lead times, putting economic pressure on developers and causing project delays and cancellations.

IEA. CC BY 4.0.

Renewable energy capacity in connection queues by project stage (left), and advanced-stage solar PV and wind projects by region (right)



IEA. CC BY 4.0.

Notes: APAC = Asia Pacific. LAM = Latin America. All capacity presented is sourced from publicly available country-level connection queue information. US data 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 from Red Eléctrica de Espana. Japan data 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 from ANEEL. Italy data from TERNA. UK data from Ofgem. Germany data from Bundesnetzagentur. Australia data from AEMO. Mexico data from CENACE. Chile data from CEN. Colombia data from UPME. India data estimated based on CEA transmission buildout planning. Solar PV values are a mix of AC and DC, depending on the source.

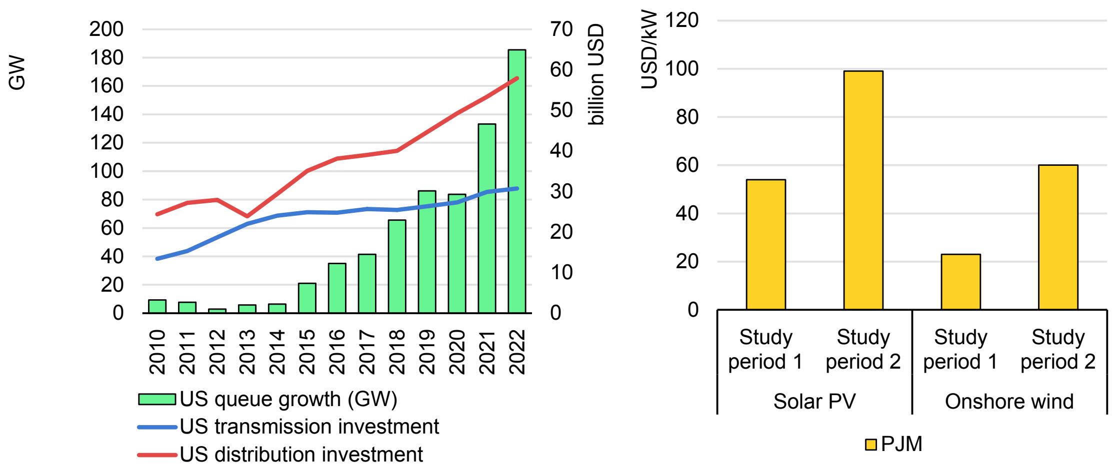
Since 2010, entries into interconnection queues across the United States have increased by at least 20 times, while investment in transmission and distribution grids has only doubled. In France, the amount of solar PV and onshore wind capacity waiting for connection has nearly doubled since 2018, and new applications for connection in the United Kingdom have risen 80% since 2022.

The increase in connection requests has lengthened project lead times. In the United States, average queue lead times rose from three years in 2015 to five years in 2022, while in the United Kingdom 120 GW of projects awaiting connection have been offered connection in 2030 or later. Meanwhile, France's backlog of projects has led to connection delays of 22 months. In Brazil, increased development of solar PV and onshore wind has increased grid connection queues

IEA. CC BY 4.0.

and project lead-times. Even projects nearing completion can still be subject to delays: In Australia for instance, commissioning processes can be a year or longer.

United States connection queue growth and grid investment (left), and wind and solar PV connection cost increases (right)



IEA. CC BY 4.0.

Notes: "Study period 1" covers projects with completed interconnection studies from 2000-2016; "study period 2" covers projects with completed interconnection studies from 2017-2022.

Sources: (left) IEA analysis and IEA (2023), World Energy Investment 2023; (right) IEA analysis based on Lawrence Berkeley National Lab Interconnection Cost Analysis in the PJM Territory.

In addition to longer wait times, projects are also facing higher grid connection costs. In the United States, for projects with completed interconnection studies in the PJM interconnection region, costs for interconnection doubled from USD 42/kW before 2020 to USD 84/kW after, and these potential costs are even higher for onshore wind (USD 136/kW) and solar PV (USD 253/kW). In the NYISO region, costs for interconnection have doubled since 2017, primarily due to the need for network upgrades.

Additionally, in many markets, connection costs are shared among developers, utilities and consumers. In France, for example, developers or consumers installing renewable capacity are responsible for 40-100% of the connection costs, with increased costs potentially impacting development.

Long grid connection queues and inadequate investment could slow wind and solar PV development growth. Investments in grids must double to over USD 600 billion per year by 2030 to meet climate targets, while queues need to be reformed to address long lead times and project speculation.

Policies are already being deployed to resolve both concerns. In 2023, Brazil held auctions for six new transmission lines connecting resource-rich areas to demand centres, while to shorten connection queue backlogs in the United States, the

IEA. CC BY 4.0.

Federal Energy Regulatory Commission proposed new guidelines to prioritise study processes and reduce speculative connection requests. In addition, the European Union's action plan for grids will include measures to reinforce and expand grids more quickly. These policy efforts will be critical for countries to achieve their climate targets.

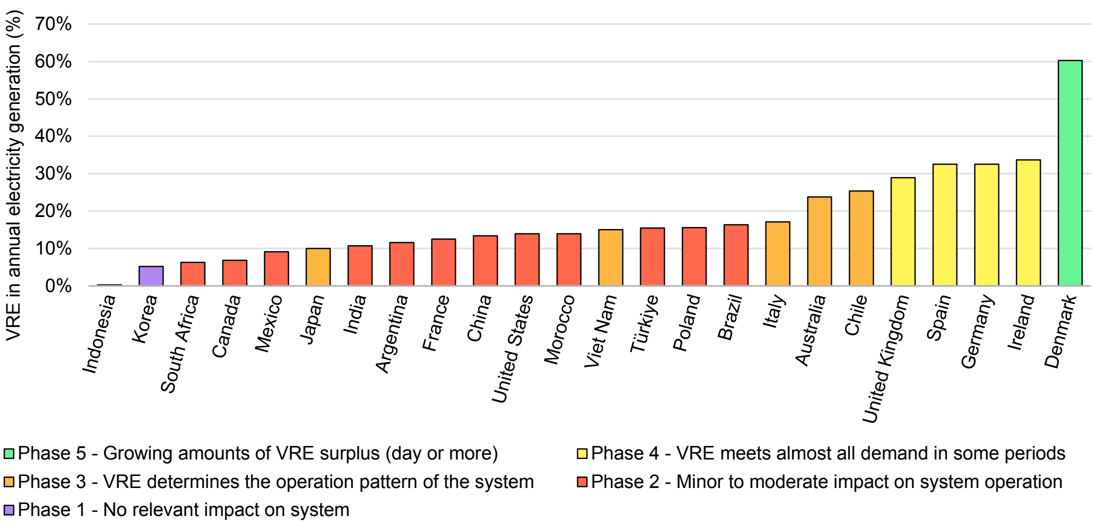
Renewable energy integration

Integrating higher VRE shares will have implications for power systems globally

The share of wind and solar PV generation increased from 7% in 2018 to an estimated 13% in 2023. Over the next five years, potential VRE generation is forecast to double again to 25% in 2028 owing to accelerated wind and solar PV capacity growth. This rapid expansion in the next five years will have implications in power systems worldwide.

The IEA categorises VRE integration into six phases based on the challenges power systems face with increasing VRE shares. Currently, most power systems fall into Phase 1, wherein VRE has no significant impact at the system level. However, an increasing number of regions are entering higher phases, and Denmark has reached Phase 5, with growing amounts of VRE surplus.

Countries in phases of renewables integration, 2022



IEA. CC BY 4.0.

Note: Capacity additions refer to net additions.

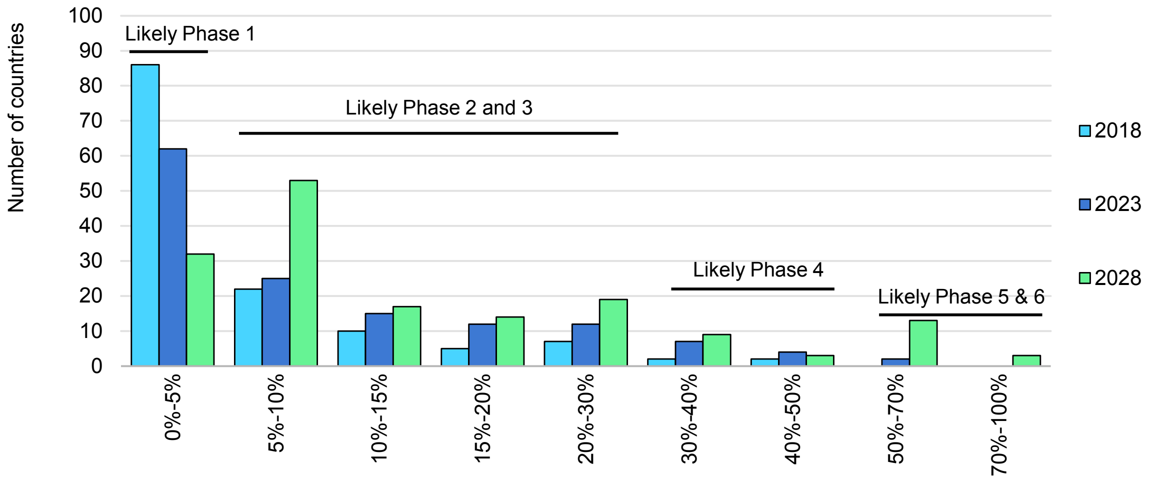
By 2028, there will be more countries with VRE shares of 5-15% than below 5% for the first time. As VRE starts to contribute at these higher shares, it is likely that many of these countries will reach the phase-2 stage and begin to experience

IEA. CC BY 4.0.

minor to moderate impacts of VRE penetration in their systems. However, the specific phase classification of each country will depend on the relative share of wind and solar PV, their complementarity to one another, and the correlation between VRE production and electricity demand. Countries in phase 2, will have to use existing flexibility sources more effectively to integrate wind and solar PV power cost-effectively.

In the next five years, around 30 countries are forecast to have VRE penetration of 15-30%, not only in Europe and the United States but also in large emerging economies, including China, Brazil, India and Türkiye. They will likely begin to experience greater net load variability and changes in power flow patterns, with VRE increasingly determining how the system operates. These countries may also be subject to subregional challenges depending on their interconnection capacities with other grid areas. For instance, accelerating wind and solar PV deployment in China's Northern and Northeastern regions could result in rising curtailment through 2028 – despite recent investments in grid infrastructure – due to the high concentration of VRE capacity in these grid areas.

Number of countries by potential range of VRE share in annual electricity generation.



IEA. CC BY 4.0.

Note: Capacity additions refer to net additions.

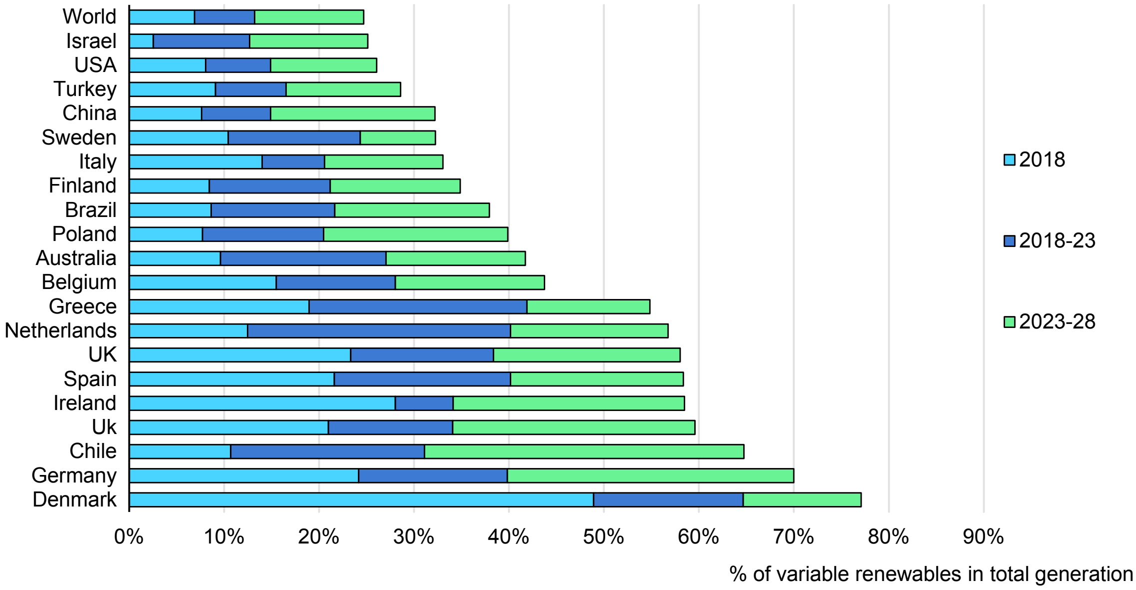
In the European Union, potential VRE penetration in 2028 is expected to reach more than 50% in nine countries, with over 90% of Denmark's power generation forecast to come from wind and solar PV systems. These countries will likely be in phase 5 or 6, with VRE making up almost all generation in some periods while also producing growing amounts of surplus.

Although EU market interconnections help integrate solar PV and wind generation, grid bottlenecks will increasingly pose challenges and lead to curtailment. For instance, VRE shares are expected to reach almost 65% in Spain and over 70%

IEA. CC BY 4.0.

in Portugal by 2028. While the Iberian Peninsula is well interconnected, Spain's connections with France are currently limited. In 2023, the curtailment of PV and wind generation in Spain more than tripled from 2022 for economic reasons (i.e. because of low prices). Curtailment is also expected increase in Germany, Ireland, the United Kingdom and Greece because grid expansion cannot keep pace with variable renewable energy growth.

Shares of potential variable electricity generation for selected countries above global average in 2028



IEA. CC BY 4.0.

Note: Capacity additions refer to net additions.

More storage systems are crucial for integrating higher VRE generation

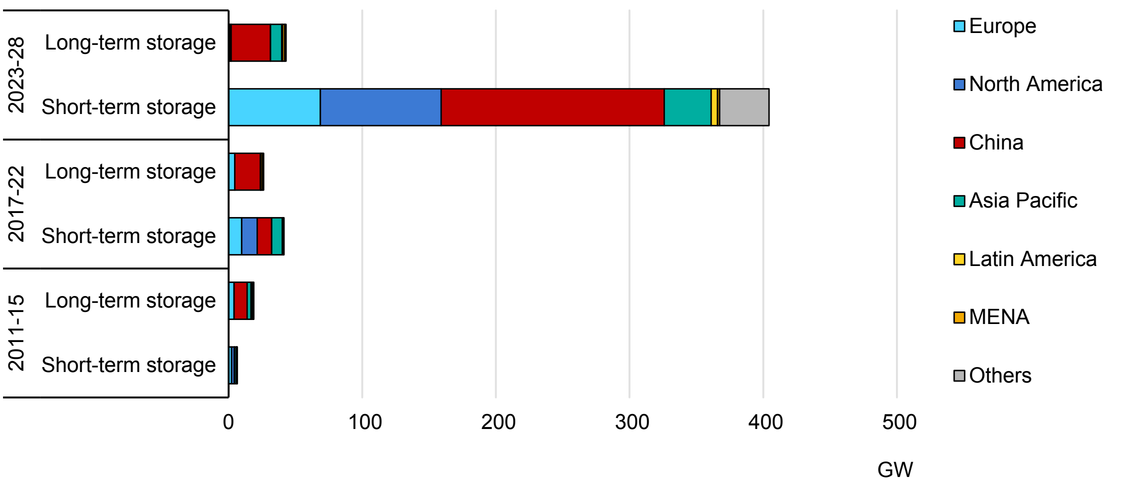
Electricity storage solutions can ameliorate the grid integration challenges that come with rising VRE shares, especially in countries with high wind and solar PV penetration. Today, two complementary technologies are able to cost-effectively provide storage: stationary batteries for 1-4 hours, and pumped-storage hydropower plants for 4-15 hours, depending on the reservoir size. Support policies and falling stationary battery costs over the last decade have stimulated investment in the past five years in Europe, the United States, China and Australia, where regional-level grid bottlenecks are making short-term storage necessary to provide electricity security in countries with limited wholesale electricity markets and balancing and ancillary services in liberalised power markets.

Stationary batteries in Europe, the United States and Australia can tap into balancing markets through arbitrage opportunities at peak hours. Over the forecast period, rising VRE deployment is expected to accelerate the installation

IEA. CC BY 4.0.

of storage systems, with over 400 GW to be deployed between 2023 and 2028. China, the United States, the European Union and India lead this expansion.

Short- and long-term storage capacity growth, 2011-2028



IEA. CC BY 4.0.

Notes: MENA = Middle East and North Africa. Short-term storage refers to stationary batteries providing 1-4 hours of storage. Long-term storage includes pumped-storage hydropower and concentrated solar plants with long-term storage capabilities.

Source: IEA (2023), World Energy Outlook 2023.

For long-term storage, deployment remains limited compared with stationary batteries, especially where it is most needed in markets with VRE shares forecast to reach over 50% in 2028. Challenges include lengthy development and permitting timelines, a lack of incentives and incompatible market designs that often do not support the business case for pumped storage plants in advanced economies, as well as limited or exhausted natural resources in some areas.

While existing long-term storage capabilities in Europe, the United States and Japan will contribute to system integration, long-term storage needs are increasing rapidly, so investment decisions must be made today for plants that will be required 6-10 years from now. While long-term storage is considered a strategic grid asset for electricity security in an increasing number of countries, pumped-storage hydropower deployment is expected to take place mostly in China, thanks to strong and consistent public support facilitating investment. .

Policy measures are needed to meet rising VRE curtailment challenges

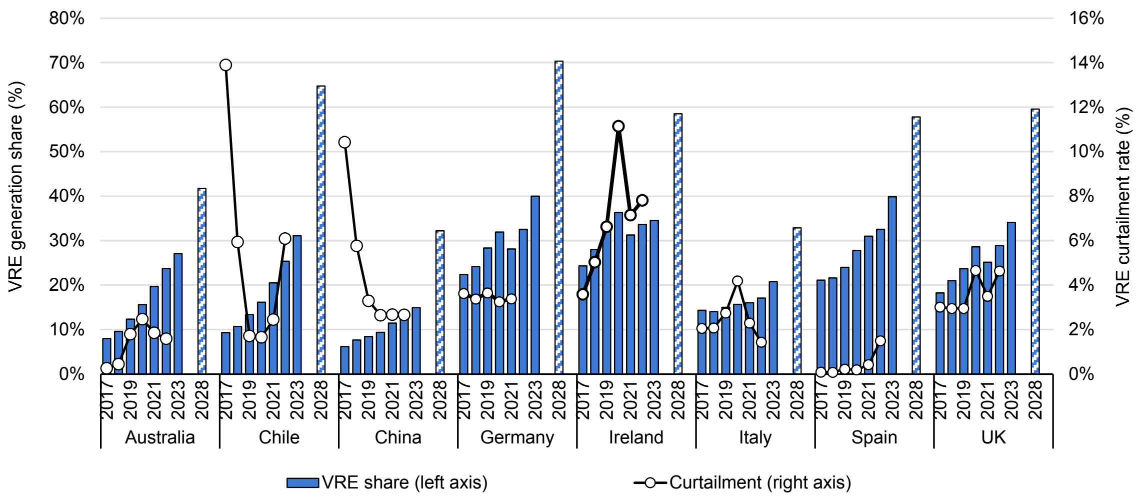
As VRE uptake continues to grow, the share of curtailed wind and solar PV generation is also on the rise in numerous markets. However, while VRE curtailment is rising overall in an increasing number of countries, the percentage

IEA. CC BY 4.0.

of wind and solar PV generation going unused remains relatively low, typically ranging from 1.5% to 4% in most major renewable energy markets.

Naturally, curtailment rates are higher in regions that need substantial grid infrastructure expansion to connect renewable energy installations to consumption centres. Effective system planning is thus crucial for well-integrated wind and solar PV growth and should encompass considerations such as the regional distribution of generation and the development of policies to encourage system flexibility. Additionally, power markets must evolve beyond the traditional design and regulation models to create a more accommodating environment for higher renewable energy integration.

VRE generation shares and technical curtailment rates for selected counties



IEA. CC BY 4.0.

Notes: Data points represent officially reported curtailed or constrained energy and combine various schemes, depending on the country. VRE refers to solar PV and wind unless otherwise specified. Italy includes only wind. Spain includes PV, wind, CSP and biomass technologies. The United Kingdom includes only wind. “Technical curtailment” refers to the dispatch-down of renewable energy for network or system reasons. Dispatched-down energy due to economic or market conditions is not included.

Sources: IEA analysis based on 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 2000-2021; 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).

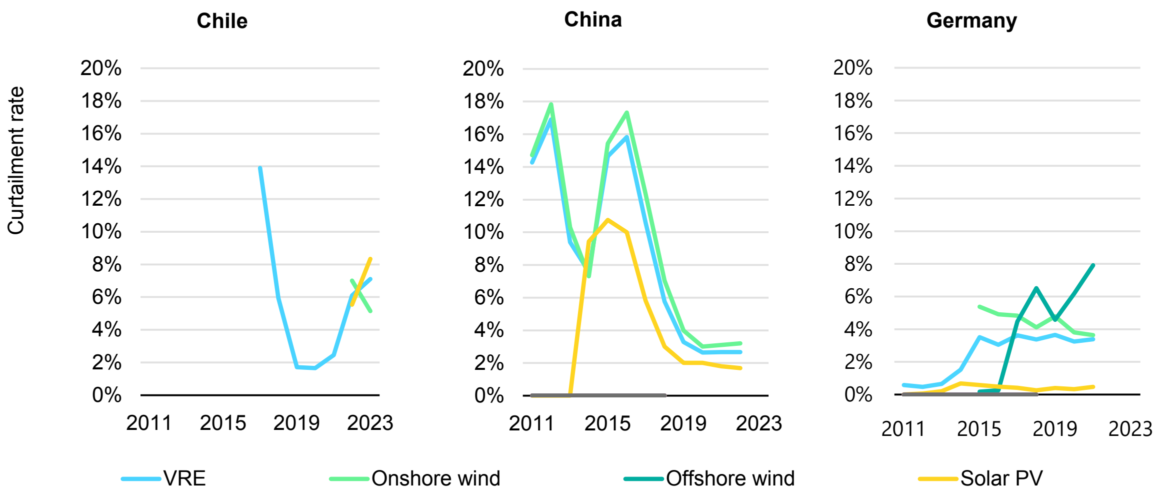
The impact of curtailment on energy technologies is contingent on various factors and scenarios. Plant size determines whether the connection is to transmission or distribution lines, which normally have different congestion levels. Also related to congestion, the distribution of resources (e.g. widespread solar radiation and

IEA. CC BY 4.0.

discreet high-wind-resource locations) helps determine plant concentrations for each technology, alleviating higher congestion levels at certain nodes.

Hourly generation profiles are a critical factor, especially in the absence of storage, as energy production can sometimes surpass demand. From the perspective of transmission system operators (TSOs), a system's load profile is key and can be influenced by a high penetration of distributed generation. Distributed PV in particular has the potential to reduce demand during specific hours, thereby intensifying the mismatch between generation and demand.

Technical curtailment rates per technology for selected countries



IEA. CC BY 4.0.

Notes : VRE = variable renewable energy. The 2023 curtailment rate for Chile in 2023 comprises the period from January to September. Data points represent officially reported curtailed or constrained energy and combine various schemes, depending on the country. VRE refers to solar PV and wind unless otherwise specified. "Technical curtailment" refers to the dispatch-down of renewable energy for network or system reasons. Dispatched-down energy due to economic or market conditions is not included.

Sources: IEA analysis based on 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 2000-2021; Bundesnetzagentur, Monitoring Report 2022.

