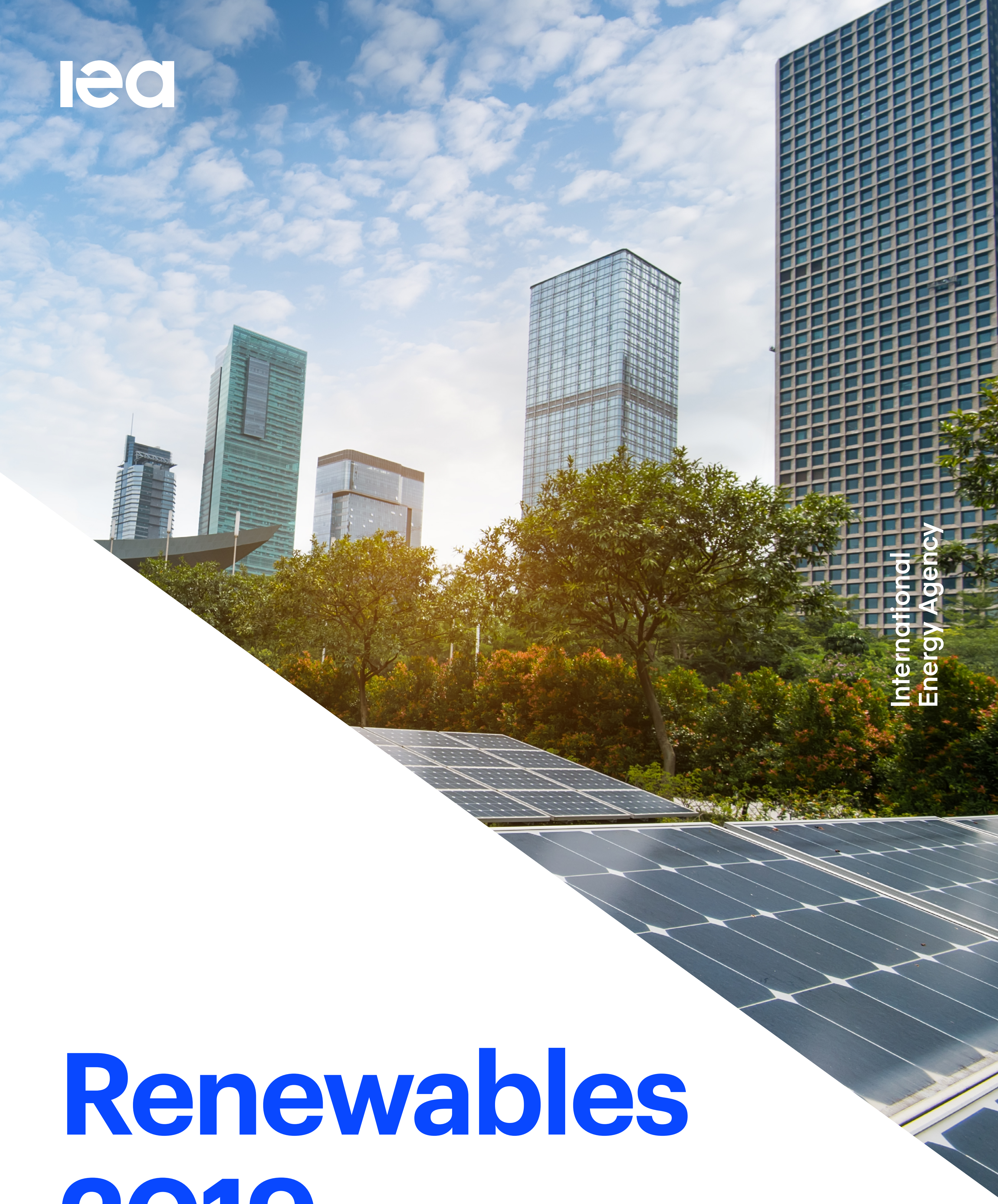

Renewables 2019

Analysis and forecast to 2024

Renewables 2019

Analysis and forecast to 2024

Explore data behind the Renewables 2019

The IEA is expanding the availability of data behind *Renewables 2019 Analysis and Forecast to 2024*. Please visit www.iea.org/renewables2019 to find all related press materials of the Report including executive summary, launch presentation and key figures.