Over the past ten years, wind energy has consistently constituted the largest portion of curtailed VRE in China, accounting for 75-85% of total annual curtailment. However, the curtailment rate for wind peaked at 17% in 2016 and it has fallen steadily since then to around 3% in 2022. Solar PV expansion in China has been rapid and is anticipated to continue. Its curtailment rates have been lower than for wind-based generation, reaching a peak of 11% and subsequently decreasing to less than 2%.

China's substantial annual investments of approximately USD 75 billion in grid infrastructure since 2010 have been pivotal in reducing VRE curtailment. Adjustments to the feed-in-tariff scheme (to provide stronger incentives in provinces with limited system integration challenges) have also contributed to this positive trend.

IEA. CC BY 4.0.

In Germany, VRE curtailment rose at the beginning of the last decade. While major grid investment decisions to strengthen the north-south corridor are still pending, Germany has implemented smaller-scale grid expansions that have stabilised the trend from 2015. Wind is the most curtailed energy source, with onshore wind accounting for 60% of curtailed energy, while solar PV makes up less than 5% annually.

Onshore wind curtailment has been trending downwards since 2020, thanks to network expansion projects in Schleswig-Holstein. However, offshore wind curtailment has had both absolute increases, corresponding to new commissioned capacity, and a rise in curtailment rates from negligible in 2015 to 8% in 2021, with further increases expected for 2023. Meanwhile, repercussions of onshore wind bottlenecks in northwestern Germany are also being felt in the offshore wind sector, reflecting the interconnectedness of renewable energy challenges.

In Chile, high curtailment rates result from a rapid increase in VRE generation, a geographical mismatch between renewable generation and energy demand, and insufficient deployment of the transmission grid to keep pace with these developments. The merger of Chile's central and northern electricity systems in 2017 initially reduced curtailment from 14% to 2%, but this positive trend was not sustained, causing VRE curtailment to rise to 6% in 2022. Solar PV plants were primarily affected, with their curtailment reaching 13% in October 2022 and 14% in November, coinciding with peak solar irradiation.

Anticipating record levels, Chile's energy curtailment in the first three quarters of 2023 already matched the total for 2022. In the last quarter, which registered the highest solar radiation and completion of the year's capacity additions, curtailment was equivalent to almost half of total curtailed generation in 2022. Comparing the first three quarters of 2023 with the same period in 2022, wind curtailment had increased 20%, with an average monthly curtailment rate of 5% – one point higher than in 2022. Meanwhile, solar PV generation was curtailed at an even higher rate, with 1 TWh dispatched down in the first three quarters of 2023, 2.4 times the amount in the same period in 2022. Solar PV curtailment rates also rose to a 8% monthly average in this period of 2023, peaking at 18% in September 2023.

Financial performance

Growing macroeconomc challenges for renewable energy equipment manufacturers and project developers test their financial health

The renewable energy industry has shown strong financial resilience in the face of multiple challenges such as volatile commodity prices, supply chain constraints and trade restrictions. While growing demand, continuous government support and positive outlooks for solar PV and wind have made renewable energy

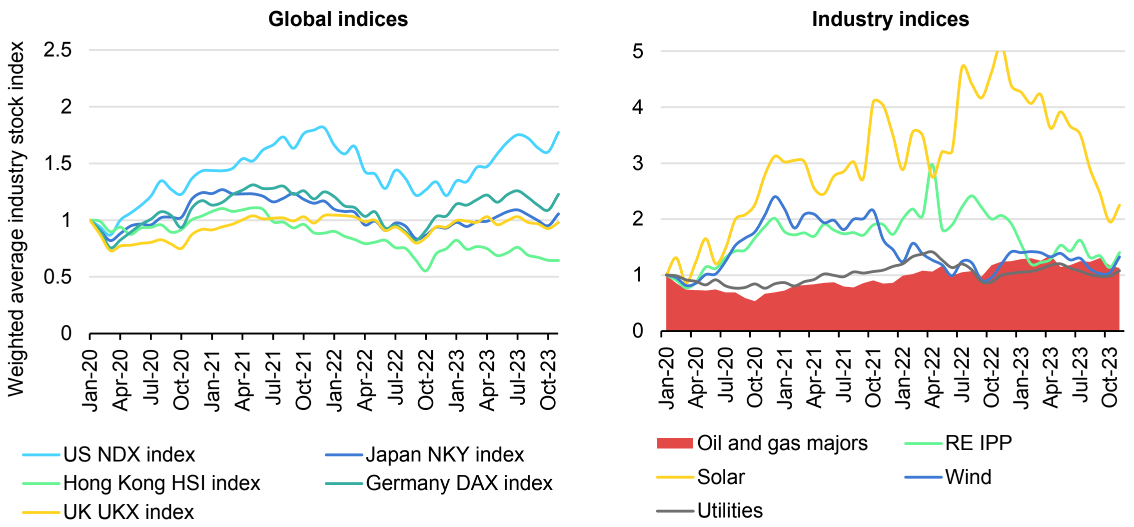
IEA. CC BY 4.0.

companies attractive to investors, the ongoing energy crisis and current macroeconomic environment are testing their financial resilience yet again.

Before the onset of the Covid-19 pandemic, the renewable energy industry (specifically solar, wind and renewable energy IPPs) had been outperforming in most major market indices, and the broader energy sector in equity markets. However, during the first half of 2020, wind turbine and solar PV equipment manufacturers experienced negative EBITDA (earnings before interest, taxes, depreciation, and amortisation) due to temporary revenue declines caused by the pandemic's impact. Remarkably, renewable energy companies recovered rapidly from the Covid-19 crisis and demonstrated financial resilience to the end of 2022.

In 2021, rising commodity prices increased manufacturing costs for solar PV modules and wind turbines. Then, in 2022, Russia's invasion of Ukraine triggered a global energy crisis, leading to further cost increases for inputs such as electricity, raw materials and transportation, along with elevated interest rates and persistent supply chain disruptions.

Indexed stock market prices for global indices and traded energy companies, 2020-2023



IEA. CC BY 4.0.

Notes: RE IPP = renewable energy independent power producer.

Solar companies (17): 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.

Wind (10): 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.

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 (16) : Enel SpA ; Iberdrola SA ; Electricite de France SA ; E.ON SE ; EDP ; Engie ; SSE PLC ; Drax Group PLC ; ACS

Actividades de 84onstrucción y Servicios; Tata Power; RWE AG; AES Corporation; Duke Energy Corporation; Sempra Energy; National Grid PLC; Xcel Energy Inc.

Source: IEA analysis based on Bloomberg LP (2023), Markets: Stocks (database).

IEA. CC BY 4.0.

During the second half of 2022, the IEA's solar PV manufacturers and independent renewable energy developers (RE IPP) index was outperforming major indices. However, since the beginning of 2023, global equity markets have been picking up while the opposite holds true for the renewable energy industry. For instance, solar PV manufacturing companies lost more than half of their market value from January to October 2023, while the stock market value of RE IPPs and wind industry declined by over 25%. Wind and RE IPP indexes rebounded in November, however still remained 5-10% below the January levels.

Renewable energy IPPs showed strong financial performance in 2022 owing to the stable revenue streams they received from existing projects with long-term (10-25 year) fixed-price contracts. In Europe, many RE IPPs and major utilities reported significantly higher earnings throughout 2022 than in 2021 due to higher revenues from electricity prices. This also led many companies in this energy subsector to secure higher profits in 2022 using hedging strategies and long-term contracts.

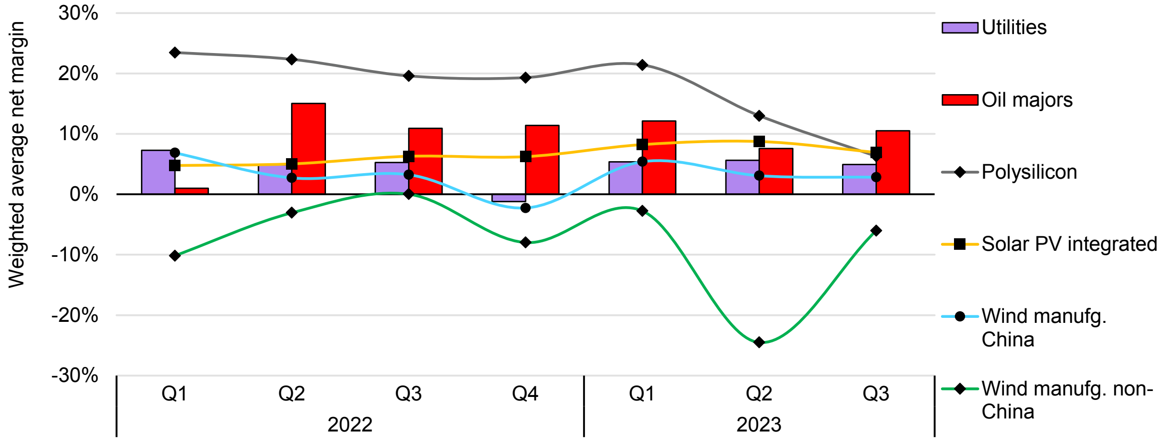
In contrast, in 2023 the same companies faced challenges such as a higher cost of debt, grid infrastructure inadequacy and integration difficulties, and longer lead times. For these reasons, investors are increasingly limiting investments to mainly low-risk projects that have secured either permitting or an interconnection agreement. These overall conservative investor sentiments, high interest rates and higher costs have caused sharp drops in the indices for RE IPPs. As for utilities included in our categorisation, 2023 was a steady year following the trend prior to the Covid-19 pandemic.

Solar PV market challenges emerge due to fierce competition, impending overcapacity and supply gluts

The solar PV industry demonstrated remarkable financial resilience by maintaining stable profits throughout 2022, largely owing to the increased market share of integrated Chinese companies (ranging from 50% to 80% across the value chain) and their effective cost-saving strategies.

IEA. CC BY 4.0.

Weighted average net margins of renewable energy companies, large utilities and oil majors, 2022 and 2023 (Q1, Q2 and Q3)



IEA. CC BY 4.0.

Note: Wind manufg. = wind equipment manufacturing companies.

Source: IEA analysis based on companies' annual and quarterly financial reports

However, an extensive supply glut due to manufacturing capacity expansion within and outside of China is reducing the profitability of all companies throughout the supply chain. Fierce competition is cutting the profits of vertically integrated manufacturers, while non-integrated firms may struggle to attain any profitability at all. This heavy price competition is likely to intensify in the near future, with small manufacturers struggling financially due their higher prices compared to larger company products.

Around 30 GW of polysilicon, 60 GW of wafers, 80 GW of cells and 100 GW of PV modules manufacturing capacity is currently under development outside of China, and the majority of these new investments are in countries with trade measures against China. While these measures can help local manufacturers complete their projects, making these new facilities profitable could be quite challenging in the long term.

As for the polysilicon industry, rising PV demand and limited polysilicon capacity availability raised polysilicon prices significantly to USD 40/kg in November 2022, which benefited both manufacturers and producers by increasing their net margins, as their costs did not rise proportionally. This trend was transitory, however, as global polysilicon capacity almost doubled in 2023 (to 800 GW) and its price plummeted to USD 10/kg. Historically, such imbalances between supply and demand have led to negative margins, signs of which were evident in Q3 2023. This has caused many Chinese companies to either stall their plans for new factories or even suspend operations due to losses from high production costs.

IEA. CC BY 4.0.

The wind industry is facing prolonged struggles amid financial challenges

Wind system manufacturers in Europe and the United States have posted negative net margins for seven consecutive quarters over the last two years. Multiple obstacles are responsible for their financial underperformance. First, volatile demand is causing manufacturing facilities to operate at less than full capacity. Limited access to raw materials, rising macroeconomic challenges, fluctuating commodity prices, higher interest rates and restricted access to financing have impacted their profitability. For instance, US offshore wind developers are cancelling agreements, delaying projects or requesting price renegotiations because current project economics do not allow them to meet rising interest rates and increased commodity costs. In Europe, negative bidding in some offshore wind auctions (and the resulting uncertainty regarding economic viability) is also challenging project completion, thereby affecting overall project economics.

In response to these challenges, the European Commission launched its Wind Power Action Plan in October 2023 to make European wind system manufacturing more competitive. The Wind Power Action Plan places strong emphasis on enhancing auction design by implementing prequalification and non-price criteria for wind energy projects and encouraging member states to index their auction prices and tariffs.

It also intends to boost investment in clean technology manufacturing by doubling funding from the EU Innovation Fund to EUR 1.4 billion and involves the European Investment Bank (EIB) in mitigating risks for private banks lending to the wind industry. Additionally, the plan aims to improve transparency in wind energy deployment, streamline permitting processes through digital tools, and employ trade measures to ensure fair competition in the industry.

In contrast, Chinese wind turbine manufacturers have experienced less disruption from commodity price fluctuations, with strong domestic demand bolstering their financial stability. Their resilience results partly from vertically integrated large Chinese wind equipment manufacturers also serving as significant project developers, allowing them better control over project costs and the ability to absorb price shocks more effectively. For instance, in a major Chinese wind company's financial statement for the first half of 2023, wind farm development was the most profitable business segment and manufacturing was the least. In addition, fierce local competition in China is pushing local turbine prices down, resulting in low profit margins despite persistently high commodity prices.

IEA. CC BY 4.0.

Renewable capacity for hydrogen

Renewable power capacity dedicated to hydrogen and hydrogen-based fuel production is forecast to grow 45 GW between 2023 and 2028, roughly equal to Sweden's total installed electricity generation capacity. Growth is led by China, followed by Saudi Arabia, and the United States. These three markets account for more than 75% of renewable capacity for hydrogen production by 2028.

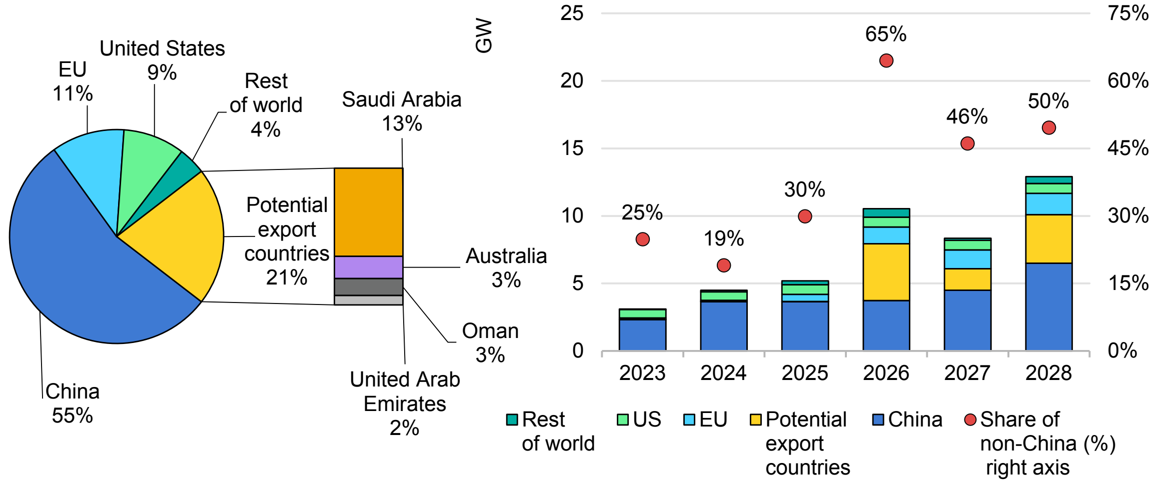
Globally, this growth makes up around 1% of total renewable energy capacity deployment in 2023-2028. However, hydrogen plays a larger role in total solar and wind investments in individual markets focused on exporting it – from 4% in Australia to over 30% in Oman. By 2028, potential export countries could account for over one-fifth of hydrogen-driven renewable capacity deployment, led by Saudi Arabia, Australia, Oman and the United Arab Emirates. With the prospect of producing economically attractive renewable hydrogen to ship to potential demand centres in Europe and Asia, these countries aim to become major exporters of renewable hydrogen and hydrogen-based fuels.

While good solar and wind resources, land availability and location along existing shipping routes strengthen the business case for hydrogen production in these countries, government support is also crucial to develop projects in these markets. For example, Saudi Arabia's 2-GW Neom electrolyser project is partially owned by the state and has received funding from the National Development Fund and Saudi Industrial Development Fund. In Oman, the government is offering land leases at a reduced cost through auctions, while Australia is providing more than AUS 500 million in grants to develop hydrogen hubs and AUD 2 billion under its Hydrogen Headstart program which provides revenue support for projects through competitive hydrogen production contracts.

However, the development of an international hydrogen market is a key uncertainty affecting the forecast, particularly in markets that have limited domestic demand for hydrogen. Foreign offtakers still need to be secured for projects under development and certification schemes still need to be developed to demonstrate regulatory compliance with importers. Additional forecast uncertainties include a lack of clarity on definitions for low-emission hydrogen, and whether infrastructure for international renewable hydrogen and hydrogen-based fuel trading will be operational by 2028.

IEA. CC BY 4.0.

Renewable capacity additions dedicated to hydrogen production, cumulative (left) and net (right), 2023-2028



IEA. CC BY 4.0.

Note: The forecast for renewable capacity dedicated for hydrogen production uses a similar method as the forecast for renewable capacity dedicated for power. The forecast uses the IEA Hydrogen Projects Database as a primary input and estimates a commissioning date of electrolyser projects depending on the stage of development and the overall market environment. In addition, an assessment of the government's support policies for renewable hydrogen are also used as input to the forecast. An assumption for the installed renewable capacity needed for the electrolyser is made depending on whether the final product is hydrogen or ammonia.

Global annual growth is initially driven by China, which accounts for more than 70% of net additions between 2023 and 2024. Early electrolyser deployment in this country will be mostly from state-owned enterprises developing projects to meet provincial and national hydrogen production targets, estimated to trigger 2 GW of renewable electricity capacity growth in 2023 and 4 GW in 2024. While the pace of annual growth accelerates to over 6 GW by 2028, it is constrained by the risk of uncertainty over hydrogen demand. Despite this uncertainty, however, China is expected to remain the single largest market over the forecast period, even though its share relative to the rest of the world decreases by 2028 as projects from other markets begin to be commissioned.

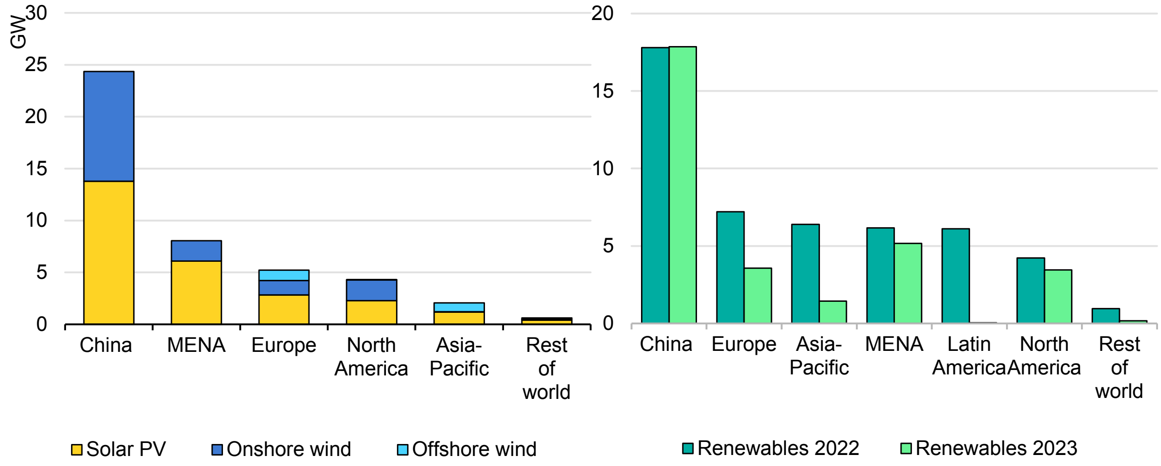
By 2025, projects in potential export countries become operational (notably Saudi Arabia's Neom project), and new EU capacity could emerge by 2026, led by Spain, Denmark and Germany. By 2028, half (50%) of global annual hydrogen-driven renewable capacity growth is expected to come from outside of China.

Between 2023-2028, 60% of global renewable power capacity dedicated to hydrogen production is expected to be solar PV. Outside of China, solar PV claims an even higher share of renewable capacity in the Asia-Pacific region (in Australia) and in the Middle East and North Africa. Globally, onshore wind is expected to account for almost 40% while offshore wind capacity for hydrogen production is forecast to be less than 2 GW (4%) by 2028 – from projects in Korea, Australia and Denmark. While many countries in Northern Europe are announcing plans to

IEA. CC BY 4.0.

produce hydrogen with offshore wind energy, commissioning would not occur until after 2028 due to Europe's long project development lead times.

Renewable capacity dedicated to hydrogen production by region and technology, 2023-2028 (left) and forecast revisions (right)



IEA. CC BY 4.0.

Note: MENA = Middle East and North Africa.

While almost all regions are still expected to increase the amount of renewable energy capacity dedicated to hydrogen production by 2028, the pace of growth is now less optimistic than in *Renewables 2022*. In fact, this year's forecast is 35% lower than in 2022 due to downwards revisions for all regions except China. The main reason is the slow pace of bringing planned projects to financial close due to a lack of off-takers and the impact of inflation on production costs. Overall, the amount of renewable energy capacity for hydrogen production growth represents only an estimated 7% of announced project capacity.

According to the [IEA Hydrogen Projects Database](), there are over 360 GW of electrolyser projects using dedicated to renewable electricity capacity with announced start dates before 2030 in the development pipeline at various stages. These range from early-stage announcements, to feasibility assessments, to later stages wherein the project has reached financial close or is under construction. However at the time of writing, only 3% (12 GW) of them had reached financial close or started construction, a smaller amount than expected in our *Renewables 2022* forecast.

In addition to challenges in securing off-takers, project development in several markets has been affected by delays in electrolyser shipments due to backlogs in manufacturing plant orders and, in some cases, by malfunctioning equipment. Some of the planned projects in the *Renewables 2022* forecast have had no updates over the last year or have been cancelled completely. The largest downward revision is for the Latin America region, due to slower than expected

IEA. CC BY 4.0.

development of project pipelines in Chile and Brazil. The forecast is also less optimistic for Asia-Pacific, mostly due to uncertainty in Australia over the future of stalled projects. One project's environmental permit had lapsed before it reached financial close, and plans for projects in Bell Bay have been put on hold due to high water and transmission congestion.

Renewable energy capacity expansion for hydrogen production needs to accelerate if governments wish to meet their 2030 targets for low-emission hydrogen production with new investments in renewable capacity. In almost all markets, main case growth is insufficient to provide the minimum amount of capacity needed to achieve government targets for low-emission hydrogen production or electrolyser capacity.

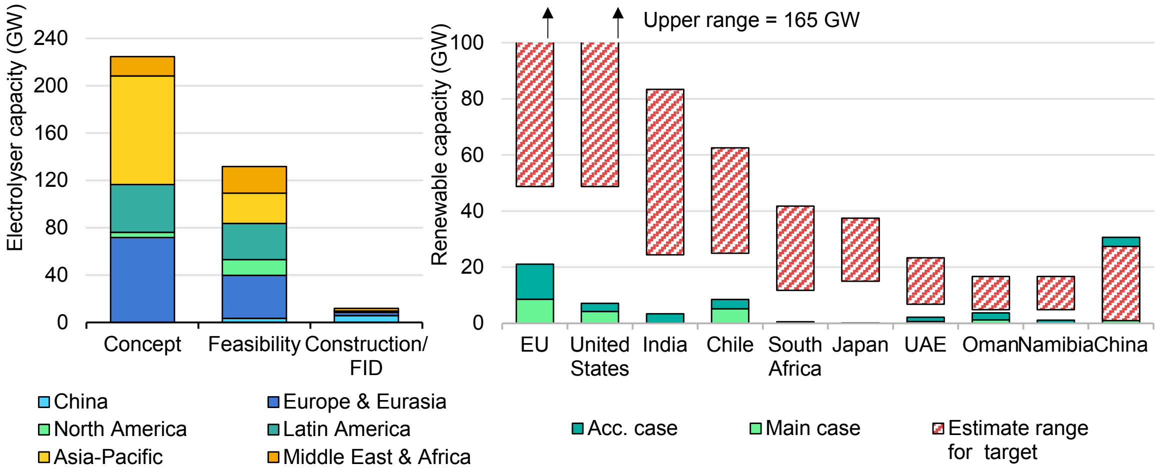
China is the only market where the pace of growth is likely to come within reach of announced goals. In the main case, renewable energy capacity for hydrogen in China exceeds 24 GW by 2028, far above the estimated 1 GW needed to produce the central government's announced target of 100 000-200 000 tonnes/year of renewable hydrogen. The main case forecast is in line with China's currently announced provincial ambitions for 2025 and 2030, wherein a majority of growth comes from state-owned enterprises building projects to meet provincial-level targets and increase system flexibility.

In the remainder of the markets, several impediments prevent faster hydrogen-driven renewable capacity growth. For instance, many of them are experiencing general permitting and grid connection challenges for new renewable electricity projects, which also apply to any capacity built specifically for hydrogen production.

Another major challenge is the lack of demand for hydrogen and hydrogen-based fuels because of the cost barrier. Renewable hydrogen costs more than unabated fossil fuels-based production currently meeting demand in existing uses (i.e. ammonia production and refining), and other affordable technologies are available for new uses (i.e. other industrial and transport uses). Therefore, government support is still needed to make renewable hydrogen and its derivatives appealing to end users. However, much of the existing policy support is focused on providing support to developers who supply hydrogen rather than the consumers.

IEA. CC BY 4.0.

Global announced electrolyser projects with 2030 commissioning dates (left), and renewable capacity dedicated to hydrogen production in the main and accelerated cases (2023-2028) vs amounts needed to meet 2030 national targets for hydrogen and electrolysers (right)



IEA. CC BY 4.0.

Notes: FID = final investment decision. UAE = United Arab Emirates. For left graph, only projects with an announced start year of 2030 or earlier are included. For right graph, the minimum range of renewable capacity needed for national electrolyser targets was calculated assuming a 1:1 sizing ratio between electrolyser capacity and renewable technology, and the maximum assumed an oversizing ratio of 1:2.5. National targets given in Mt H_2/year were converted to an electrolyser equivalent using production capacity assumptions for the different electrolyser technologies. For the minimum electrolyser capacity range, assumed production capacity is based on solid oxide electrolysis cells (0.0038 MW/nm³ H_2/hour) and for maximum electrolyser capacity it is based on proton exchange membrane electrolysis (0.0052 MW/nm³ H_2/hour). For China, the national 2025 target is considered the lower bound for the 2030 target range, and the sum of announced provincial targets is the upper bound. For the announced provinces without 2030 targets, 2025 targets were assumed as a proxy for the purposes of benchmarking in this exercise.

Sources: (left) IEA (2023), Hydrogen Production and Infrastructure Projects (database); (right) IEA analysis based on Bloomberg New Energy Finance (2023), Hydrogen Strategy Tracker, accessed October 2023, and EnergyIceberg (2023), Hydrogen Policy Navigator.

Nonetheless, progress has been made in demand-side policymaking in the last year, with some governments passing legislation or announcing intentions to do so. The accelerated case for growth during 2023-2028 assumes that these policy actions can help bring some projects in the later development stages to financial close. In Germany, renewable capacity growth could be four times higher – topping 3 GW – if the European Union approves the state aid proposed under the CfD scheme and it successfully awards bidders. The accelerated case also forecasts higher EU growth with introduction of the new Hydrogen Bank's auctions to award contracts to suppliers to bridge the price gap with alternative sources of hydrogen.

Also supporting EU accelerated case growth is the new mandatory target for non-renewable fuels of non-biological origin in industry and transport. In July 2023, the European Union passed the world's first end-use mandatory target for hydrogen: 42% of hydrogen used must be made from renewable sources by 2030 (complying with certain additional criteria on additionality, geographical correlation and temporal correlation) and at least 1% of transport fuel. However, uncertainties still

IEA. CC BY 4.0.

surround the potential for this regulation to spur new renewable capacity growth before 2028, as each Member State is at liberty to decide which policy instrument(s) it will employ (e.g. mandates, incentives, etc.).

In the United States, faster growth could happen if tax incentives under the IRA make renewable hydrogen more economically attractive than its alternatives for existing uses, and in Korea, additional projects could come online from its new auctions for clean-hydrogen electricity.

In total, the accelerated case forecasts that renewable energy capacity dedicated to hydrogen could reach 85 GW – almost twice as much as in the main case – if government support can help bring planned projects to financial close. However, this pace is still insufficient to achieve the growth needed to meet national 2030 low-emission hydrogen targets. More effort will be required to ensure that adequate infrastructure to store and transport hydrogen is in place, to clarify regulatory uncertainty, and to boost investment in R&D to improve technologies for new and existing uses.

IEA. CC BY 4.0.

Chapter 2. Transport biofuels

Global forecast summary

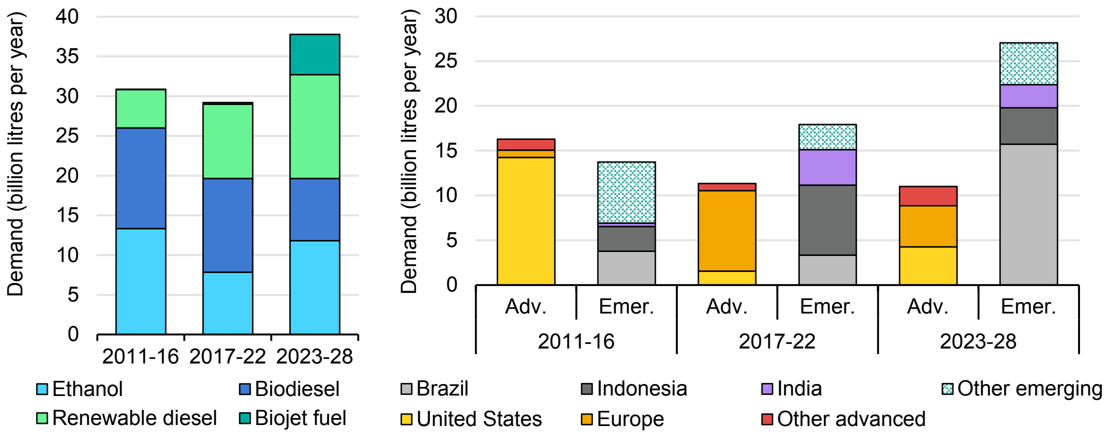
Emerging economies lead accelerating growth in biofuel use

Biofuel demand is set to expand 38 billion litres over 2023-2028, a near 30% increase from the last five-year period. In fact, total biofuel demand rises 23% to 200 billion litres by 2028, with renewable diesel and ethanol accounting for two thirds of this growth, and biodiesel and biojet fuel making up the remainder.

Most new biofuel demand comes from emerging economies, especially Brazil, Indonesia and India. All three countries have robust biofuel policies, rising transport fuel demand and abundant feedstock potential. Ethanol and biodiesel use expand the most in these regions. Although advanced economies including the European Union, the United States, Canada and Japan are also strengthening their transport policies, volume growth is constrained by factors such as rising electric vehicle adoption, vehicle efficiency improvements, high biofuel costs and technical limitations. Renewable diesel and biojet fuel are the primary growth segments in these regions.

In the accelerated case, demand growth is nearly triple the main case over the forecast as existing policies are strengthened and biofuel demand expands in new markets (see Net Zero Emissions by 2050 Scenario tracking section in this chapter).

Five-year biofuel demand growth by fuel (left) and economy type (right), main case, 2011-2028



IEA. CC BY 4.0.

Notes: Adv. = advanced economies. Emer. = emerging economies.

IEA. CC BY 4.0.

Renewable diesel and biojet fuel consumption expand 18 billion litres over the forecast period, with the United States and Europe accounting for near 80% of this increase. In the United States, key drivers include the Inflation Reduction Act (IRA), state-level low-carbon fuel standards, and Renewable Fuel Standard (RFS) blending obligations. The United States also launched a Sustainable Aviation Fuel Grand Challenge in 2021, targeting 11 billion litres of new sustainable aviation fuel (SAF) production by 2030. While the goal is not binding, it has been accompanied by funding, research and co-ordination efforts.

In Europe, the European Union has approved its latest Renewable Energy Directive (RED III), which aims to double renewable energy shares by 2030. Member states are required to align their domestic policies by 2025 with either a 29% renewable energy target or a 14.5% GHG emissions reduction target. However, we forecast only modest growth in biofuel demand because of the directive's double-counting provision, declining transport fuel demand and increases in electric vehicle and renewable electricity shares, which can count towards the target.

In addition, Sweden has proposed a 34-percentage-point drop to its transport sector GHG emissions reduction target for diesel, lowering Europe's renewable diesel demand by over 20%. At the same time, biojet fuel use expands to accommodate country-level policies in France, Sweden and Norway as well as ReFuelEU Aviation targets of 2% SAF blending by 2025 and 6% by 2030, with a 1.2% sub-target for e-fuels.

Meanwhile, ethanol and biodiesel expand by 13% over the forecast period, with growth in emerging economies offsetting declines in advanced ones. While Brazil aims to increase maximum ethanol blending to 30% from 27.5% in 2023 in addition to using pure ethanol in flex-fuel vehicles, India supports ethanol expansion through a blending target of 20% by 2025/26, guaranteed ethanol blending and financial support for new facilities.

Although European ethanol demand rises slightly over the forecast period, it is more than offset by declines in the United States, where gasoline use is expected to shrink and there has been little increase in ethanol blending shares above 10%.

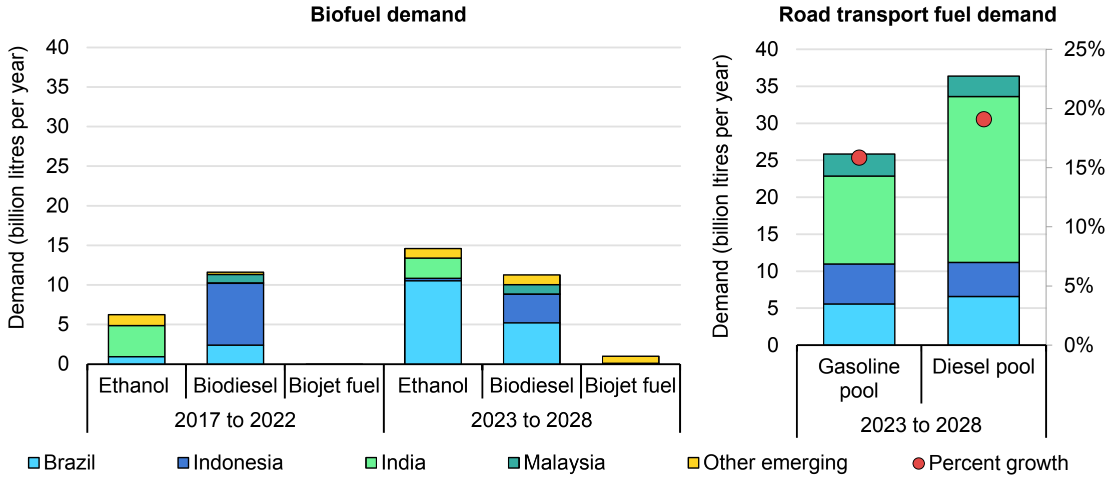
Biodiesel consumption expands primarily in Brazil, Indonesia and Brazil following increases to blending requirements and climbing diesel demand. All three regions plan to allow for and encourage renewable diesel use, but we forecast little uptake in the main case. The United States and Europe remain major markets with more than one-third of global biodiesel demand in 2028, but renewable diesel captures all new growth because of its superior blending properties.

IEA. CC BY 4.0.

Among emerging economies, Brazil, Indonesia, India and Malaysia demonstrate the most growth

Over 60% of global biofuel demand and production growth over the forecast period takes place in Brazil, Indonesia, India and Malaysia. Across these countries, ethanol use increases by 13 billion litres and biodiesel by 8 billion litres, accounting for almost all expansion in emerging economies. All four countries share key growth drivers – comprehensive policies, abundant feedstocks, high oil and oil product import dependence and rising transport demand – and biofuels feature prominently in their GHG emissions reduction plans. We expect these factors to boost biofuel expansion throughout the forecast period.

Five-year biofuel demand growth (left) and road transport demand growth (right) in emerging economies, main case, 2023-2028



IEA. CC BY 4.0.

As demand for transport fuels surges, Brazil, Indonesia, India and Malaysia will continue to rely on biofuels to help reduce oil import dependence. Across all four countries, the gasoline pool (gasoline and ethanol) is expected to expand more than 15% and the diesel pool (diesel and biodiesel) by nearly 20% over the forecast period. While these countries will rely on imports to differing degrees to satisfy rising demand (for instance, India relies near 90% on crude imports), all four are strengthening existing mandates. Globally, transport fuel demand expands only 2% by 2028.

Biofuels are, however, more expensive in all four countries, with average prices 15-80% higher than for fossil fuels on an energy basis over the last 10 years. Thus, direct fuel subsidies accompany demand targets in Indonesia, Malaysia and India to reduce the cost impact for private consumers and companies.

Indonesia has placed a levy on palm oil exports to cover the cost difference between palm oil-based biodiesel and diesel, and Malaysia uses a similar

IEA. CC BY 4.0.

approach, but India has set guaranteed prices for individual ethanol feedstocks and updates them regularly to reflect changing prices and has also modified its ethanol tax rates. In Brazil, ethanol blending of up to 27.5% (climbing to 30% over the forecast period) has been mandated, and the country also offers lower taxation on ethanol and counts it towards carbon reduction credits. These initiatives help keep ethanol prices competitive, although sugar, corn and gasoline prices also play a role. Historically, all four countries have also subsidised gasoline and diesel fuels.

Moreover, all four countries have ample domestic feedstocks, although the scale of growth will command increasing shares. While biodiesel demand already claimed 19% of palm oil production in Malaysia and Indonesia in 2022, in our main case this share climbs to 30%, even with rising palm oil production. In Brazil, the share of ethanol production derived from sugarcane is expected to remain near 50%, despite significant growth. Similarly, in India in the main case, ethanol demand as a share of sugarcane production expands to 7% by 2028 from 5% in 2022. Existing and planned biofuel production capacity in all four countries is sufficient to support domestic demand.

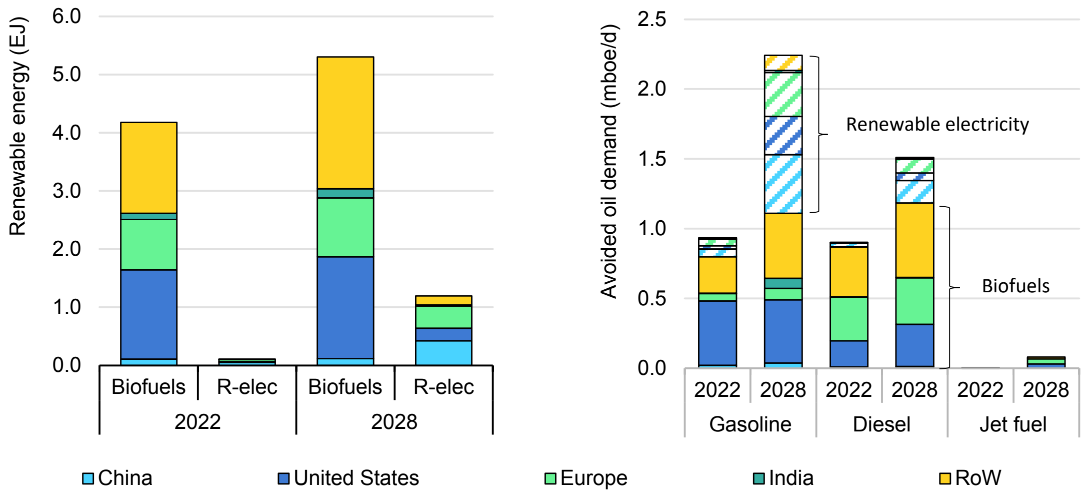
In the United States, Europe and China, electric vehicles account for the most growth in avoided oil demand

Biofuels and renewable electricity are set to reduce transport sector oil demand by near 4 mboe/d by 2028, more than 7% of forecast transport oil demand, and when electricity from non-renewable sources such as nuclear, natural gas and coal is taken into account, this value rises to nearly 9%. Renewable electricity leads growth by avoiding an additional 1.3 mboe/d of oil consumption over the forecast period, while biofuels avoid another 0.7 mboe/d. By 2028, biofuels account for near 60% of avoided oil demand and renewable electricity for the remainder.

Both biofuels and renewable electricity help meet the targets of domestic transport policies such as low-carbon fuel standards in the United States and the RED in the European Union. Historically, biofuels have reduced oil demand the most, but during the forecast period, electric vehicles claim a larger share of reductions in the gasoline segment. Nevertheless, biofuels continue to be the dominant option for reducing oil demand in the diesel and jet fuel segments.

IEA. CC BY 4.0.

Biofuels and renewable electricity in transport (left) and avoided oil demand (right), main case, 2022-2028



IEA. CC BY 4.0.

Notes: (Right) R-elec = renewable electricity used by electric vehicles. Electric vehicle renewable electricity use is consistent with our main case renewable electricity forecast. Avoided oil demand for electric vehicles accounts for the higher energy efficiency of electric vehicles compared with combustion vehicles. Electricity use for cars, trucks, vans and buses is included, but rail transport is not. (Left) RoW = rest of world. Mboe/d = million barrels of oil equivalent per day. Oil displacement estimates exclude biofuel use in each region and assume electric vehicles substitute for vehicles in the same class (i.e. an electric SUV replaces an equivalent internal combustion vehicle or hybrid). The full methodology is available in the Global EV Outlook.

Source: IEA (2023), Global EV Outlook 2023.

In the United States, Europe and China, renewable electricity use in transport is forecast to expand eightfold over the forecast period, albeit from a small base. In total, electric vehicles using renewable electricity will avoid 1.3 mboe/d of oil consumption in 2028 in these regions, about the same as biofuels. In the United States and Europe, large-scale electric vehicle growth contributes to declining gasoline demand over the forecast period.

Meanwhile, lower gasoline demand, combined with few high-ethanol-blend pumps, is limiting ethanol growth prospects in both regions. Moreover, in the European Union, using renewable electricity for electric vehicles will likely be the dominant compliance pathway to meet the revised RED's new renewable energy goals, since renewable electricity used in electric vehicles, which are more efficient than internal-combustion vehicles, counts four times towards the directive.

In much of the rest of the world, however, biofuels remain the primary decarbonisation option, accounting for near 90% of avoided oil demand in 2028. In Brazil, India and Indonesia, electric vehicles and efficiency improvements pose little threat to liquid fuel demand, given the high growth prospects for overall transport demand. These regions also mandate biofuel shares, avoiding direct competition with electric vehicles.

IEA. CC BY 4.0.

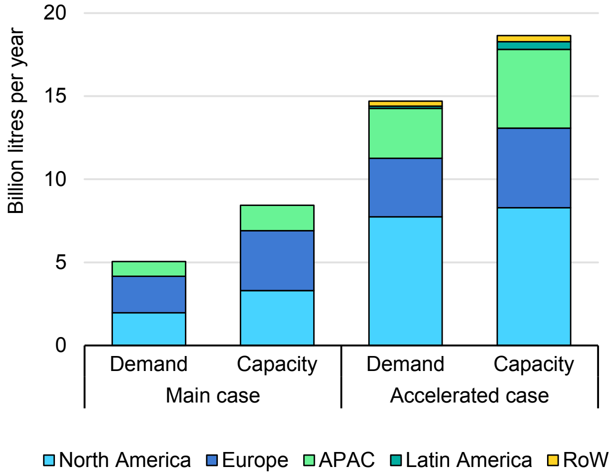
Nevertheless, Brazil, Indonesia and India all have electric vehicle plans in place. Indonesia launched purchase incentives in 2023, Brazil provides tax exemptions for electric vehicle imports and India has a mixture of national and state-level purchase and manufacturing incentives. These policies will help expand electric vehicle sales but have little impact on oil demand over the forecast period, as total vehicle stock will remain primarily combustion vehicles.

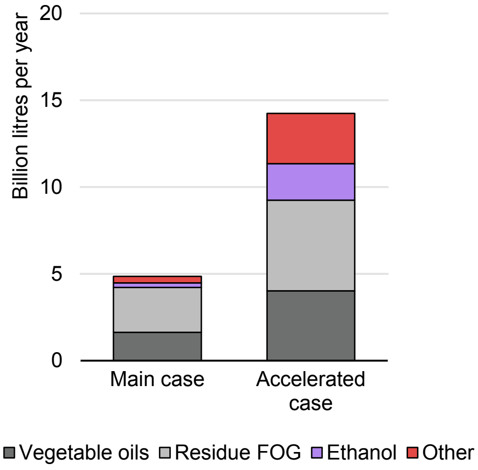
Biojet fuel demand is expected to soar with fulfilment of policy promises

Globally, biojet fuel use is expected to expand by nearly 5 billion litres, making up almost 1% of global jet fuel supplies by 2028. We have revised the forecast upwards 20% in the main case and 40% in the accelerated case to reflect new policy announcements and a robust project pipeline.

The United States, Europe and Japan are at the forefront of this growth, propelled by strong policy support. Ongoing policy discussions in Brazil, India, Indonesia, Singapore, the United Arab Emirates, Malaysia and the United Kingdom, coupled with significant capacity potential in the United States, could boost demand to 15 billion litres, or to 3.5% of global jet fuel demand in 2028 in our accelerated case. However, realising this growth will hinge on policy implementation and feedstock diversification.

Biojet fuel five-year growth in demand and capacity additions (left) and feedstocks (right), main and accelerated cases, 2023-2028





IEA. CC BY 4.0.

Notes: APAC = Asia-Pacific region. RoW = rest of world. FOG = fats, oils and grease. Capacity potential is based on project announcements. Main case potential capacity includes projects under construction, having obtained a final investment decision or highly likely to be constructed. The accelerated case includes all proposed projects that have a planned production date. “Vegetable oils” indicates soybean oil, rapeseed oil, palm oil and corn oil; “Residue FOG” includes used cooking oil, animal fats and palm oil mill effluent; and “Other” covers wood wastes, municipal solid waste and unknown feedstocks.

Sources: Capacity estimates adapted from Argus and S&P data, and company announcements.

IEA. CC BY 4.0.

In the main case, incentives such as IRA credits, the Renewable Fuel Standard's Renewable Identification Numbers (RINs), and Low Carbon Fuel Standard (LCFS) credits help raise US biojet fuel demand to nearly 2 billion litres by 2028. These credits, potentially worth near USD 1/litre,[1] narrow the price gap with fossil jet fuel. Meanwhile, EU ReFuelEU Aviation legislation, which sets blending obligations of 2% for 2025 and 6% for 2030, is forecast to increase the biojet fuel share to 4% of Europe's jet fuel demand by 2028. In the Asia-Pacific region, Japan is the main source of demand growth with its goal of 10% sustainable aviation fuel by 2030.

The accelerated case is predicated on the implementation of planned policies and feedstock diversification. Active policy discussions in Singapore, Malaysia, Indonesia, India, the United Arab Emirates, Brazil and the United Kingdom would help trigger an additional 30% increase in biojet fuel demand to 2028 (see the table below in Net Zero Emissions by 2050 Scenario tracking section, in this chapter, for a detailed policy list). However, the United States has the most significant upside potential in the accelerated case. Under a more stringent Renewable Fuel Standard, higher state-level LCFSs and extended IRA credits, biojet fuel production could triple, advancing the country two-thirds of the way to achieving its SAF Grand Challenge goal.

Beyond implementing new policies, it is critical to establish new feedstock sources, as residue fat, oil and grease supplies are limited and EU policies require non-food/-feed feedstocks. In the accelerated case, planned alcohol-to-jet projects deliver almost 2 billion litres of new capacity, and the gasification of woody residues and municipal solid waste offer another 2 billion litres of potential.

The appetite for low-emissions e-fuels is growing in the aviation and marine subsectors

Demand for low-emissions e-fuels,[2] particularly for aviation and marine transport, is forecast to climb to over 3 billion litres by 2030 owing to EU transport policies and industry offtake agreements. While high costs, a paucity of demand policies and few firm project commitments limit growth prospects for e-fuels, declining hydrogen and renewable electricity costs, coupled with production advances, could make e-fuels competitive with biojet and biodiesel or renewable diesel biofuels by 2030. However, this potential competitivity does not necessarily

[1] Assuming a GHG intensity of 18 gCO_2/MJ for biojet fuel, an LCFS credit price of USD 60/tonne, a D4 RIN price of USD 1/gallon and an IRA SAF tax credit of USD 0.41/litre.

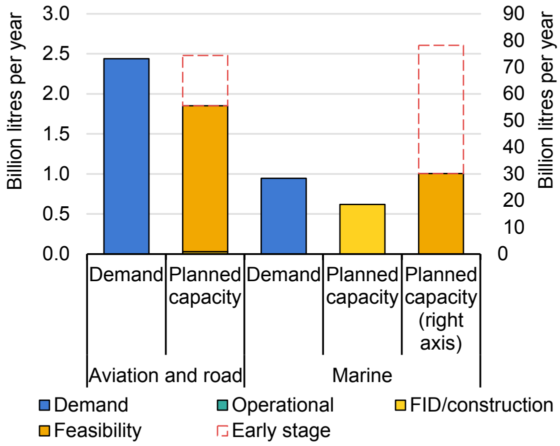
[2] Low-emissions e-fuels are fuels obtained from electrolytic hydrogen. Combining hydrogen with either nitrogen or CO_2 produces different fuel products such as e-kerosene, e-gasoline, e-diesel, e-methanol and e-ammonia. E-kerosene, e-gasoline and e-diesel can be blended with fossil fuels relatively easily, but using e-ammonia and e-methanol for transport fuel requires investments to adapt distribution infrastructure and end-use equipment.

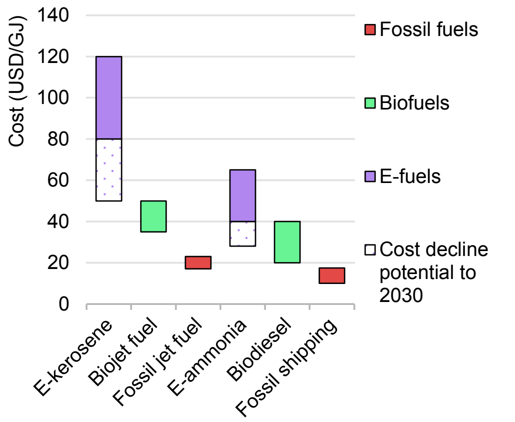
IEA. CC BY 4.0.

threaten biofuel production, as net zero targets require the accelerated deployment of both types of fuels.

E-fuels also serve as a low-emissions complement to biofuels, as they provide a market for utilising CO_2 from biofuel facilities, primarily ethanol plants, which offer some of the lowest-cost point sources for CO_2 potential globally. In fact, total CO_2 from ethanol facilities could support the production of 26 billion litres of e-kerosene per year, equivalent to 6% of global jet fuel demand. Moreover, many ethanol facilities are located in countries that also have strong SAF goals (e.g. the United States and Europe) or ambitions to adopt SAF targets (e.g. Brazil).

E-fuel demand and planned capacity additions to 2030 (left) and levelised cost ranges (right)





IEA. CC BY 4.0.

Notes: FID = final investment decision. Aviation and road demand estimates are based on offtake agreements for e-fuels and EU policy commitments to 2030. Marine demand estimates are based on offtake agreements for e-ammonia and e-methanol to 2030. Planned capacity is based on the IEA Hydrogen Project Database. Planned marine capacity includes methanol and ammonia specifically for transportation purposes. Fuel cost estimates are based on the levelised cost of production for e-fuels and biofuels. Fossil fuel prices are market averages.

Sources: For SAF offtake agreements and global hydrogen offtake agreements for green ammonia: Argus (2023), The Role of Low-Emissions e-fuels in Decarbonising Transport.

In the aviation sector, e-fuel use is promoted primarily by the RefuelEU Aviation programme (which requires an e-kerosene minimum of 0.7% and an average of 1.2% by 2030/31), RED III (a 1% sub-target for e-fuels by 2030) and Germany's SAF mandate (2% e-kerosene fuel by 2030). There is also some growth in the road transport market to meet the RED III commitment, but it would likely be met with e-gasoline produced as a byproduct during e-kerosene production.

Meanwhile, offtake agreements between fuel producers and consumers boost marine sector demand for e-ammonia and e-methanol. Offtake agreements with firm e-fuel volume commitments cover just under 1 billion litres per year to 2030, and all were announced in the last two years. Upside potential in this area is considerable, as the International Maritime Organization aims to have 5-10% of

IEA. CC BY 4.0.

marine fuels come from net zero or nearly net zero sources by 2030, although new policies to support this target are not expected until 2027. The European Union has also approved ReFuelEU Maritime legislation, but e-fuel requirements are not reflected in this analysis because they will not be introduced until 2034.

In addition, while the United States has no e-fuel mandate, the combined value of IRA credits for hydrogen, SAF and carbon capture, in addition to RFS credits and state-level LCFS credits, could reach USD 80/EJ depending on credit market prices. However, these incentives have not yet secured firm project commitments for e-kerosene fuel.

Forecast demand thus far exceeds firm project commitments to 2030. However, since EU e-fuel mandates were just introduced in 2023, as were most offtake agreements, we assume there will be more final investment decisions in upcoming years. For aviation, the almost 2.5 billion litres of planned capacity additions would directly supply e-kerosene to meet mandates and offtake agreements. However, e-ammonia, which can be used in shipping, can also serve agricultural markets and be used in power generation applications. Having access to multiple potential markets helps reduce investment risks for this fuel and explains why there are more firm and planned e-ammonia project commitments.

Net Zero Emissions by 2050 Scenario tracking

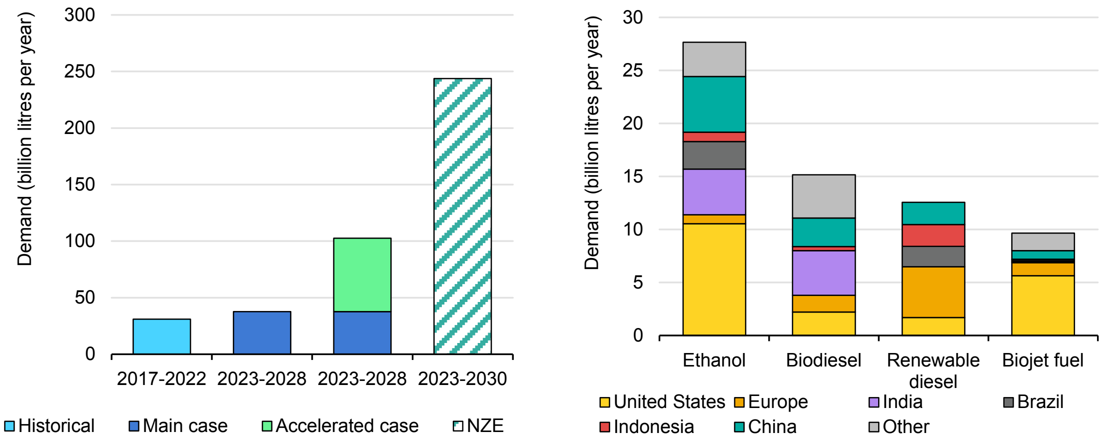
Biofuel production falls short of IEA Net Zero objectives

In our accelerated case, biofuel production falls short of Net Zero Scenario goals. Strengthening existing policies, establishing new targets, expanding feedstock supplies and raising biojet fuel use are essential to close the gap. While the main case achieves only 15% of the growth needed, the accelerated case still raises global biofuel production to only near 40% of Net Zero ambitions.

In the accelerated case, compound annual growth could reach over 8% over the forecast period, more than double historical rates. Nearly half of this additional growth, 29 billion litres of new demand, results from strengthened policies in existing markets such as the United States, Europe and India (for ethanol), and an additional 21 billion litres comes from new markets (biodiesel in India and ethanol in Indonesia). Biojet fuel offers a third growth avenue, expanding to cover nearly 3.5% of global aviation fuels – up from 1% in the main case. Each pillar faces its own set of challenges, however.

IEA. CC BY 4.0.

Forecast vs Net Zero Scenario demand growth, 2017-2030 (left) and additional demand growth in the accelerated case, 2023-2028 (right)



IEA. CC BY 4.0.

Note: NZE = IEA Net Zero Emissions by 2050 Scenario.

Source: IEA (2023), Net Zero Roadmap: A Global Pathway to Keep the 1.5°C Goal in Reach.

In the United States, Europe and India, expanding supply depends in part on strengthening existing policies, promoting high-ethanol blends and diversifying feedstock supplies. In the accelerated case, the European Union aims for a stronger transport target of 32% by 2030, up from 29% in the main case. As most new growth is expected to come from non-food/-feed crops, new feedstock supplies and processing technologies will be needed.

In the United States, additional growth is premised on a quicker rollout of E15 ethanol pumps and a permanent allowance for E15 blending, bringing average ethanol blending to nearly 13%. As with Europe, accelerating renewable diesel production will require quicker deployment of processing technologies that can make use of wastes and residues, and innovative agricultural practices to produce plant feedstocks that do not compete with food or feed production. In the accelerated case, high-ethanol blends and increased feedstock availability allow for higher RFS requirements post-2025. India meets its 20% blending target by expanding ethanol production, increasing the number of E20 pumps and diversifying feedstocks beyond sugarcane and molasses.

New, comprehensive policy packages will be necessary to expand biodiesel production in India, ethanol in Indonesia and renewable diesel in Brazil and Indonesia. Developing biodiesel production in India, for instance, will require capacity expansion, closing of the cost gap with diesel, and feedstock mobilisation. Since India imports 60% of its vegetable oils, feedstock growth should be based on used cooking oils and animal fats, or vegetable oils grown as cover crops or on

IEA. CC BY 4.0.

marginal land. In Africa as well, eight countries have biofuel blending targets at various levels of development, which could raise the continent's demand more than 2 billion litres by 2028.

Meanwhile, Indonesia will need clear targets, sustainability guidance, expanded sugarcane production and financial support to increase its ethanol production. Likewise, for Brazil and Indonesia to expand their renewable diesel supplies, they will have to establish technical specifications, pricing support and guidance on how renewable diesel production will complement existing biodiesel production.

Biojet fuel use expands considerably in the accelerated case, climbing to 3.5% of global aviation demand by 2028. Achieving this market share hinges primarily on the United States – but also Europe and Japan – meeting their biojet fuel goals. These regions will also need to employ new feedstock sources (e.g. vegetable oils grown on marginal land) and processing technologies (such as alcohol-to-jet conversion) to avoid feedstock limitations.

The accelerated case also includes biojet fuel development in Brazil, Indonesia, China and India, assuming that existing policy plans are implemented. Initial growth in Brazilian projects would likely focus on soybean oil and in Indonesia on palm oil, while India and China would need to rely on advanced fuels. By 2028, 2% biojet fuel blending would result in airline ticket price increases of nearly 1.5%, equivalent to an additional cost of USD 1 for a flight between New Delhi and Chennai, for instance.

To align biofuel production with the IEA Net Zero Scenario, it will be necessary to enter new markets; increase feedstock supplies; accelerate technology deployment; and reduce GHG emissions intensity. In the Net Zero Scenario, biofuels make up 8% of shipping fuel and 10% of aviation fuel by 2030, up from nearly zero in 2022 and well above accelerated case projections.

As over 80% of biofuel demand is concentrated in just four markets – the United States, Brazil, Europe and Indonesia – which account for only half of global transport fuel demand, policy lessons from these markets can be used to expand production in other regions. At the same time, conventional and waste-based feedstock supplies will have to be enlarged through enhanced land productivity and residue collection, underpinned by robust sustainability frameworks.

New processing technologies to access a large agricultural and forestry residue base must also quintuple by 2030, necessitating significant developmental support, as most remain pre-commercial. Finally, to address GHG emissions intensity, technologies such as CCUS applied to biofuel projects can very effectively reduce GHG emissions, with lower feedstock demand. In all cases, predictable long-term policies are crucial to minimise uncertainty and stimulate investment.

IEA. CC BY 4.0.

Table 2.1 Policies and assumptions, main and accelerated cases

Country or region	Main- and accelerated-case policies, assumptions and blending levels
United States	**Main case:** Existing Renewable Fuel Standard commitments remain in place. IRA provisions are implemented as presented in the act. Ethanol blending reaches 10.7% and exports climb to 2018 record levels of 7 billion litres by 2028. Renewable diesel expands according to planned capacity additions from projects in advanced development stages. Renewable diesel blending reaches 9% in 2028. Biodiesel blending declines to 2.7% while biojet fuel supply and demand expand to accommodate 2% blending for all jet use. Biojet fuel makes up almost 15% of renewable diesel production in 2028. **Accelerated case:** A strengthened version of the Renewable Fuel Standard boosts domestic biofuel demand, combined with extended IRA credits, deployment of E15 blending pumps and stronger state-level LCFSs. Combined, these policies help achieve blending rates of 13% for ethanol and 4% for biodiesel. Renewable diesel blending increases to 10%, requiring additional production capacity beyond projects in advanced development stages. Biojet fuel blending expands to 8%, nearly two-thirds 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.
Brazil	**Main case:** Brazil increases mandatory ethanol blending to 30%, and hydrous ethanol purchases expand so that total blending reaches 58% by 2028. The biodiesel grade reaches B11 in 2023, climbing to B15 by 2025. There is a small amount of renewable diesel blending (0.8%) by 2028 based on planned project additions. The forecast assumes soybean oil prices decline from 2021/22 records but remain high compared with historical levels. **Accelerated case:** Brazil achieves its B15 blending target as in the main case but also accepts renewable diesel and co-processing so that additional renewable diesel growth results in 3% blending in 2028. Ethanol blending expands marginally but more quickly, to 62% in 2028. Part of total ethanol blending is a continuation of blending requirements of 30%. Hydrous ethanol sales (100% ethanol) make up the remainder of ethanol demand. The proposed aviation GHG emissions reduction target is implemented, requiring 2% biojet fuel blending by 2028. 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:** India achieves 13% ethanol blending on average across the country by 2028 and all fuel ethanol is produced domestically. E20 is available starting in 2023, although the forecast assumes that vehicle incompatibility limits ethanol uptake. Biodiesel blending remains around 0.25%. **Accelerated case:** India achieves its 20% ethanol blending mandate in 2026 and advances towards its 5% biodiesel blending goal, reaching 4.5% by 2028, assuming it resolves vehicle compatibility issues and establishes used cooking oil collection. It continues to support domestic production and allows fuel ethanol imports of up to 20% of demand. India also follows through on ambitions for biojet fuel blending, reaching 2% by 2028 for international flights. This would require 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%. Ethanol imports hold steady around 2020/21 levels. Biodiesel exports remain near 2022 levels and renewable diesel exports expand according to planned project additions in advanced development stages. **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 1.3% for SAFs in domestic aviation by 2028. 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 following plans to scale up biofuel use in diesel vehicles and shipping.

IEA. CC BY 4.0.

<table>
<tr><th>Country or region</th><th>Main- and accelerated-case policies, assumptions and blending levels</th></tr>
<tr><td>Indonesia</td><td>Main case: Biodiesel blending increases to 35% by 2028 for transport and nearly 35% for non-transport uses. The main blending source is biodiesel at 34%, followed by renewable diesel at 3%. Biodiesel use remains below 35% because of compatibility issues, and renewable diesel is limited to planned projects. Ethanol demand expands to permit 0.8% for blending, reflecting fuel distributor targets and Indonesia’s intention to blend more diesel. Biojet fuel production and use climb based on planned projects, reaching 2% of jet fuel demand by 2028.

Accelerated case: Indonesia meets the B40 mandate for transport and non-transport fuel consumption and aims for B45. This requires additional renewable diesel manufacturing capacity. Indonesia also enforces SAF blending of 2% by 2025 and 4% by 2028. Exports remain small, as most production is dedicated to domestic demand. Ethanol blending reaches 10% by 2028.</td></tr>
<tr><td>Europe</td><td>Main case: EU member countries implement the Renewable Energy Directive III or their own domestic targets if more stringent, and non-EU countries achieve domestic targets. Biojet fuel use expands to meet the ReFuelEU 2%-by-2025 target and 6% by 2030, reaching 4% by 2028. 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 18% by 2028, up from 7%. 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 15% assuming ongoing support for E85; biodiesel blending remains flat; renewable diesel blending expands to 3.5%; and biojet fuel reaches 4% by 2028.
• In Spain, ethanol blending climbs to 6% while biodiesel blending remains flat, but renewable diesel blending expands to 6% and biojet fuel to 3.5%.
• Finland, the Netherlands and the United Kingdom all achieve near-10% ethanol blending. Sweden reduces its blending obligations from 58% to 8% by 2030 for biodiesel/renewable diesel, and from 24% to 8% by 2028 for ethanol; it also reaches 3% biojet fuel blending. Finland reduces its blending requirements to 22.5% by 2027, down from a 34% target by 2030. In Italy, renewable diesel blending expands to 5%.
• The United Kingdom makes progress towards its target of 10% SAF blending by 2030, with the mandate starting in 2025. Norway continues working towards its 0.5% SAF target.
• Poland implements E10 reaching near 10% ethanol blending by 2028.

Accelerated case: Sweden and Finland reinstitute their GHG intensity and blending requirements. The European Commission strengthens the RED to a 32% renewable energy share for transport. The European Union maintains and strengthens sustainability requirements for biofuels, which limits some imports. The United Kingdom establishes a 10%-by-2030 SAF target, reaching 6% blending by 2028.</td></tr>
<tr><td>Other countries</td><td>Main case: Canada continues with its Clean Fuel Standard in 2023, and Malaysia’s B20 mandate is implemented. Thailand makes progress on its E20 target, reaching 15% blending by 2028, while biodiesel use expands to 10% based on government support plans. Singapore’s renewable diesel and biojet fuel production expand to fill domestic shortfalls in the rest of the world. Argentina’s biodiesel blending climbs to 10% and ethanol to 12%. Colombia reaches 10% ethanol blending by 2028, 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 pursues 5% SAFs by 2030 and the United Arab Emirates achieves its 0.7-billion-litre SAF target, with 0.4 billion coming from biojet fuel. Brazil implements its GHG emissions intensity target for aviation, achieving 2% biojet fuel blending by 2028, while 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 2028.</td></tr>
</table>

IEA. CC BY 4.0.

Technology, market and policy trends

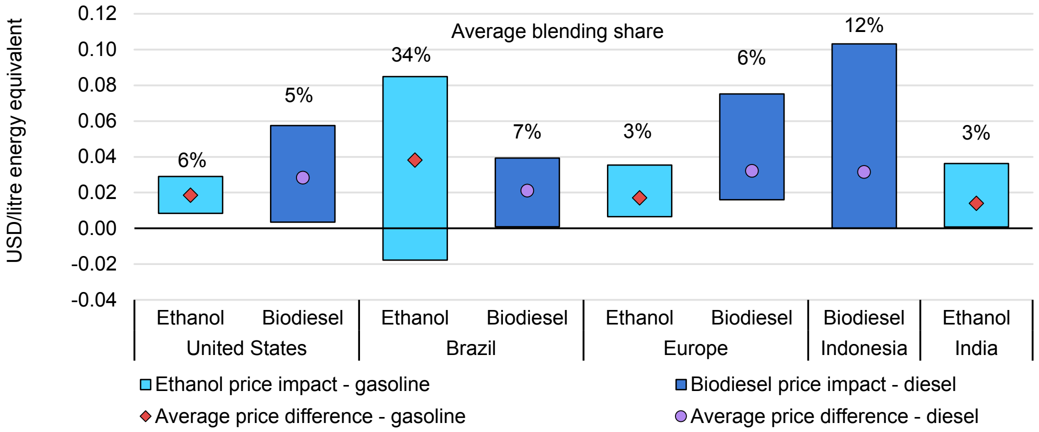
Biofuel subsidies have been costing countries 1 to 4 US cents per litre

Biofuels typically cost more than the fossil fuels they are blended with. However, the impact on fuel prices is relatively small, in the range of 1-4 US cents per litre-eq of blended fuel (on an energy-equivalency basis)[3] over the past 13 years in the United States, Brazil, Europe, Indonesia and India. This has equated to a 2-7% increase in pre-tax gasoline and diesel prices.

Countries with cheaper biofuels, such as Brazil, achieve higher blending rates with similar financial support. For instance, one litre of 34% ethanol-blended fuel (on an energy basis) in Brazil has cost an extra 4 US cents per litre-eq on average over the past 13 years. In the United States, a 6% blend (on an energy basis) has raised prices by about 2 US cents per litre.

Governments accept these additional costs to meet energy security, GHG emissions reduction and agricultural support objectives. However, variables such as feedstock costs and fluctuating oil prices can disrupt these averages, requiring flexible support mechanisms that can adapt to changing prices and mitigate high costs.

Implicit subsidy ranges for biofuel blends, and average blending shares on an energy basis by fuel, 2010-2023



IEA. CC BY 4.0.

Notes: The blended cost is the total value of the gasoline with ethanol, or the biodiesel/renewable diesel with conventional diesel. Implicit subsidies are calculated by subtracting the gasoline or diesel price from the blended cost. The octane benefit of ethanol is estimated at USD 0.02-0.05/litre depending on the year and country, and it is incorporated into ranges and averages. Price differences are based on energy equivalents, not volumes, and ranges reflect annual averages between 2010 and 2023. Average blending shares indicate each region's biofuel energy share in total transport energy demand. For Brazil, anhydrous and hydrous costs were estimated separately and then combined for an average cost.
Sources: Pre-tax market prices for gasoline, diesel, ethanol, biodiesel and renewable diesel are from Argus and S&P Global. Prices include production and distribution.

[3] Note that all blending rates and cost estimates are quoted on a per-litre, energy-equivalent basis, not on a per-volume basis. For instance, ethanol blending in the United States is nearly 10% on a volume basis, but on an energy basis it is closer to 6%.

IEA. CC BY 4.0.

Governments deploy various tools to bridge biofuel cost gaps, stimulate production and shield consumers from cost increases. In Indonesia, palm oil export levies subsidise biodiesel costs, while the United States offers a biodiesel blending tax credit of USD 0.26 per litre. It plans to extend the tax credit through the IRA, with added incentives for lower GHG emissions. India has set ethanol purchase prices at a level that enables ethanol producers to cover their costs and has lowered tax rates for ethanol and ethanol-blended fuels. Meanwhile, policy approaches across Europe differ, with some countries providing tax benefits (such as France's tax breaks on 85% ethanol blends) and many others passing the costs on to consumers.

The level of financial support needed for biofuels can change quickly, however. In Indonesia, rising palm oil prices and higher biodiesel mandates pushed subsidy costs from 1 US cent in 2019 to 10 US cents per litre-eq in 2021, leading to subsidy adjustments and a halt in blending increases. Brazil faced a similar situation, with the cost of blended diesel fuel rising from almost nothing to 4 US cents per litre-eq in 2021 due to higher soybean oil prices, prompting a slowdown in biodiesel mandate increases. However, favourable conditions such as high gasoline and low sugar prices have occasionally made ethanol blending financially beneficial in Brazil.

While the cost gap for biodiesel blends widens over the forecast period, ethanol remains steady

Biodiesel-blend fuel costs are forecast to rise with higher blending levels and increasing feedstock prices, particularly in the United States and Indonesia. Conversely, ethanol-blend fuel costs are likely to remain steady or even decline in some regions thanks to stable or decreasing prices for dominant feedstocks such as sugarcane and corn.

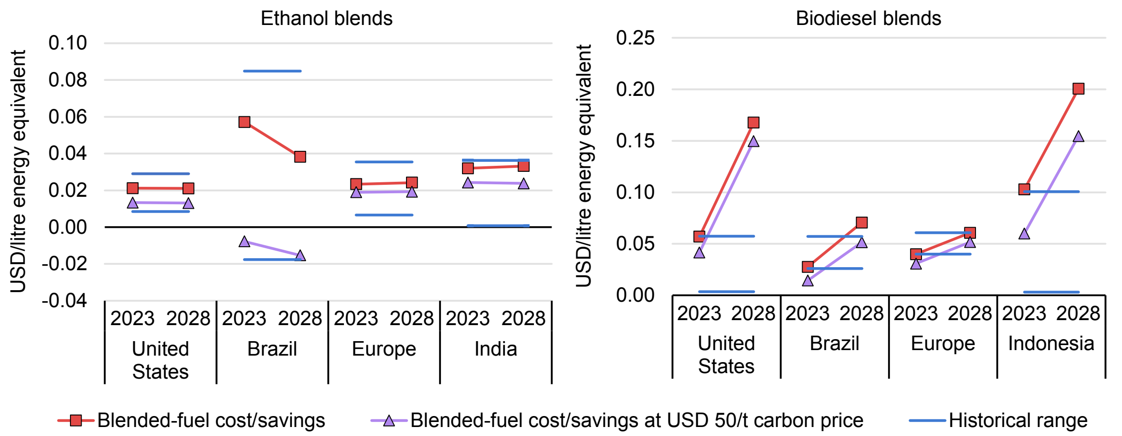
These estimates are indicative only, however, as they are based on macro-trends such as global population growth, dietary patterns, planting rates and yield improvements with impacts on global supply and demand. Agricultural commodity prices can vary considerably year over year and are the primary determinant of biofuel production costs.

Ethanol-blend fuel prices are likely to remain within historical bounds, as both blending rate and feedstock price increases are expected to be moderate. In Brazil, for instance, ethanol blending rates climb 10 percentage points over the forecast period, but the cost difference with pure gasoline falls from 6 to 4 US cents per litre. Costs decline because sugar and corn prices were near peak levels in 2023 due to weather-related supply disruptions and ongoing upward pressure on grain prices from supply risks after Russia's invasion of Ukraine.

IEA. CC BY 4.0.

In Europe and the United States, modest blending increases are anticipated, with feedstock prices remaining around historical levels. In India, feedstock prices remain flat, but increasing ethanol blending means blended-fuel costs increase to near the upper historical range.

Forecast implicit subsidy ranges in the main case, and historical averages, 2010-2028



IEA. CC BY 4.0.

Notes: The blended cost is the total value of the gasoline with ethanol (left) and the biodiesel/renewable diesel with conventional diesel (right). Implicit subsidies are calculated by subtracting the gasoline or diesel price from the blended cost. Historical ranges are based on average annual maximum and minimum implicit subsidies between 2010 and 2023. Future gasoline and diesel prices are equal to average prices between 2010 to 2023, whereas future biofuel prices are based on estimated production costs using forecast feedstock prices from the OECD-FAO Agricultural Outlook 2023-2032.

The consumption of biodiesel blends is expected to rise in major markets as blending shares and feedstock prices increase. In the United States, for instance, the blending share for biodiesel and renewable diesel combined climbs near 20% over the forecast period. Prices for vegetable oil feedstocks such as soybean oil and palm oil are also expected to remain above historical levels as demand increases globally while production remains constrained. Accelerating growth in the consumption of more expensive renewable diesel in the United States and Europe also contributes to cost increases, with the better blending properties of renewable diesel justifying its higher price.

Mitigating these price increases could involve several strategies, such as expanding and diversifying feedstock supplies through agricultural productivity improvements and new processing technologies. Lowering the carbon intensity of fuels can also contribute to more efficient feedstock use, and implementing carbon pricing could reduce the relative cost of biodiesel blends.

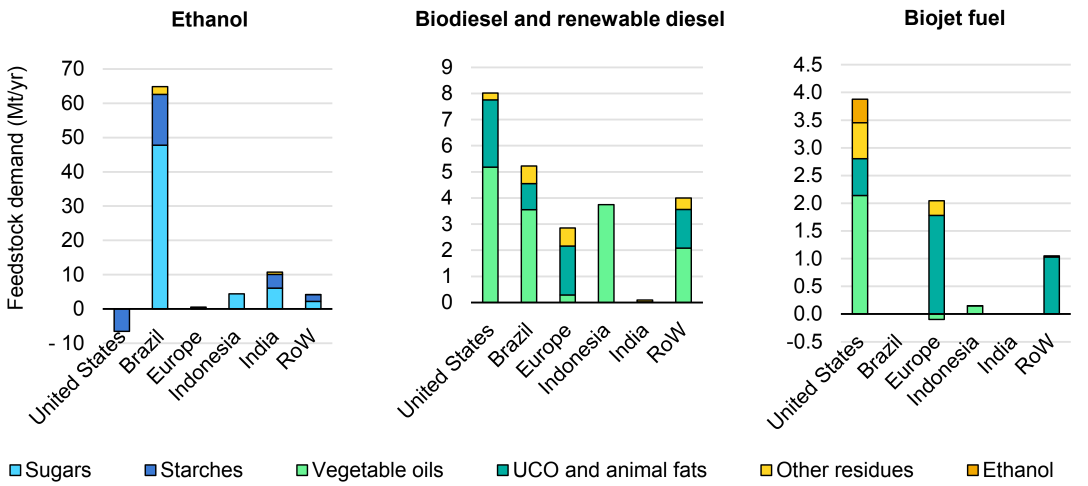
Crops support most biofuel growth, but demand for waste and residues is increasing

Nearly 75% of new biofuel demand over the forecast period is met by conventional crops, particularly sugarcane in Brazil and vegetable oils in the United States.

IEA. CC BY 4.0.

However, the share of vegetable oils used in biofuel production is expected to rise from 19% in 2022 to 24% in 2028, putting pressure on global supplies. The use of residue fats, oils and greases, such as used cooking oil and animal fats, expands the most in the United States and Europe, where they receive preferential policy treatment. Meanwhile, agricultural and forestry residues and municipal wastes used to produce ethanol, renewable diesel and biojet more than double by 2028.

Biofuel feedstock demand growth by fuel and region, main case, 2023-2028



IEA. CC BY 4.0.

Notes: RoW = rest of world. UCO = used cooking oil. Forecast feedstock demand is based on the production forecast, planned capacity additions (with stated feedstock preferences) and policy-imposed feedstock limits.

Crops, primarily sugarcane and corn, support more than 95% of new ethanol production over the forecast period. Globally, the portion of sugars and starches designated for biofuel production climbs just one percentage point to 14% of global production. Even in Brazil, the share of sugarcane dedicated to ethanol remains flat despite a 40% increase in ethanol production, thanks to an expansion in sugar supplies and growing corn-based ethanol production. In the United States, corn demand for ethanol is down slightly due to a marginal decline in ethanol production over the forecast period. Other regions show minimal new demand for ethanol feedstocks.

The United States accounts for over half of new demand for renewable diesel feedstocks, primarily vegetable oils and residue fats, oils and greases. Globally, vegetable oil demand expands more than 40% by 2028, driving increased vegetable oil production in the United States and Canada. Nevertheless, biofuel demand increases more quickly than vegetable oil production, putting pressure on supplies.

Although tax credits and loan programmes are supporting feedstock expansion through several projects to convert wood wastes into renewable diesel, planned

IEA. CC BY 4.0.

volumes remain small. In Europe, the RED and national policies are steering production towards wastes and residues, but elsewhere, palm oil in Indonesia and soybean oil in Brazil feed most additional production.

Wastes and residues are anticipated to account for about 60% of biojet fuel growth over the forecast period. In the United States, grant and loan programmes such as the Fuelling Aviation's Sustainable Transition loan programme support new production pathways, and a dedicated tax credit for biojet fuel rewards lower-GHG-emissions-intensity fuels. In the European Union, ReFuelEU Aviation legislation excludes food and feed crops, directing biojet fuel producers towards used cooking oil, animal fats and other residue oils. As with the United States, a few projects relying on woody wastes and other residues will likely be commissioned.

Biofuel producers will need to focus more on reducing GHG emissions over the next five years

In the next five years, nearly 40% of road transport fuel demand will be covered under policies incentivising lifecycle carbon reductions, marking a shift from traditional biofuel blending mandates. The value of these credits differs by market, with credits worth nearly USD 0.5/litre for biojet fuel in the United States, and USD 0.03/litre for ethanol in Brazil. This change often also brings liquid biofuels into direct competition with other GHG emissions reduction technologies such as electric vehicles and biogas.

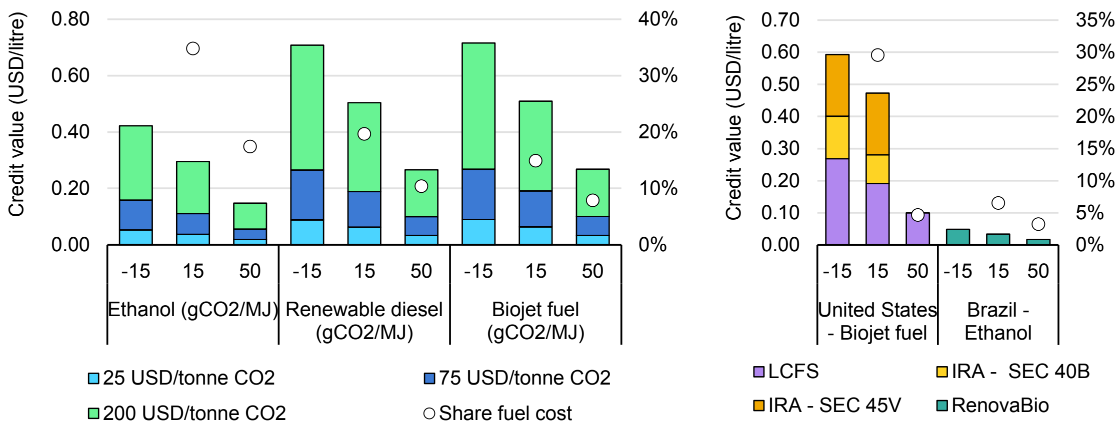
Low-carbon fuel standard credits per tonne of reduced GHG emissions have been worth up to USD 0.50/litre, although average credit prices are closer to USD 0.20/litre for biofuels substituting for diesel or jet fuel. Cleaner fuels are also allocated a higher value, with one litre of low-GHG-intensity renewable diesel (15 g CO_2-eq/MJ) earning USD 0.20/litre, double the credit of higher-intensity (50 g CO_2-eq/MJ) fuel.

The United States, Canada and the European Union will implement policies that directly incentivise GHG emissions reductions over the forecast period, adding to existing initiatives such as Brazil's RenovaBio and various state and provincial policies in the United States and Canada. Each proposed policy has its own unique design, but they generally establish a GHG emissions reduction target, lifecycle emission factors, a credit trading market and rules for fuel eligibility. The value of these credits can vary significantly across regions and over time. Credits in California, for instance, have climbed to more than USD 200/t CO_2 but they traded at an average of just under USD 75/t CO_2 in 2023. In Brazil, RenovaBio credits traded at USD 23/t CO_2 in 2023, near peak levels.

IEA. CC BY 4.0.

The United States offers a different approach with the IRA, linking tax credits to GHG emissions performance and thereby retaining incentives for incremental improvements. For instance, the clean fuel production tax credit for SAF offers USD 0.33/litre for SAF that has a 50% lower GHG intensity than fossil fuels. However, an additional USD 0.13/litre is available for fuels that beat the minimum. This credit can also be combined with low-carbon fuel standard credits in the states that have them, and potentially other IRA credits for clean hydrogen production. It does not, however, regulate a final GHG emission intensity for the aviation sector, or other fuel uses. The International Maritime Organization is also considering introducing a low-carbon fuel standard and a carbon price for international marine fuels, but details have not been published so it is not considered in our forecast.

Value of low-carbon fuel standard-type policies based on carbon intensity, credit value and fuel type (left), and carbon credit value based on existing carbon intensity policies (right)



IEA. CC BY 4.0.

Notes: LCFS = low-carbon fuel standard. IRA = Inflation Reduction Act. Credit values in the left graph are based on the difference between the example biofuel lifecycle carbon intensities (-15, 15 and 50 g CO_2/MJ) and default lifecycle carbon intensities for gasoline (85 g CO_2/MJ), diesel (89 g CO_2-eq/MJ) and jet fuel (89 g CO_2/MJ). "Share of fuel cost" is the value of the carbon credit relative to the estimated levelised cost of production for ethanol, renewable diesel and biojet fuel in 2023. US biojet credits in the right graph are based on an LCFS credit value of USD 75/t CO_2 and the value of Sec. 40B – sustainable aviation fuel credit – beyond the minimum threshold and IRA Sec. 45V for hydrogen with a carbon intensity below 0.45 kg CO_2-eq/kg H2. Biojet fuel in the United States is also eligible for the RINS under the RFS (estimated at USD 0.48/litre) and the base Sec. 40B value of USD 0.33/litre. Fuel share is based on the levelised cost of producing biojet fuel using low-GHG-intensity hydrogen and used cooking oil. Brazil's ethanol value is based on the average 2023 RenovaBio credit value of USD 23/t CO_2 and the value per litre of ethanol at different lifecycle GHG intensity values. The share of fuel cost of these credits is based on the estimated levelised production cost for sugarcane ethanol in Brazil for 2023.

As the focus shifts towards GHG emissions-centric policies, biofuel producers must ramp up their carbon intensity reduction efforts. In British Columbia, for instance, GHG emissions intensities decreased 50% for ethanol production and 65% for renewable diesel over a 12-year period. Over the next five years, similar improvements will be necessary across most of the biofuel industry.

IEA. CC BY 4.0.

Effective strategies for reducing emissions include careful feedstock selection; improving process energy efficiency; reducing the carbon intensity of biofuel production facilities; and employing innovative agricultural practices. In Brazil, for instance, sugarcane ethanol production utilises bioenergy from bagasse, a byproduct of sugar production, to reduce carbon intensity and enhance energy efficiency.

Internationally, establishing globally recognised GHG emissions intensity values can help improve trade, allowing regions with more low-carbon feedstocks to sell fuel to regions without. Almost 2 Mt CO_2 are currently captured every year from ethanol facilities, and plans are in place for another 20 facilities to capture nearly 15 Mt CO_2.

Transport sector GHG emissions reduction targets and prices

Region	Policy name	Target	Implementation date (s)	Price range
United States	Inflation Reduction Act	No target	2022	Up to USD 0.46/litre depending on GHG emissions intensity
State-level low-carbon fuel standards	California, Oregon and Washington low-carbon fuel standards	**California** - 20% reduction by 2030 **Oregon** - 20% reduction by 2030 **Washington** - 20% reduction by 2034	**California** - 2011 **Oregon** - 2016 **Washington** - 2023	**California** - USD 22-206/t CO_2 **Oregon** - USD 47-165/t CO_2
Brazil	RenovaBio	95 million carbon reduction credits by 2031	2020	USD 7-40/t CO_2
Canada	Clean Fuel Regulations	13% reduction by 2030	2023	TBD
Provincial-level low-carbon fuel standards	Greenhouse Gas Reduction (Renewable & Low-Carbon Fuel Requirements) Act	30% reduction by 2030	2013	USD 15-360/t CO_2
European Union	Renewable Energy Directive	14.5% reduction by 2030; optional 29% renewable energy share	2025	TBD
Germany		25% reduction by 2030	2016	USD 125-515/t CO_2
Sweden		Previously 66% reduction for diesel use and 28% reduction for gasoline use by 2030	2018	Maximum USD 670/t CO_2 former penalty rate

IEA. CC BY 4.0.

Chapter 3. Heat

Global forecast summary

Heat accounted for almost half of total final energy consumption and 38% of energy-related CO_2 emissions in 2022

Annual heat consumption expanded by 6% globally over 2017-2022. Renewable energy – excluding traditional uses of biomass – met only half of this increase, with its share in global heat consumption rising by only 2 percentage points to 13% in 2022.[1] More than two-thirds of global growth in renewable heat use was in the form of bioenergy (especially in industry) and renewable electricity (mainly in buildings).

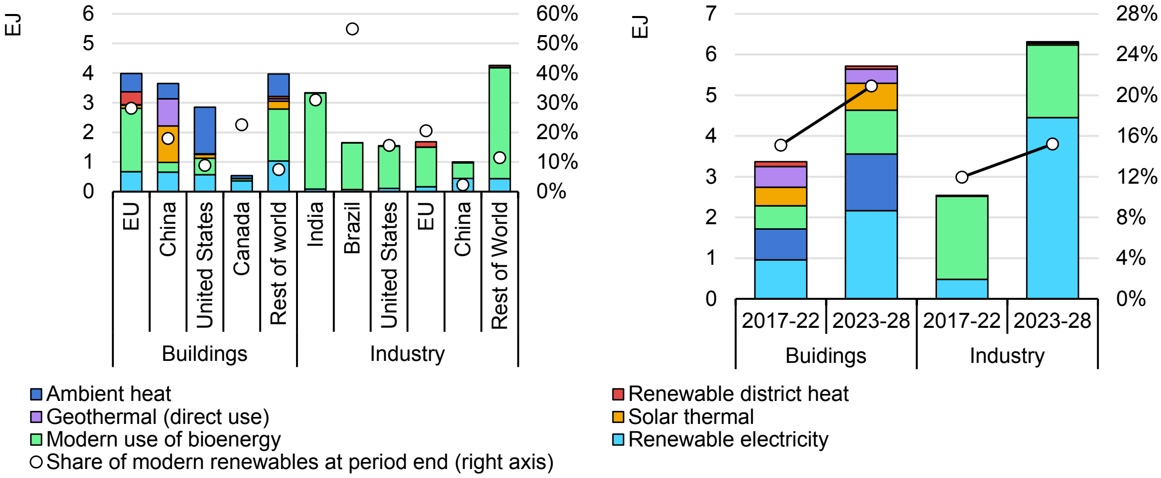
Industry sector renewable heat use increased the most in India over the last six years, owing chiefly to expansion of the sugar and ethanol industry that uses biomass residues, and – to a lesser extent – to the development of biomass briquette use in industrial boilers. The next-largest increases were in the European Union, thanks mainly to greater municipal waste and biomass use, and in China, with increasing reliance on electricity (a growing part of which is renewables-based) for process heat.

In the buildings sector, three-quarters of renewable heat developments in the past six years took place in China, the European Union and the United States.[2] Heat pump deployment has played a major role in all these markets, translating into rising consumption of both electricity and ambient heat for space and water heating. Large additional contributions also came from electric heating equipment and solar thermal and geothermal developments in China, and increased biomass boiler and stove use in the European Union.

[1] For the first time, the renewable heat outlook in this edition of the IEA renewable energy market report series includes regional estimates of ambient heat harnessed by heat pumps in the building sector. However, ambient heat from heat pumps in the industry sector is still not accounted for, due to limited data availability. Data presented in this report differ from the IEA World Energy Outlook 2023 dataset only by the inclusion of ambient heat estimates. Renewable heat consumption therefore includes the direct use of bioenergy and solar thermal and geothermal heat; ambient heat harnessed by heat pumps; the indirect use of power sector renewable energy through electricity used for heat generation; and the indirect use of renewable energy sources through district heat consumption. Heat pump contributions to renewable heat consumption are split into the renewable fraction of electricity they consume, and the ambient heat they transfer.
[2] In this report, heat consumption in the buildings sector covers space heating, water heating and cooking applications.

IEA. CC BY 4.0.

Renewable energy consumption and shares of heat demand in selected regions, 2022 (left), and global increases in renewable energy consumption, 2017-2028 (right)



IEA. CC BY 4.0.

Notes: EU=European Union. Ambient heat from heat pumps used in the industry sector is not accounted for due to limited data availability

Sources: IEA (2023), World Energy Outlook 2023; IEA (2023), Global Energy and Climate Model.

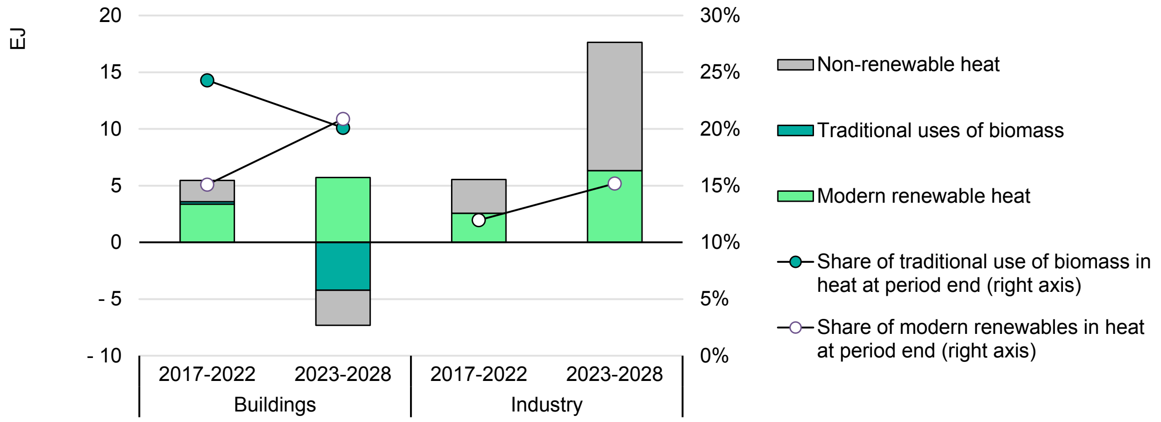
If fossil fuel use is not contained, the heat sector alone in 2023-2028 could consume more than one-fifth of the remaining carbon budget for an even chance to limit global warming to 1.5°C

Renewable heat consumption is expected to accelerate slightly over the outlook period, rising more than 40% (+12 EJ) globally during 2023-2028 – twice the increase of the previous six-year period. Nonetheless, this growth represents just 70% of the projected global increase in total heat demand, leading to rising fossil fuel consumption for heat and associated CO_2 emissions (+5%/+0.6 Gt CO_2 in annual emissions). Over 2023-2028, cumulative heat-related CO_2 emissions are anticipated to total 86 Gt CO_2 – more than one-fifth of the carbon budget remaining for a 50% likelihood of limiting global warming to 1.5°C.[3]

[3] This calculation is based on the IPCC estimate for the remaining carbon budget of 500 Gt CO_2 from the beginning of 2020 until the time of net zero global emissions, considering cumulative global CO_2 emissions of 112 Gt CO_2 over 2020-2022. Please note that the remaining carbon budget values depend on non-CO_2 greenhouse gas (GHG) mitigation strategies and are subject to uncertainty.

IEA. CC BY 4.0.

Global changes in heat consumption in the buildings and industry sectors, and shares of renewables in heat demand, 2017-2028



IEA. CC BY 4.0.

Note: ambient heat from heat pumps used in the industry sector is not accounted for due to limited data availability.

Sources: IEA (2023), World Energy Outlook 2023; IEA (2023), Global Energy and Climate Model.

Industry

Using more electricity for process heat expands renewable heat consumption, but not enough to curb fossil fuel use

Industrial heat demand is projected to expand 16% (+17.6 EJ) globally during 2023-2028, with China and India together accounting for more than half of the growth. Over this period, renewable heat developments are expected to represent just over one-third of additional heat demand, despite nearly 50% growth in consumption. The share of renewable energy sources in global industrial heat consumption is therefore anticipated to continue rising only slowly, from 12% in 2022 to 15% in 2028.

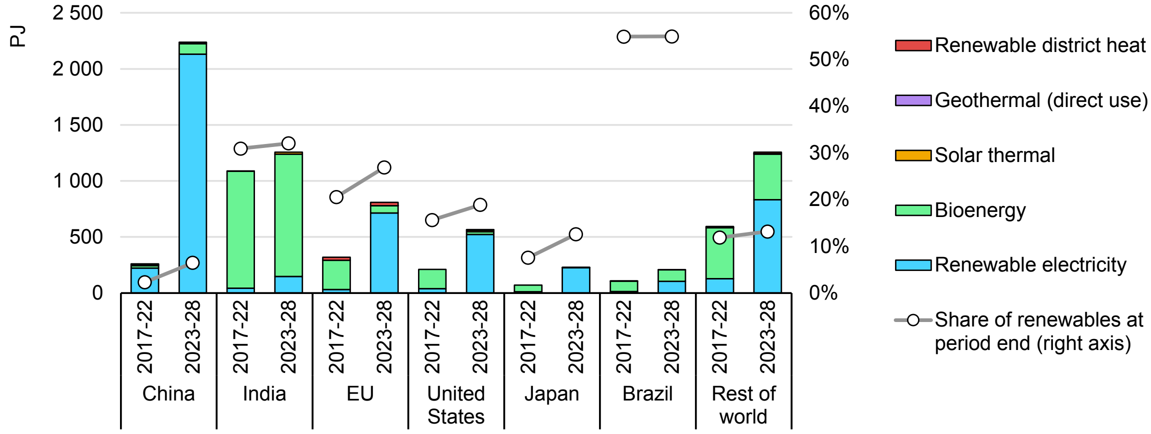
Renewable electricity makes by far the largest contribution to projected renewable heat developments in industry, representing 70% of the growth in annual consumption over the forecast period. This trend results from rising shares of renewables in electricity generation and, even more significantly, the tripling of electricity consumption for process heat.

This growing reliance on electricity for process heat (from 4% of global industrial heat consumption in 2022 to almost 11% in 2028) comes mostly from non-energy-intensive industries, with industrial heat pumps increasingly meeting temperature needs of up to 200°C, and from scrap metal recycling and aluminium industries, which use electric arc furnaces. China leads this trend, enlarging its use of renewable electricity for process heat more than fivefold over the outlook period,

IEA. CC BY 4.0.

representing almost half of global growth while the European Union, the United States and Japan together account for one-third of it.

Industry sector increases in renewable heat consumption and shares of renewables in heat demand, selected regions, 2017-2028



IEA. CC BY 4.0.

Notes: EU=European Union. Ambient heat from heat pumps used in the industry sector is not accounted for due to limited data availability.

Source: IEA (2023), World Energy Outlook 2023.

Remaining industry sector growth in renewable heat use comes essentially from rising bioenergy consumption (+1.8 EJ/+15%), which remains the largest renewable energy source globally, meeting around 10% of global industrial heat demand over the outlook period. More than 60% of this projected growth takes place in India, with Brazil, China, sub-Saharan Africa, Asia, and the European Union responsible for most of the remainder. However, global bioenergy developments essentially reflect expanding industrial activity – mostly in non-energy-intensive and non-metallic-mineral industries (e.g. cement) – rather than fuel switching, so the share of bioenergy in industrial heat consumption actually remains flat during the outlook period.

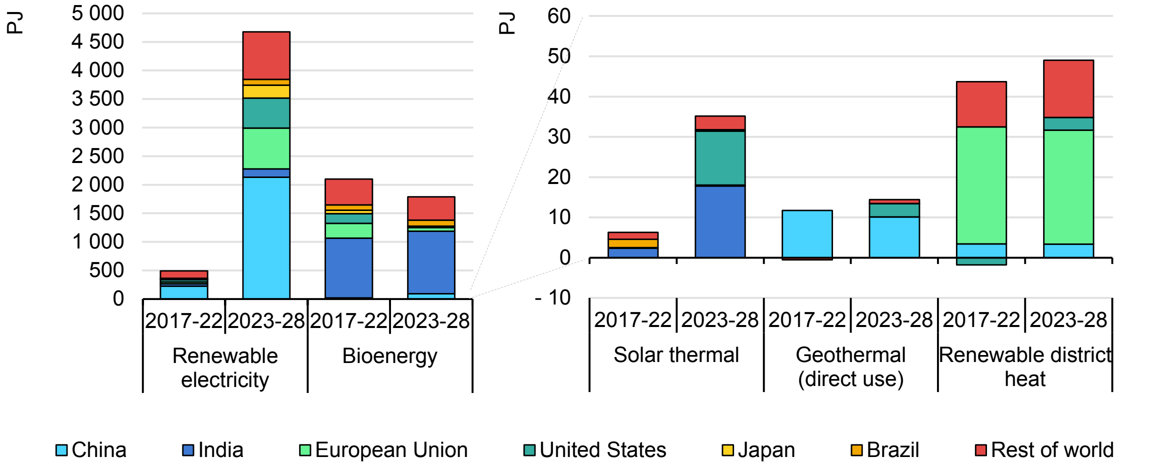
Meanwhile, higher consumption is expected for solar thermal heat (up more than 160%/+35 PJ) and geothermal heat (up nearly 60%/+14 PJ) in industrial processes. The global solar industrial heat market maintained its dynamism in 2022, with at least 30 MW of new projects starting operation, mostly in Europe, China and the United States, leading to total cumulative global capacity of more than 850 MW. Furthermore, more than 300 MW of additional capacity are expected to start operation during 2023-2026.

Yet, the combined projected solar thermal and geothermal contribution remains marginal overall, representing less than 1% of industry sector growth in renewable heat consumption. The strong potential of these technologies to decarbonise low- and medium-temperature processes, commonly found in the food and beverage,

IEA. CC BY 4.0.

textile, chemical and mining industries, for instance, remains massively untapped in this outlook due to low awareness and a lack of local expertise and policy support. Energy service companies (ESCOs) are expected to play an increasingly important role in projected developments, especially for large industrial process heat projects.

Industry sector increases in renewable heat consumption by source, selected regions, 2017-2028



IEA. CC BY 4.0.

Notes: Ambient heat from heat pumps used in the industry sector is not accounted for due to limited data availability.

Source: IEA (2023), World Energy Outlook 2023.

Buildings

Rising shares of renewables in electricity and heat pump and electric boiler deployment boost renewable heat consumption in China, the European Union and the United States

Global heat consumption in the buildings sector is expected to remain flat during 2023-2028, as increases in sub-Saharan Africa, Europe,[4] the Caspian region and most of Southeast Asia (resulting from population growth, changes in living standards and greater service sector activity) offset declines in the United States, India, China, Japan and Indonesia (owing to energy efficiency improvements).[5] Modern uses of renewable energy sources for space and water heating, as well as for cooking, are projected to expand nearly 40% in the meantime, raising the

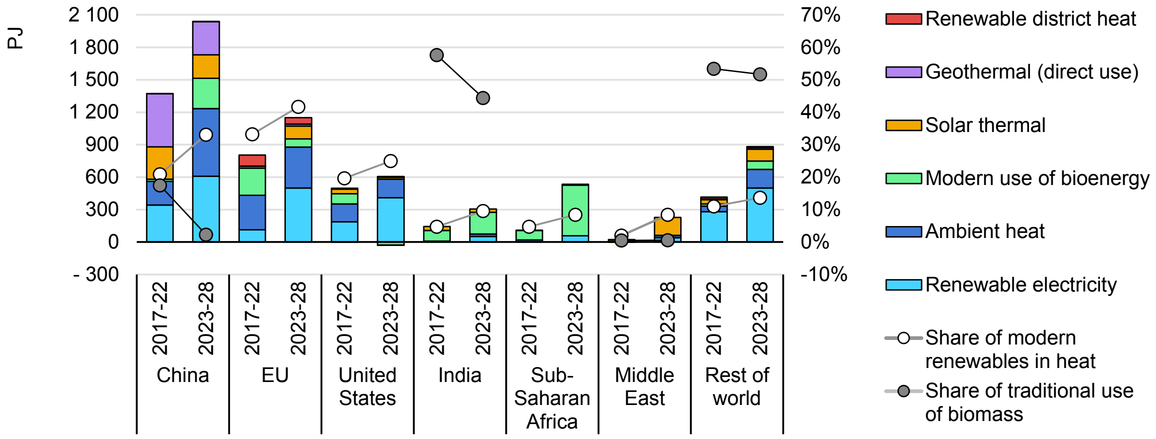
[4] The progressive erosion of some energy conservation measures individuals and enterprises adopted during the energy crisis is also expected to raise buildings sector heat demand in Europe.

[5] Heat consumption corresponds mostly to water heating and cooking in India, Indonesia, sub-Saharan Africa and Southeast Asia, while space heating represents a major part of demand in other regions.

IEA. CC BY 4.0.

share of renewables in buildings sector heat consumption from 15% in 2023 to 21% in 2028, and displacing 5.7 EJ of fossil fuel consumption in 2028.

Buildings sector increases in renewable heat consumption and shares of modern and traditional uses of renewables in heat demand, selected regions, 2017-2028



IEA. CC BY 4.0.

Notes: EU=European Union

Sources: IEA (2023), World Energy Outlook 2023; IEA (2023), Global Energy and Climate Model.

Renewable electricity remains the fastest-growing renewable heat source in buildings during the outlook period, its use expanding by two-thirds globally (+2.2 EJ) and contributing almost 40% of the sectoral increase in renewable heat consumption. China, the European Union and the United States lead this trend, making up 70% of global growth in renewable electricity use for heat in buildings. In contrast with the industry sector, three-quarters of this growth results from a rising share of renewables in power generation, while the rest comes from the deployment of new electric heaters, boilers and heat pumps.

Boosted by strong policy support in the context of high energy prices, global heat pump sales rose 11% in 2022. The European market experienced record 39% growth with 3 million new units installed, while in the United States heat pump purchases exceeded those of gas furnaces. The Chinese market – the world's largest heat pump market – remained stable, however, due to the global economic slowdown.

Heat pumps typically use three to five times less electricity than conventional resistive electric heaters and boilers for a given heat output. While heat pumps consumed less than 15% of the electricity used for heat in buildings globally in 2022, their deployment accounts for one-third of the global increase in electricity use over 2023-2028, and nearly one-quarter of the growth in renewable electricity use.

IEA. CC BY 4.0.

Furthermore, heat pumps participate in renewable heat uptake not only by using electricity but by harnessing ambient heat, which represents one-quarter of global growth in renewable heat consumption in buildings during 2023-2028 – the second-largest increase (+1.4 EJ) after renewable electricity. This expanding ambient heat contribution comes primarily from China, followed by the European Union and the United States, owing to strong policy support (investment grants, fiscal incentives and loans) introduced in 2021.

Since announcement of the REPowerEU plan's heat pump targets, the heat pump industry has been preparing to scale up, with nearly EUR 5 billion of investments in EU manufacturing capacity and logistics announced for 2023-2026.

However, bioenergy remains the largest renewable heat source in buildings globally by 2028, accounting for one-fifth (1.1 EJ) of modern renewable heat developments in the sector over the outlook period. Modern bioenergy use in buildings expands most notably in sub-Saharan Africa (+0.5 EJ), China (+0.3 EJ) and India (+0.2 EJ), where improved biomass cookstoves and heating stoves are replacing traditional uses of biomass. In fact, the latter drops 17% (-4.2 EJ) globally during 2023-2028, owing essentially to urbanisation trends and policy intervention, driven partly by environmental health considerations in China and India.

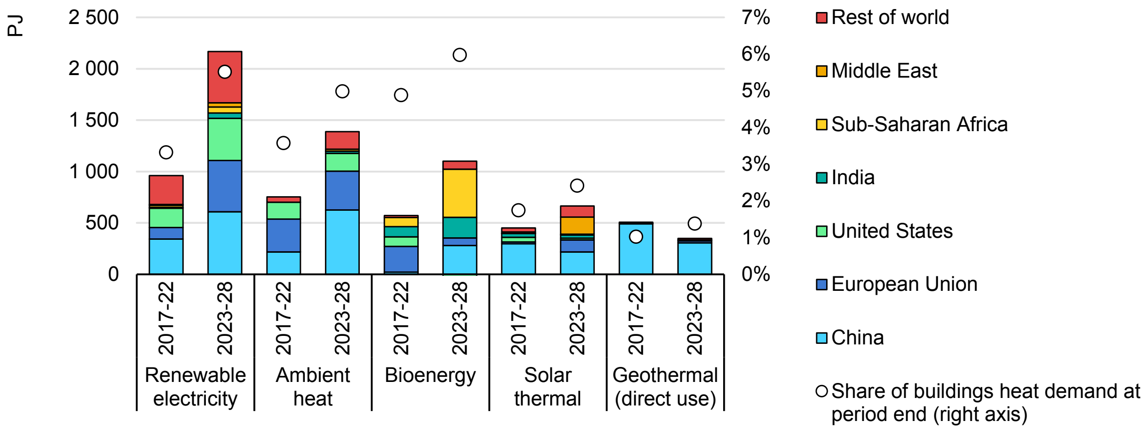
Sustained sales of wood chip and pellet stoves and boilers in the European Union, especially in Italy, France and Germany, contribute slightly (+0.07 EJ) to the bioenergy outlook. However, high investment costs for automated systems, rising biomass fuel prices, technical requirements (e.g. space for fuel storage) and supply chain tensions hinder faster deployment. In 2022, the United States and Europe – the world's largest wood pellet consumer – were already facing a supply crunch for wood pellets as demand surged.

Solar thermal heat consumption in buildings is projected to increase nearly 40% (+0.7 EJ) during 2023-2028. Despite domestic market contraction since 2020 due to Covid-19 lockdowns (sales declined 12% year-on-year in 2022), China continues to dominate global solar thermal developments, being responsible for one-third of consumption growth during the outlook period, with market dynamism shifting slightly towards large-scale segments. The Middle East region (where water desalination applications drive growth) and the European Union (where capacity additions grew 12% year-on-year in 2022) are the next-largest solar thermal markets, together contributing more than 40% of the increase in solar thermal heat use.

Meanwhile, developments in the direct use of geothermal heat represent 6% (0.35 EJ) of projected growth in renewable heat consumption in buildings globally. China, which was responsible for almost 90% of global direct geothermal heat consumption in 2022, is anticipated to continue leading growth in similar proportions, with progress outside of China coming mostly from the European Union.

IEA. CC BY 4.0.

Buildings sector increases in renewable heat consumption and shares in heat demand by source, selected regions, 2017-2028



IEA. CC BY 4.0.

Sources: IEA (2023), World Energy Outlook 2023; IEA (2023), Global Energy and Climate Model.

District heating decarbonisation potential remains largely untapped

District heating networks met nearly 7% of global heat demand from the buildings and industry sectors in 2022. Representing three-quarters of global district heat supply were the world's two largest district heating markets, China (relying essentially on coal) and Russia (using mainly gas). The amount of heat supplied by district heating networks is projected to expand 9% (+1.3 EJ) globally during the outlook period, with more than 90% of the growth occurring in China.

District heating networks offer considerable potential for renewable heat integration. For instance, renewable energy sources can be deployed in district heating through waste-to-heat technology and biomass co-firing, large-scale heat pumps, and solar thermal systems. The latter is garnering rising interest in China as well as in a number of European countries, with 400-500 MW_{th} of projects in development in 2023. In addition, the lower operating temperatures, integrated thermal storage and advanced metering, control and optimisation strategies of fourth- and fifth-generation district heating and cooling networks and local ambient heat loops can further facilitate renewable energy integration.

Nevertheless, the share of renewables in global district heating supplies is projected to remain stable at just below 6% during 2023-2028, resulting in less than 0.2 EJ of additional renewable district heat consumption. The European Union shows the most promise in expanding renewable district heat use, especially in the buildings sector, with new network developments as well as fuel switching and the integration of renewable energy sources in existing plants.

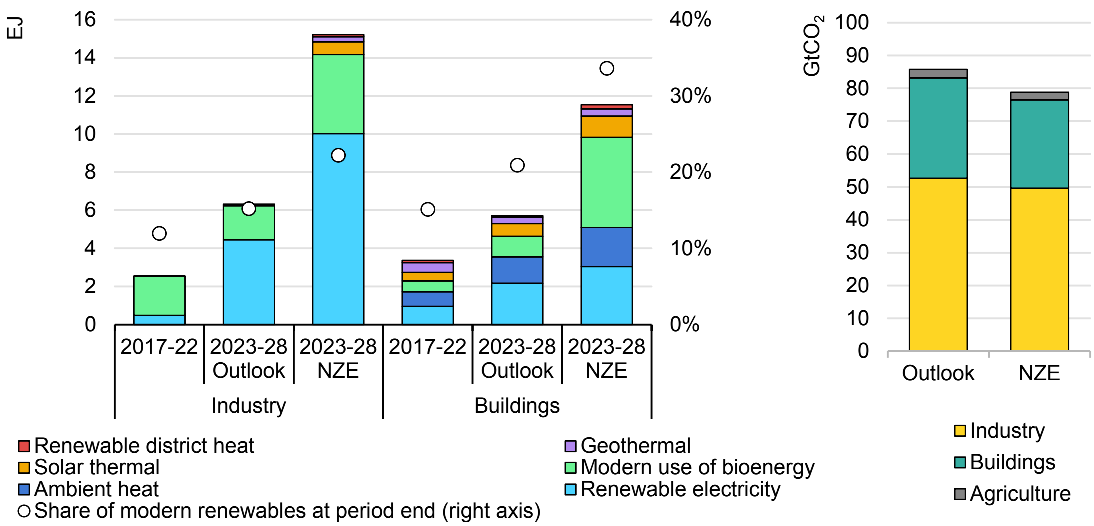
IEA. CC BY 4.0.

Net Zero Emissions by 2050 Scenario tracking

Excluding ambient heat, the outlook for renewable heat developments for 2023-2028 has been revised up 17% from the *Renewables 2022* projection, with the buildings and industry sectors contributing in similar proportions to this revision. Yet, projected renewable heat developments by 2028 are still largely insufficient to displace fossil fuel use significantly and put the world on track to meet Paris Agreement ambitions.

To align with IEA Net Zero Scenario targets, global renewable heat consumption would have to advance 2.2 times more quickly, while wide-scale sufficiency-oriented behavioural and social change,[6] and much larger energy and material efficiency improvements, would be required to reduce global heat demand by more than 2% during 2023-2028.

Increases in global renewable heat consumption and shares of renewables in heat demand, 2017-2028 (left), and global cumulative heat-related CO_2 emissions, 2023-2028 (right) in IEA outlook and Net Zero Scenario



IEA. CC BY 4.0.

Notes: NZE = IEA Net Zero Emissions by 2050 Scenario. Ambient heat from heat pumps used in the industry sector is not accounted for due to limited data availability. Heat-related cumulative CO_2 emissions over 2023-2028 in the outlook and Net Zero Scenario correspond respectively to approximately 22% and 20% of the remaining carbon budget (RCB) from the beginning of 2023 for a 50% likelihood of limiting warming to 1.5°C. This calculation is based on the IPCC RCB estimate of 500 Gt CO_2 from the beginning of 2020 until the time of net zero global emissions, considering cumulative global CO_2 emissions of 112 Gt CO_2 over 2020-2022. Please note that these values depend on non-CO_2 greenhouse gas mitigation strategies and are subject to uncertainty.

Sources: IEA (2023), World Energy Outlook 2023; IEA (2023), Global Energy and Climate Model.

[6] Sufficiency corresponds to the tailoring and scaling of infrastructure, technology choices and behaviours to fundamental needs while selectively avoiding nonessential resource-intensive services and consumption patterns to avoid demand for energy, materials, land and water. Energy sufficiency policies and actions aim to allow affordable access to energy to meet everyone's needs and fair access to meet their energy wants, while keeping the impacts of energy use within planetary boundaries.

IEA. CC BY 4.0.

In the IEA Net Zero Scenario, industrial consumption of bioenergy and renewable electricity for heat both increase 2.3 times faster than in our outlook, resulting in the largest discrepancy in absolute value between the two trajectories. Meanwhile, solar thermal and geothermal heat consumption in industry in the Net Zero Scenario expands almost 20 times faster than currently projected.

For the buildings sector, the Net Zero Scenario outlines a substantial 21% reduction in heat demand during 2023-2028 and relies on much stronger (4.4 times faster) modern bioenergy development, mostly to replace the traditional use of biomass, which is assumed to decline 70% (-17 EJ). Faster heat pump deployment in the Net Zero Scenario also prompts renewable electricity use and ambient heat consumption to increase more than 40% more quickly than in our outlook. Meeting the scenario's trajectory would require that heat pumps make up nearly 40% of global heating equipment sales by 2028 – more than double our current outlook amount, and four times more than in 2022.

Meanwhile, annual solar thermal heat consumption expands twice as quickly in the Net Zero Scenario as in our outlook. In the scenario, these renewable energy developments in the buildings sector are partly stimulated by a global ban on sales of new fossil fuel-fired boilers in 2025.

Finally, while the amount of heat supplied by district networks is assumed to decline slightly as building stock efficiency increases, the share of renewables in district heat supplies is assumed to exceed 8% by 2028.

Overall, the share of renewables in heat consumption rises to 22% in industry and 34% in buildings by 2028 in the Net Zero Scenario, while cumulative heat-related CO_2 emissions over 2023-2028 are 8% lower than in our outlook.

Technology, market and policy trends

Policy

Governments are raising renewable heat targets

At the end of 2022, 46 countries had a renewable energy target for heating and cooling, with 3 aiming for 100% renewables. Most of these countries are EU members, as the bloc updated its energy policy frameworks significantly in 2023 in response to the energy crisis.

Building on the 2022 REPowerEU plan, in September 2023 the European Parliament approved the revised Renewable Energy Directive (RED III), which had been proposed in the Fit-for-55 package adopted by the European Commission in 2021. The revised directive includes a new binding target of 42.5% renewable energy in Europe's energy mix by 2030, with an indicative commitment

IEA. CC BY 4.0.

of 45%. Targets for heating and cooling have been revised upwards with binding renewable share increases of at least 0.8 percentage points per year at the national level until 2026 and 1.1% from 2026 to 2030, complemented by indicative country-specific top-up rates to reach an average annual increase of 1.8 percentage points at the EU level.

The revised directive also includes indicative targets of at least 49% renewable energy in the buildings sector by 2030 as well as 1.6-percentage-point average annual increases in the share of renewables in the industry sector for 2021-2025 and 2026-2030, and 2.2-percentage-point average annual increases during 2021-2030 for district heating and cooling. In addition, member states agreed that 42% of the hydrogen used in industry should come from renewable fuels of nonbiological origin by 2030.

Furthermore, RED III strengthens the sustainability criteria for using biomass for energy in line with the principle of cascading use of biomass, with a focus on adapting support schemes to limit the use of primary wood for energy. Member countries are expected to submit their draft action plans to conform with the updated directive by June 2024.

The European Union also strengthened its Energy Efficiency Directive in 2023, adding a new binding target to reduce final energy consumption by at least 11.7% compared with the reference scenario by 2030. Accordingly, member countries will be required to achieve average annual energy savings of 1.49% from 2024 to 2030, up from the 2021-2023 requirement of 0.8%.[7] Additionally, the revised Energy Efficiency Directive extends the annual 3% building renovation obligation to all public buildings, with these energy saving targets and renovation obligations also expected to stimulate heat pump deployment.

China also implemented new targets in 2022 with enforcement of its 14th Five-Year Plan for Building Energy Conservation and Green Building Development, which introduces the country's first binding national energy-efficiency standard. The plan, which applies to new buildings, stipulates that onsite renewables meet 8% of energy demand in buildings in urban areas, and that the share of electricity in buildings sector energy demand exceed 55% by 2025. It also aims for geothermal heat to cover 100 million square metres of floor space. In addition, the country's 2022 Work Plan on Energy Saving and Environment Protection in Government and Public Buildings requires that new heat pump installations meet the heating needs of 2 million square metres of public building floor space.

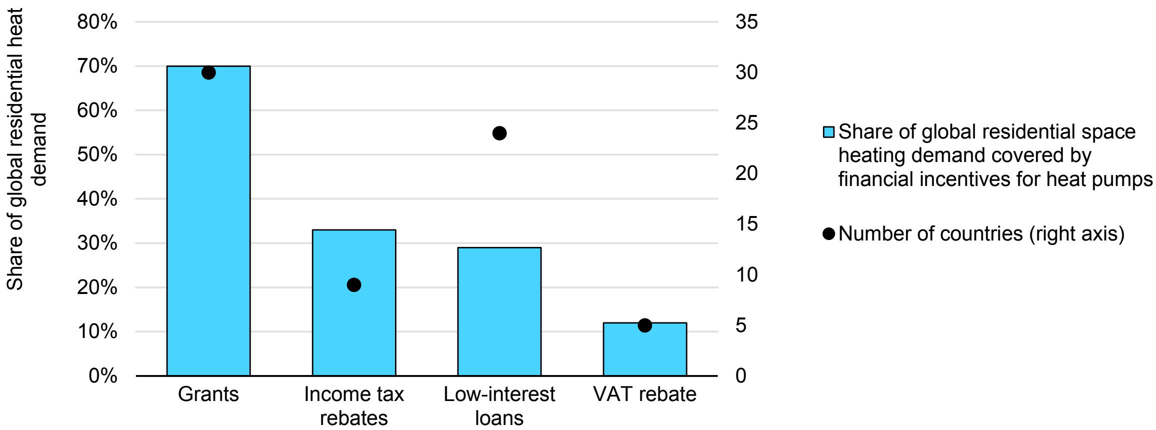
[7] Annual energy savings requirements for member states will increase gradually to 1.3% over 2024-2025, 1.5% over 2026-2027 and 1.9% for 2028 onwards, resulting in 1.49% average annual energy savings from 2024 to 2030.

IEA. CC BY 4.0.

Financial incentives and fossil fuel bans are increasingly supporting renewable heat uptake

The recent surge in heat pump sales was driven not only by a more favourable gas-to-electricity price ratio in many regions and the anticipation that gas prices would remain high, but also notably by the implementation of strong financial incentives (i.e. grants, tax rebates and low-interest loans). Such incentives are currently available in more than 30 countries worldwide, covering more than 70% of global heating demand for buildings. Many of these incentives were introduced or strengthened in 2022.

Global coverage of financial support schemes for heat pumps, 2022



IEA. CC BY 4.0.

Source: IEA (2023), The Future of Heat Pumps.

Since the beginning of 2023, subsidy levels for heat pumps and renewables-based heating systems have been increased in Austria, Ireland, Poland and the United States. In Europe, with sales totalling nearly 3 million units in 2022, the heat pump sector benefited from more than EUR 9 billion in policy support through subsidies, tax credits and reduced VAT, in addition to specific loan schemes.[8] Assuming support schemes remain unchanged, and considering projected heat pump deployment, this value could more than double by 2028.

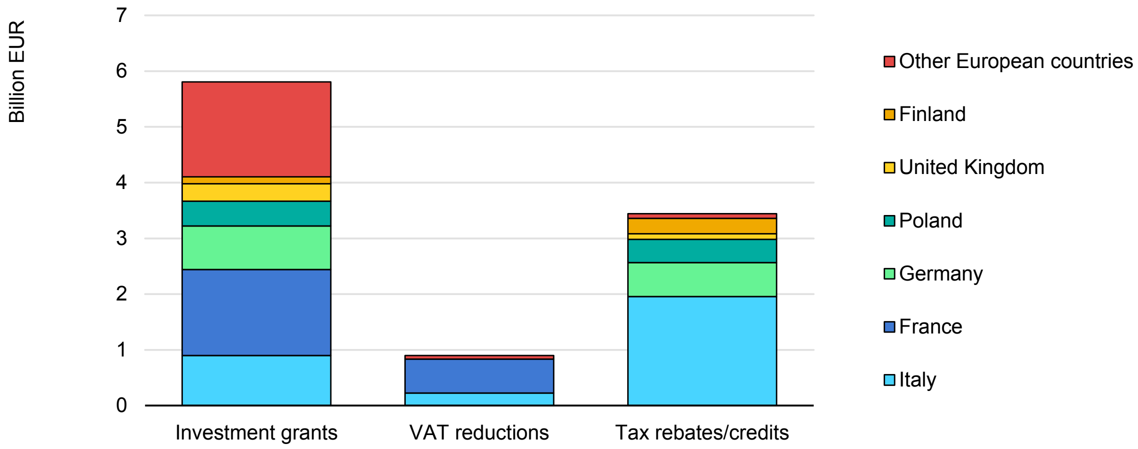
In the interest of equitability, many of the support schemes available to households are designed to offer greater support to low-income groups. One-stop-shop policy approaches are particularly important to help make the most effective use of

[8] This estimate does not account for policy support provided for building retrofits and the replacement of radiators and heat distribution systems, although such upgrades also benefit the heat pump sector indirectly by improving building compatibility with this technology.

IEA. CC BY 4.0.

support by building trust with end users, helping them select the most appropriate renewable heat technology and design for their purpose, financing the installation and ensuring its quality.

Estimated government support in the form of subsidies and fiscal incentives for heat pumps in selected European countries, 2022



IEA. CC BY 4.0.

Notes: "Other European countries" includes Austria, Belgium, Switzerland, Czechia, Spain, Hungary, Ireland, Lithuania, the Netherlands, Norway, Portugal, Sweden and Slovakia. Government spending estimates are based on national heat pump sales in 2022 by technology and segment (as per EHPA) and the design of available national support schemes, assuming typical investment costs when necessary. Although not accounted for here, various countries also offer support in the form of low-interest loans (e.g. the Netherlands, Poland).

Regulatory measures such as renewable heat obligations and fossil fuel bans are also developing in the buildings sector, predominantly in Europe and North America. In fact, 17 European countries had implemented or announced bans on fossil fuel-fired boiler installations by the end of 2022. Some bans target installations in new buildings only, while others also cover replacements in existing buildings.

For instance, France's new building code introduced a national ban on gas boilers in new single-family homes starting in 2022 and in new multifamily buildings from 2025, while a recent decree limiting the CO_2 intensity of heating systems implicitly banned the installation of oil- and coal-fired boilers in both new and existing buildings as of 2022. In 2023, Germany announced a 65% renewable heat obligation for new buildings in new housing development areas from 2024, effectively ruling out the use of standalone fossil fuel-based boilers in those areas.

Fossil fuel boiler bans are also gaining momentum in the United States and Canada, although they are being passed at only the regional, state or municipal level (e.g. New York State, Boston, San Francisco, Montreal). Such explicit or de-facto fossil fuel bans and renewable heat obligations in the buildings and industry sectors are pivotal to accelerate the conversion to renewable heat while limiting public spending by mobilising end-user funds.

IEA. CC BY 4.0.

In the industry sector, however, renewable heat regulations remain scarce: in 2022, only 9 countries had renewable energy mandates in place for industry and just 12 had made renewable energy financial support available for the sector.

In December 2022, India amended its Energy Conservation Act to provide for a carbon credit trading scheme. It also empowered the central government to require designated consumers (e.g. the mining, steel, cement, textile and chemical industries) to source a minimum share of their energy consumption from non-fossil fuels.

Industrial policies are increasingly part of renewable energy strategies

While many renewable heat policies support renewable energy adoption on the demand side, supply chain strengthening and manufacturing capacity scaleup are also necessary to accelerate renewable heat uptake. Industrial policies are therefore becoming essential components of renewable energy strategies in some regions, as they generally aim to facilitate permitting for manufacturing projects, incentivise investment and support training programmes for technology designers, workers and installers.

In November 2022, for instance, the United States announced a USD 250-million investment to boost domestic electric heat pump manufacturing, funded by the Inflation Reduction Act and leveraging the Defense Production Act. More recently, following the launch of the Green Deal Industrial Plan in February 2023, the European Commission proposed the Net-Zero Industry Act (NZIA) in March to increase European manufacturing capacity by facilitating investment and developing dedicated training programmes for low-carbon technologies, including heat pumps[9] and geothermal and solar thermal technologies.

Solar PV could become a competitive renewable energy option for water heating

The tenfold drop in solar PV module costs since 2010 has made solar photovoltaic electricity a viable energy source for water heating applications. Hot water systems using PV-derived electricity can consist simply of a DC-powered resistance heater inside a hot water tank connected to dedicated solar PV panels (without the need for an inverter). For backup, an AC-powered element connected to the grid can also be inserted into the tank for times when solar resources are insufficient.

[9] The NZIA targets 31 GW of annual EU heat pump manufacturing capacity by 2030, up from an estimated 22 GW in 2022.

IEA. CC BY 4.0.

These systems are generally referred to as PV2heat. A more advanced form of this system can integrate an electronic control system (known as a solar diverter[10]) that redirects excess generation from a non-dedicated domestic solar PV system to an electric immersion water heater or an electric heat pump water heater for self-consumption.

Compared with traditional solar thermal installations, PV-based water heating systems are relatively simple to install, requiring mostly wiring instead of insulated pipes. In fact, commercial packages such as plug-and-play and do-it-yourself kits are already available in some markets. These PV-based hot water systems also have low sensitivity to external temperatures and, thanks to the absence of moving parts, require very limited maintenance and have a relatively long lifetime (solar diverters can last more than 10 years, and PV modules more than 25). However, while they offer more flexibility to install the hot water tank further from the collectors with minimal energy losses, PV-based systems require nearly three times more collector area than traditional solar thermal systems for equivalent heat output, unless they use a heat pump.

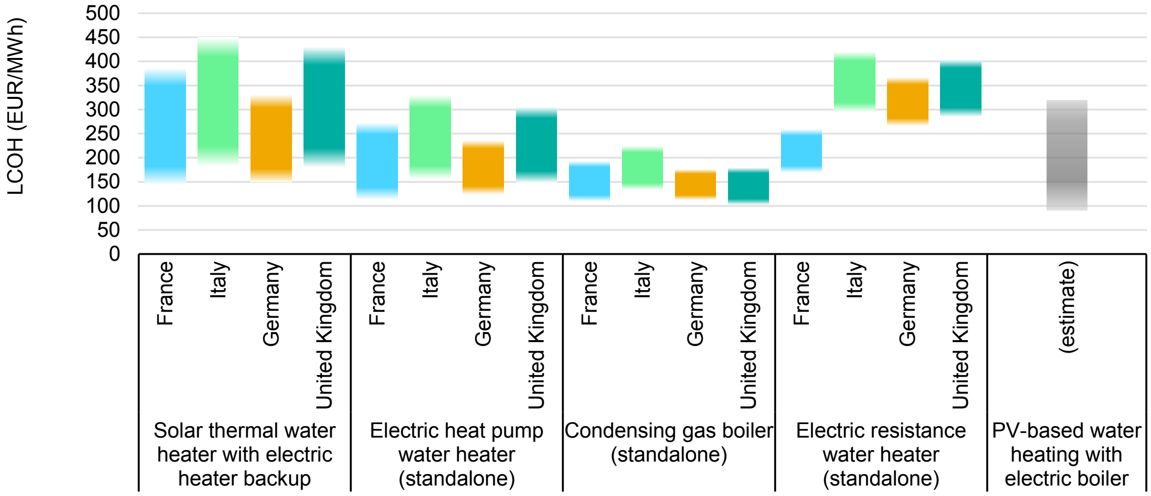
As PV-based water heating systems are still relatively new to the market, research is ongoing to assess the environmental, social and economic benefits associated with their deployment. As commercial solutions have similar investment costs as traditional solar thermal water heaters in some markets, very low operating and maintenance costs, and a relatively long lifetime, PV-based water heating has the potential to become cost-competitive with existing sanitary hot water technologies (including heat pumps and gas boilers) in many regions. For new PV-based systems, installation makes up a large portion of the total cost, but this expense could be reduced through equipment standardisation and the development of plug-in solutions.

Furthermore, policy schemes for self-consumption and net metering can significantly influence the design, sizing and economic attractiveness of new PV-based water heating systems. For instance, the absence of net-metering schemes may steer consumers towards smaller solar PV installations or larger hot water storage to maximise self-consumption, while net-metering schemes and remuneration for excess generation would incentivise larger PV installations, potentially covering a greater fraction of both space and water heating and electricity demand (if excess generation is remunerated at a lower rate than the retail electricity price).

[10] Solar power diverters are sometimes also referred to as solar PV optimisers, immersion diverters, or immersion optimisers. Their cost is typically in the range of EUR 300-500, and they can be added to existing solar PV installations.

IEA. CC BY 4.0.

Levelised cost of heat for small sanitary hot water systems in selected countries, 2022



IEA. CC BY 4.0.

Notes: LCOH = levelised cost of heat. Calculations are based on national average household gas and electricity prices for 2022. Insolation values are for capital cities (Paris, Rome, Berlin and London). Investment costs correspond to household systems for 3-4 people, based on typical market prices and excluding policy support. For both solar thermal and solar PV-based systems, the solar fraction is assumed to cover 50% of annual sanitary hot water demand. The solar PV collector area is assumed to be sized accordingly (2 to 4 modules of 400 Wp depending on the country). The calculation assumes a seasonal performance factor of 2.8 for heat pump water heaters. The levelised cost of heating is calculated based on national average household hot water demand over the assumed lifetime of each technology (17-30 years for solar thermal water heaters; 20-26 years for PV2heat systems, assuming replacement of the backup electric boiler and power diverter after 12 years; 14-20 years for standalone heat pump water heaters; 12-17 years for standalone condensing gas boilers; and 9-14 years for standalone electric water heaters). A discount rate of 2% is applied. For the sake of simplicity, this calculation assumes neither net metering nor remuneration for excess solar PV generation, although such schemes could significantly improve the economic case of solar PV-based systems. The LCOH range calculated for solar PV-based systems reflects a preliminary theoretical estimate for the four countries shown in the figure. Actual values can be significantly influenced by hot water consumption profiles, water storage capacity and, when they are used, by the control and optimisation strategies of solar diverters.

In large residential heat markets, however, water heating represents a relatively small fraction of a household's energy bill, and the economic savings that can potentially be achieved – sometimes only after a relatively long payback period – may not suffice to stimulate consumers to switch to renewables-based water heating technologies. Information and awareness-raising campaigns, training programmes for installers to build local expertise, and the development of equipment certification systems will therefore also be key to harness the environmental and energy security benefits of PV-based water heating.

Thermal energy storage provided by hot water tanks helps integrate renewable energy

Water heating technologies with built-in or associated hot water tanks, such as PV-based systems, also add value from an energy system perspective. Representing about 13% of total energy demand in buildings globally, sanitary hot water preparation offers significant potential for demand-side flexibility thanks to the storage capacity of hot water tanks. In 2022, total utility-scale energy storage

IEA. CC BY 4.0.

in the European Union was estimated at roughly 9 GWh – less than the usable heat stored in just one million medium-sized hot water tanks.[11]

The cost of using hot water tanks for storage is an order of magnitude below that of lithium batteries, and the critical mineral requirements are low in comparison. Such distributed thermal storage units, already installed in many dwellings, could also be deployed more widely with new water heating systems to facilitate VRE integration considerably.

[11] Assuming the tanks have a capacity of 180 litres, and considering the energy required to raise the water temperature from 15°C to 60°C. For comparison, there were 198 million households in the European Union in 2022.

IEA. CC BY 4.0.

Special section: Biogas and biomethane

Introduction

For the first time in the IEA's renewable energy market report series, we are dedicating a special section to biogas. Biogas production began to grow in the 1990s and has been rising since then, but policy support has surged strongly in the last two years owing to a combination of factors. First, with energy security concerns caused by Russia's invasion of Ukraine and the subsequent energy crisis, biogas is now regarded as a domestic energy source that can reduce dependency on natural gas imports and support energy security in many countries.

Second, in view of the urgent need to limit global temperature rise to 1.5°C, countries have begun to view biogas as a ready-to-use technology that can help accelerate decarbonisation in the short term, and they are therefore developing specific policies that include biogas as a key component in their energy transition strategies.

Along with targeted policies, market conditions are stimulating biogas use. While combined heat and power units generally run on biogas, other gas demand markets (e.g. gas utilities, and the industry and transport sectors) will require the use of biomethane, a purified biogas with high concentrations of methane, similar in quality to natural gas and thus interchangeable with it. Biomethane is also known as renewable natural gas (RNG) in the United States and Canada, bio-compressed natural gas or compressed biogas (bio-CNG or CBG) in India and bio-natural gas (BNG) in China.

Apart from being a clean domestic energy source, biogases (biogas and biomethane) provide other benefits. For instance, biomethane can be used to decarbonise hard-to-electrify sectors such as transport and industry. Both biogas and biomethane use reduces not only CO_2 emissions from fossil fuel combustion but also, when correctly managed, methane emissions from the waste and agriculture/livestock sectors (responsible for 60% of anthropogenic global methane emissions). This advantage aligns well with the emissions reduction objectives of the Global Methane Pledge launched in 2021 and signed by 155 countries (as of January 2024).

Thus, using biogas and biomethane helps build a circular economy around residue and waste valorisation, contributes to rural economic development and creates

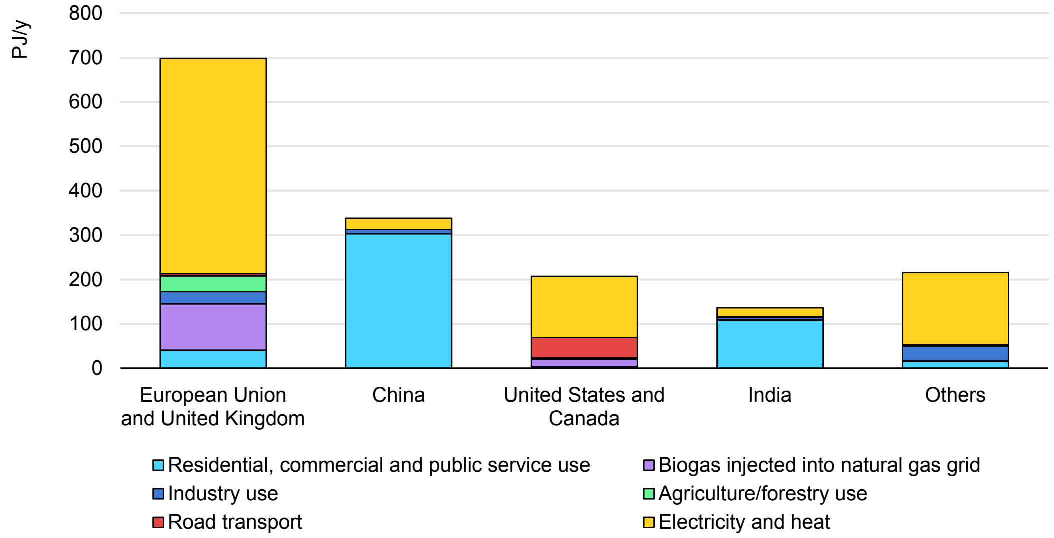
IEA. CC BY 4.0.

employment. Plus, producing natural fertilisers as a coproduct of biogas and biomethane production can augment farmers' income and help re-establish soil health by eliminating certain environmental impacts related to untreated manure use. Biogas can also be used for clean cooking in developing countries.

Biogas today

Combined global biogas and biomethane production reached more than 1.6 EJ in 2022 – a 17% increase from 2017. Almost half of the production is based in Europe, with Germany alone meeting almost 20% of global consumption. Another 21% is produced in China, followed by the United States (12%) and India (9%). However, regional and country variations can be significant. Depending on the characteristics of each energy system, biogas/biomethane development is supported differently by different governments to complement the rest of their energy matrix.

Main uses of biogases for selected countries and regions, 2021



IEA. CC BY 4.0.

In **China**, household digesters were developed some decades ago to provide clean energy for cooking and residential use in rural areas (accounting for around 300 000 TJ/year of biogas production). Impressively, thanks to investment support from the Chinese Rural Household Biogas State Debt Project beginning in 2003, almost 42 million household digesters had been installed by 2015. In 2015, however, government policy shifted towards engineered plants for combined heat and power generation, with capital aid and feed-in tariffs being offered.

More recently, since 2019 the Chinese government has been steering a biogas industry transition, investing in large-scale (>10 mcm/year) bio-natural gas (BNG, biomethane) projects. These plants would use rural and urban waste feedstocks

IEA. CC BY 4.0.

in an integrated manner to produce electricity and gas to inject into the grid. The Guiding Opinions on Promoting the Industrialisation of BNG from 2019 set ambitious targets (10 bcm by 2025 and 20 bcm by 2030). Although production expanded more slowly than planned during 2010-2020, new regulations supporting biogas deployment have come into force in the last two years.

For instance, China's 14th Five-Year Plan for Renewable Energy Development (2021-2025) focuses on large-scale projects for grid injection to diversify applications, with subsidies still under discussion. A new national standard for plant construction was released in 2022. While most of China's biogas/biomethane is produced from manure, there is growing interest in using large rural facilities to also incorporate urban organic waste as feedstock.

India also has considerable small-scale household biogas production in rural areas lacking grid access, with biogas being an important energy source for clean cooking and lighting. Through its One Nation One Gas Grid programme, India plans to enlarge the role of natural gas in its economy by investing in new gas infrastructure, aiming to raise the share of natural gas in the energy sector to 15% by 2030 (from 6.2% in 2022). India has recently announced a blending mandate of 5% biomethane in compressed natural gas (CNG) for transport and in piped natural gas for domestic use from 2028, growing each year from 1% in FY 2025-2026.

The Sustainable Alternative Towards Affordable Transportation (SATAT) programme, launched in 2018, has very ambitious goals for producing biomethane for transport and industrial fuels. CBG is delivered in pressurised cylinders called cascades in India. India's already-extensive and growing fleet of gas-powered buses, trucks and light-duty vehicles (12% of passenger vehicles in 2023), including taxis and rickshaws, could benefit from SATAT programme support for CBG production, as it will offer another fuel to choose from, at a government-controlled price and with a smaller carbon footprint.

Meanwhile, other schemes such as the 2022 National Biogas Programme cover the use of biogas for power and thermal energy generation. This policy provide financial aid, fixed feed-in tariffs and tax exemptions for bioCNG, taking into account the particularities of rural and remote areas. India has great feedstock potential, in the form of agricultural residues, manure, municipal organic waste and sewage sludge. However, feedstock supply chains (e.g. for waste collection or urban wastewater treatment) will require further development.

On the other hand, **Europe** has a mature biogas and biomethane industry with growing markets. In European countries with a developed industry, governments are seeking to encourage cost reductions and more competitive business models that rely less on public support and more on market revenues, for instance clean energy certificate trading or Guarantee of Origin schemes.

IEA. CC BY 4.0.

Traditionally, biogas has been promoted for power generation at combined heat and power plants. However, with access to competitive renewable electricity growing, governments are exploring ways to apply biomethane flexibility to industrial and transport uses, either directly or through gas grid injection. While the German government still provides support for biogas-fired electricity production, as biogas is considered critical to balance electricity networks in the south of the country, the United Kingdom incentivises both electricity generation and grid injection. France, which has a more decarbonised electricity generation mix, has long experience (since 2001) in supporting grid injection of biomethane even from small, rural farm-sized plants – through, among other means, planning and facilitating grid connections under the 2019 Right to Injection decree. TSOs/DSOs partly subsidise grid connections in Germany (75%) and France (60%).

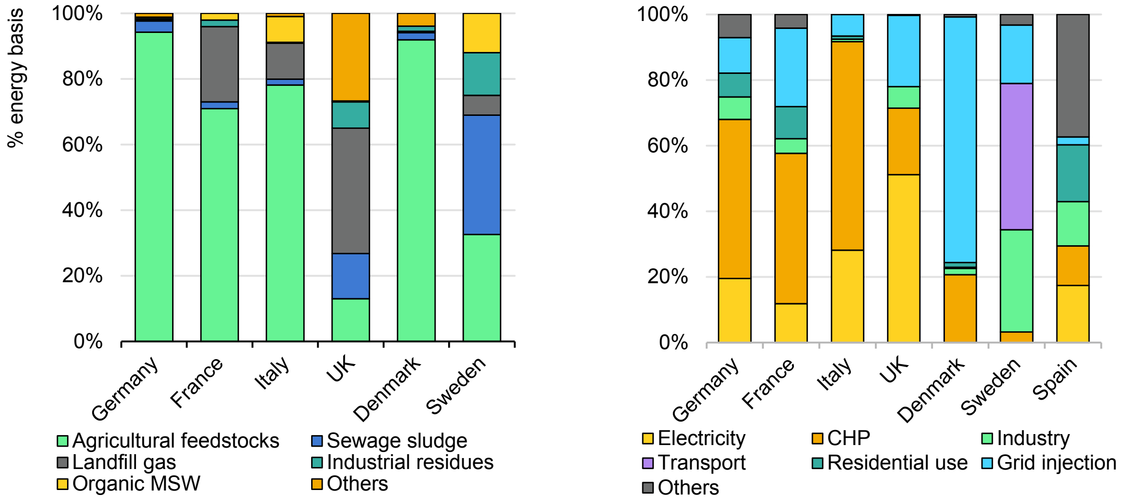
Meanwhile, biomethane use as a vehicle fuel still claims only a small share of biomethane production (20% in 2021), but growth is accelerating in many European states. Many countries already have large compressed natural gas (CNG) and liquified natural gas (LNG) vehicle fleets, and the number of CNG/LNG-specific filling stations in the beginning of 2023 was considerable in Italy (over 1 500), Germany (over 760), Sweden, France and Czechia (over 200), and is growing quickly. Currently, biomethane makes up around 20% of gas consumed by gas-fuelled vehicles.

In Europe, biomethane produced from organic residues and waste is considered an advanced biofuel to comply with specific EU RED II renewable fuel quotas, and demand for it is rising. Furthermore, advanced biofuels also count double in the general renewable transport quota. While energy crops have supported notable biogas production growth in Germany over the last 10 years, policies now favour more sustainable feedstocks such as waste and residues. As a result, corn and cereal grains are limited to only 40% of feedstock use in biogas production. Other countries such as France have forbidden the use of energy crops for biogas production, and a lot are now encouraging the use of animal manure, usually by offering tariff premiums (e.g. Germany and France).

At the same time, many countries are producing less biomethane from landfill gas (UK production dropped from 84% in 2010 to 38% in 2022), due partially to the 2018/850 EU Landfill Waste Directive and the Waste and Resources Strategy for England that ban organic material in municipal solid waste going to landfills by 2030. However, the organic fraction of municipal solid waste that contributes to landfill gas, when collected separately, is still a valid feedstock source for biogas plants. Additionally, EU Directive 2018/851 mandates the separate collection of biowaste starting in 2024. Moreover, the new proposed EU Urban Wastewater Treatment Directive will push for treatment plants to become energy-neutral, and a good way to achieve this is to produce biogas from sewage sludge.

IEA. CC BY 4.0.

Combined biogas and biomethane feedstock shares (left) and final end-use shares (right) in selected European countries, 2021



IEA. CC BY 4.0.

Notes: MSW = municipal solid waste. CHP = combined heat and power. "Agricultural feedstocks" includes crop and plant residues, animal manure, sequential crops and energy crops.

Sources: IEA analysis based on EBA and IEA data

In the **United States,** biomethane development has historically been driven by the transport sector and support schemes such as the Renewable Fuel Standard (RFS) and California's Low Carbon Fuels Standard (LCFS) applicable to fuels sold in California. The recent RFS Set Rule, released in June 2023, established specific annual volume obligations for RNG for three years (2023-2025) that have to be fulfilled by fuel retailers by either producing renewable fuels or buying tradable Renewable Identification Numbers (RINs) from producers. RIN credit values vary in the market, and there are specific volume obligations for each renewable fuel category, with biomethane being included in the D5 (advanced biofuel) or D3 (cellulosic biofuel) categories. The inclusion of a new pathway for biogas-based electricity used in electric vehicles is under discussion.

In addition to California, other states have developed their own support schemes, such as Washington's Clean Fuel Standard and Oregon's Clean Fuels Program, to offer additional sources of income for RNG sold in the state. The United States is currently the world's largest user of biomethane for transportation (almost 1.4 bcm in 2021), with a 48% share of biomethane in gaseous transport fuels (98% in California).

New policies such as the Inflation Reduction Act (IRA), signed in August 2022, provide extensive federal support for different applications, for instance through production tax credits for new biomass gas and landfill gas facilities producing renewable electricity; investment tax credits for biogas upgrading equipment and qualified biogas property; and a hydrogen tax credit that includes biogas as a feedstock for hydrogen production. Another programme that supports non-

IEA. CC BY 4.0.

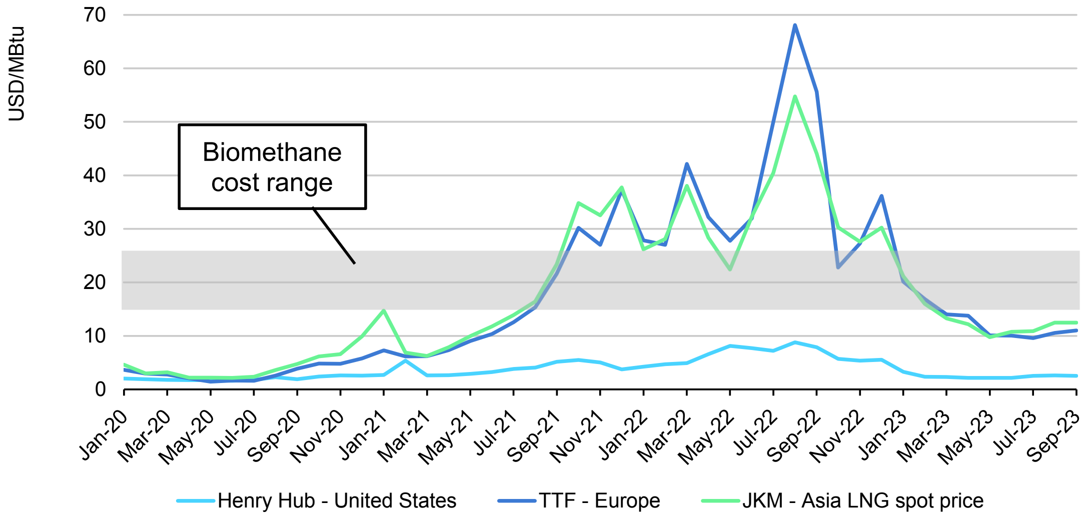
transport uses of RNG is California's RNG Procurement Program (February 2022), which aims to divert organic waste from landfills, with the final goal of reducing methane emissions into the atmosphere.

In the United States, the primary feedstock for biogas and biomethane production has been landfill gas (72% of biomethane production in 2021), the lowest-cost source for biogas. In the country with the lowest natural gas costs, other feedstocks have traditionally been expensive. Nevertheless, new facilities are now using mostly agricultural and animal wastes owing to strong incentives to use farm-based feedstocks, especially in California. In fact, California is now allocating ultra-low carbon intensity status to dairy industry projects because of their much lower livestock methane emissions, and to swine farms as well. The share of animal manure in RNG production in California evolved from 18% in Q1 2021 to 50% in Q2 2023.

Although biomethane production **costs** are usually higher than for natural gas, it is not subject to the price volatility that natural gas suffers from, and during the energy crisis it was valued at a lower price in Europe and Asia. Monetising climate benefits through a carbon tax on fossil fuels can help close the price gap between biomethane and natural gas.

The cost of producing biomethane varies depending on the feedstock, production scale and operating costs. For a mature industry sector such as Europe's, costs are estimated at EUR 55-90/MWh (USD 17-28/MBtu). Injection costs can add another EUR 3-4/MWh, and liquefaction an additional EUR 12/MWh. Meanwhile, applying a CO_2 cost of EUR 90/t to fossil fuels could increase the natural gas price by around EUR 18/MWh (USD 6/MBtu).

Biomethane production costs and natural gas prices, 2020-2023



IEA. CC BY 4.0.

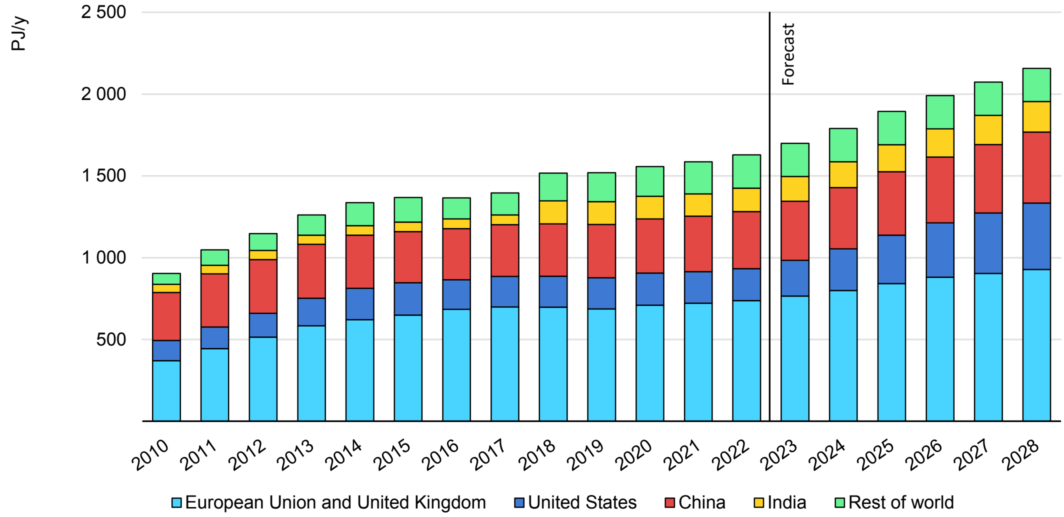
Sources: IEA analysis based on Cedigaz and IEA data.

IEA. CC BY 4.0.

Biogas and biomethane forecast

Compared with 2017-2022, global biogas production growth is expected to accelerate over 2023-2028 thanks to the introduction of impactful new policies in more than 13 countries in 2022-2023. The most growth will be in Europe and North America, owing partially to established infrastructure and experience, and driven by previous policies that make rapid deployment in a five-year term possible. China and India also have ambitious expansion plans, but their lack of infrastructure limits growth in the next five years. However, since both countries have considerable biogas production potential, rising energy demand and ambitious decarbonisation goals, they will be ready for accelerated growth beyond 2028.

Global historical and forecast production of biogases, 2010-2028



IEA. CC BY 4.0.

In **Europe**, electricity generation has been the main impetus for biogas expansion for the last two decades, but recent policies promote diversification of biogas uses, utilising biomethane. Thus, the majority of growth in biogases in Europe over the forecast period is expected to come from biomethane, from both new plants and upgraded existing biogas plants.

In some major markets such as Germany, transport is the end use that provides the most revenue for biomethane producers who benefit from clean-fuel certificates for renewable fuel quotas. It is also a strong growth driver in countries that already have gas vehicle fleets and filling stations. In addition, the European Union has initiated the inclusion of biogas and biomethane in its Guarantee of Origin system that industry can use to comply with the EU ETS or private companies can utilise to achieve their own emissions reduction targets.

The RED II regulates biogas Guarantees of Origin. So far, some countries are already keeping count with national registries and bilateral agreements that enable

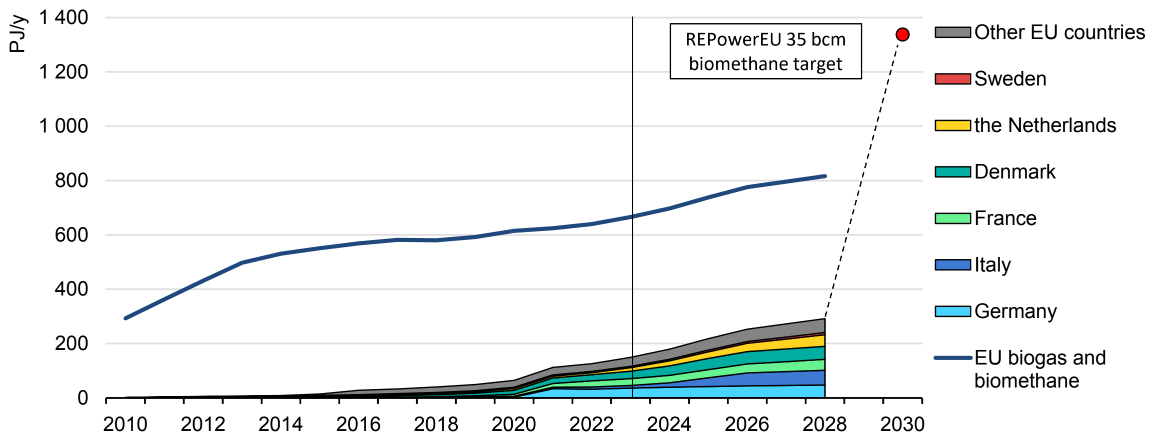
IEA. CC BY 4.0.

cross-border biomethane trading (Denmark, Germany, the Netherlands, Austria, Switzerland, the United Kingdom and France). Further deployment of this mechanism in other countries will help increase international trade, through either physical gas exchanges or certificate trading.

Some countries are switching from fixed feed-in tariffs to tendering systems for gas (France) or changing the conditions for electricity tenders (Germany). The latest auctions for electricity production from biomethane in Germany in 2023 did not received any bids. Meanwhile, France's new auctions for gas injection have been delayed since 2022. In Italy, however, the first auction in the new tender scheme for injected biomethane for transport and other uses in 2023 was 45% allocated just three months after its release, providing good prospects for 2023-2028. In several European countries, new policies reducing remuneration remain a forecast uncertainty as new conditions can reduce the economic attractiveness and weaken investor confidence for biogas projects.

In its 2022 REPowerEU plan, the European Union set a non-binding target of 35 bcm of biomethane by 2030, but growth will need to accelerate to achieve this target. Although some countries already have high shares of biomethane in their grids (Denmark achieved a remarkable 37.9% in November 2023), others are at earlier development stages (Belgium, Spain and Poland).

EU historical, forecast and targeted biomethane production, 2010-2030

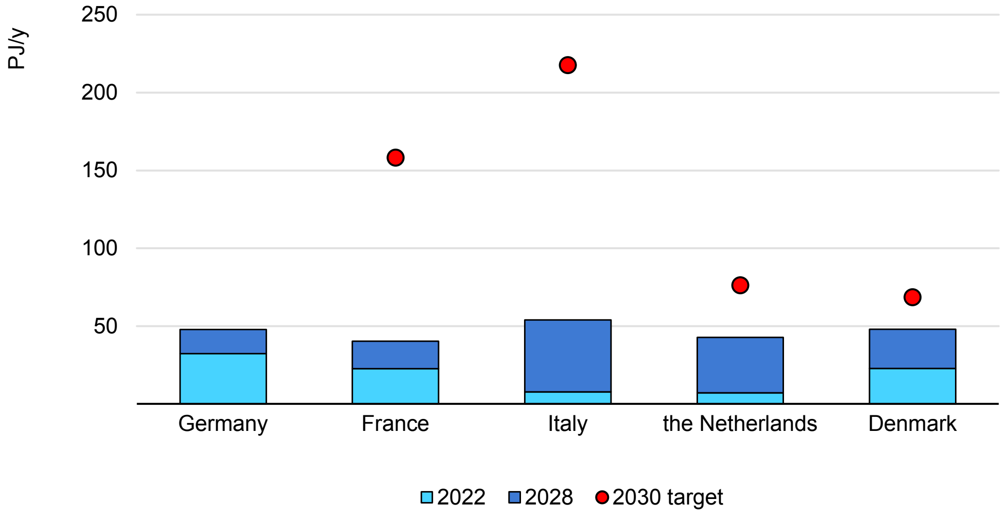


IEA. CC BY 4.0.

Note: Part of the biomethane production increase is expected to come from the upgrade of existing biogas facilities.

IEA. CC BY 4.0.

Current, forecast and targeted biomethane production for selected European countries, 2022-2030



IEA. CC BY 4.0.

Note: Germany does not have a specific biomethane target for 2030.

The **United States** has further accelerated its production growth for biomethane in the last years, prompted by new federal and state-level policy support. The new RFS Set Rule aims to double biomethane supplies in the next three years. Given the obligation volumes proposed, the pipeline of projects under development and California's targets for injected biomethane, biogas and RNG supplies combined are expected to expand 2.1-fold in the next five years. Generous financial support from various programmes that permit additionality provide a very favourable framework for the accelerated growth.

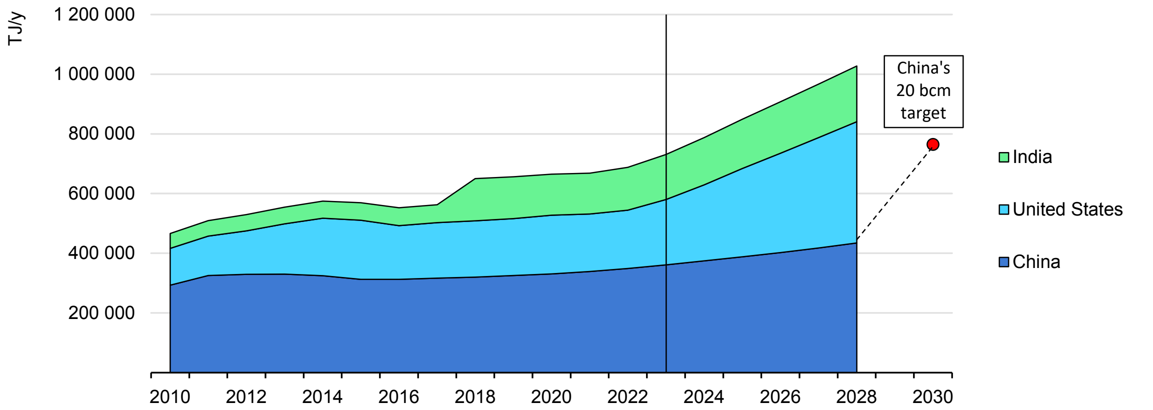
In **China**, the government actively developed new policies in 2022 with its 14th Five-Year Plan for Renewable Energy Development. Although the biogas targets of previous five-year plans for renewable energy were not achieved, revitalisation of the sector is expected for three reasons: national and international energy companies (PetroChina, China Three Gorges Corporation, China General Nuclear Power Group, French company Air Liquide and German company EnviTec Biogas AG) are beginning to invest in biogas; policy support has been strengthened; and grid access has been improved. Nevertheless, our forecast expansion of 20% over 2023-2028 is low compared with China's ambitious national target of 20 bcm by 2030.

India's government has also set very ambitious targets for several biogas end uses, including in transport, with extensive policy development to support them: the SATAT scheme for transport and industrial fuel; the 2022 Waste to Energy Programme to finance the recovery of urban, industrial and agricultural waste; and the 2022 National Biogas Programme for rural and semi-urban areas.

IEA. CC BY 4.0.

However, the deployment of industrial-scale production facilities is slow. For instance, in October 2023 the SATAT programme had just [48 plants commissioned](#) of the 5 000 new plants targeted for 2024. Ongoing challenges for India are the establishment of supply chains to mobilise agricultural residue, animal manure and organic municipal waste collection as well as completion of the necessary gas infrastructure improvements (through the One Nation, One Gas Grid programme), which create forecast uncertainty. Nonetheless, India's production of biogases is forecast to expand 30% over 2023-2028. The SATAT scheme's very ambitious targets for transport (an additional 15 Mt/year of biomethane use by 2023/2024) are still expected to be achieved, but with some delay.

China, US and India historical and forecast production of biogases, and China's 2030 target



IEA. CC BY 4.0.

Net Zero Emissions by 2050 Scenario tracking

According to the IEA Net Zero Scenario, production of biogases should quadruple by 2030. Although we expect growth to accelerate from 19% in 2017-2022 to 32% in 2023-2028, an even higher pace is required to meet the Net Zero objective for 2030. Biogas is a mature technology. It is a viable energy source for clean cooking, and can be employed as a dispatchable source of low-emissions electricity generation, which will be increasingly important as the deployment of variable renewables such as wind and solar expands.

As a drop-in substitute for natural gas, biomethane can be used employing the same pipeline and storage infrastructure, and it can provide all the energy services currently met by natural gas, including in hard-to-abate sectors such as heavy industry (e.g. chemical and fertiliser production). Plus, the cost of producing

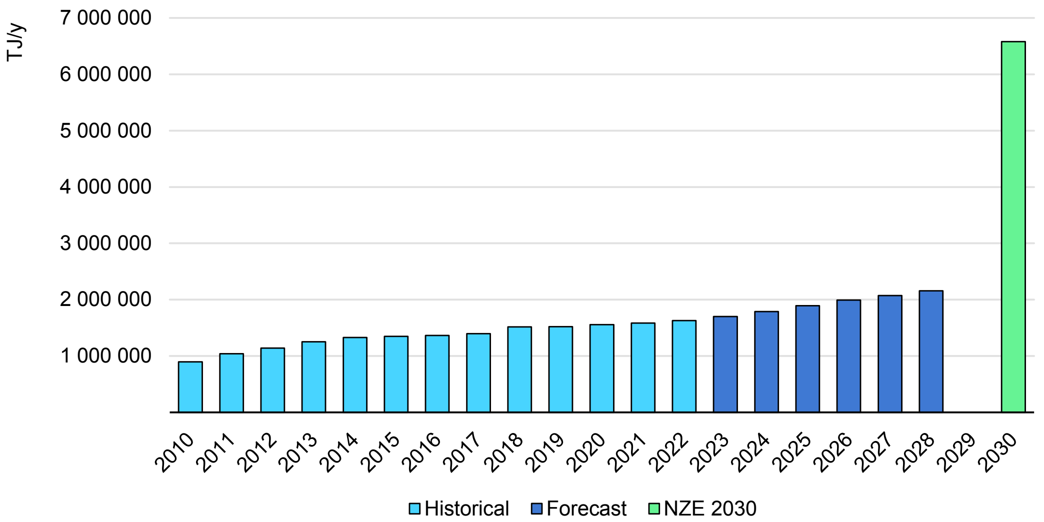
IEA. CC BY 4.0.

biomethane is currently competitive with other clean-energy solutions that reduce emissions in these sectors (e.g. hydrogen, hydrogen-based fuels and CCUS).

All countries thus need to make major efforts to surpass forecast biogas production and achieve the Net Zero trajectory. China and India would have to accelerate the development of feedstock supply chains in the agriculture, livestock and city waste sectors and offer more attractive incentives to make biogas production economically attractive. The development pace of critical gas grid infrastructure and associated end-use facilities will also dictate growth.

European countries will need to intensify their efforts to ensure that incentives for investors are still attractive in the new tendering systems, in view of incomplete allocations in some recent auctions. Other regions with strong biogas potential, such as Latin America and Southeast Asia, could make significant contributions to global growth if enough public support is obtained to launch development of the sector.

Global historical and forecast production of biogases and Net Zero Emissions Scenario target for 2030



IEA. CC BY 4.0.

Note: NZE = IEA Net Zero Emissions by 2050 Scenario.

IEA. CC BY 4.0.

International Energy Agency (IEA)

This work reflects the views of the IEA Secretariat but does not necessarily reflect those of the IEA's individual member countries or of any particular funder or collaborator. The work does not constitute professional advice on any specific issue or situation. The IEA makes no representation or warranty, express or implied, in respect of the work's contents (including its completeness or accuracy) and shall not be responsible for any use of, or reliance on, the work.

Subject to the IEA's Notice for CC-licenced Content, this work is licenced under a Creative Commons Attribution 4.0 International Licence.

This document and any map included herein are without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Unless otherwise indicated, all material presented in figures and tables is derived from IEA data and analysis.

IEA Publications
International Energy Agency
Website: www.iea.org
Contact information: www.iea.org/contact

Typeset in France by IEA - January 2024
Cover design: IEA
Photo credits: © Shutterstock

Revised version, Jan 2024
Information notice found at:
www.iea.org/corrections