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Foreword

This is a pivotal time for renewable energy. Thanks to falling costs, technologies such as solar photovoltaics (PV) and wind are at the heart of transformations taking place across the global energy system. Their increasing deployment is crucial for efforts to tackle greenhouse gas emissions, reduce air pollution, and expand energy access.

The International Energy Agency's (IEA) latest market report delivers an authoritative update on where renewable technologies stand today and where they are headed in the next five years. It provides the analytical foundation for IEA work that helps countries navigate their clean energy transitions in secure and cost-effective ways.

There are many encouraging findings in this report, especially for solar PV. After stalling last year, global capacity additions of renewable power are set to bounce back with double-digit growth in 2019. But while this year's rebound for renewables is positive, they still need to be growing far more strongly in order to achieve long-term sustainable energy goals. The IEA Sustainable Development Scenario – which outlines a path to meeting the Paris Agreement climate goals, curbing air pollution, and achieving universal energy access around the world – makes it clear that much greater efforts are required.

Another issue on which the IEA has been focusing is how power systems can handle higher shares of variable renewables. This is a critical topic, as electricity security must remain a cornerstone of our long-term energy development, regardless of the power source. That is why the IEA and the German Federal Ministry for Economic Affairs and Energy held the first Global Ministerial Conference on System Integration of Renewables earlier this month. At the event, ministers, CEOs, system operators and experts shared best practices and ideas for fully grasping the opportunities of wind and solar PV.

The focus of this year's report is distributed solar PV – the use of the technology by households, industrial plants and other businesses to generate their own electricity – which is set to become economically attractive in most countries by 2024. Such meteoric growth of solar power outside the realm of traditional power providers is set to transform the way we generate and consume electricity. It has significant implications for consumers, businesses, system operators, policy makers, and regulators. The expansion of distributed solar PV needs to be managed well in order to ensure stable revenues for grid maintenance, to contain system integration costs, and to allocate costs fairly among electricity consumers.

Renewable energy technologies – including wind, solar, hydropower, and bioenergy – are key pillars that will underpin global energy transitions. The IEA is committed to working with countries around the world to help them develop the right policies to ensure a secure and sustainable future for all.

Dr. Fatih Birol
Executive Director
International Energy Agency

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Questions or comments?

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Executive summary

Solar PV drives strong rebound in renewable capacity additions

Renewable power capacity additions are expected to increase in 2019 at their fastest pace in four years. After stalling in 2018 for the first time in almost two decades, additions are set to rise by 12%. This renewed growth is driven by solar photovoltaic (PV), owing to rapid expansion in the European Union, a stronger market in India and an installation boom in Viet Nam. Higher growth in onshore wind also supports this rebound, particularly in the United States, the European Union and the People's Republic of China ("China").

Renewable power capacity is set to expand by 50% between 2019 and 2024, led by solar PV. This increase of 1 200 GW is equivalent to the total installed power capacity of the United States today. Solar PV alone accounts for almost 60% of the expected growth, with onshore wind representing one-quarter. Offshore wind contributes 4% of the increase, with its capacity forecast to triple by 2024, stimulated by competitive auctions in the European Union and expanding markets in China and the United States. Bioenergy capacity grows as much as offshore wind, with the greatest expansions in China, India and the European Union. Hydropower growth slows, although it still accounts for one-tenth of the total increase in renewable capacity.

Falling costs and more effective policies drive a significant upward revision in the forecast for renewable capacity deployment compared with last year's report. Solar PV generation costs are estimated to decline a further 15% to 35% for both utility-scale and distributed applications by 2024. Recent competitive auction results indicate that the levelised cost of generation for utility-scale solar PV plants will become comparable with or lower than that of new fossil fuel plants sooner than expected in a growing number of countries. Competition and cost reductions also drive expansion in both on- and offshore wind capacity.

The European Union and the United States are responsible for half of the upward revision in the forecast. A more optimistic outlook for the European Union results from higher planned renewables auction volumes and faster distributed solar PV growth in member states to meet renewable energy targets. In the United States, wind and solar PV developers are rushing to complete projects before federal tax incentives end, while corporate power purchase agreements (PPAs) and state-level policies contribute to growth. Our forecast for renewable capacity expansion in China to 2024 is higher than last year because of improved system integration, lower curtailment rates, and the enhanced competitiveness of both solar PV and onshore wind. In India, renewable capacity doubles by 2024, mostly in solar PV. But ongoing challenges concerning the operational and financial health of distribution companies, land acquisition, grid reinforcement, and access to financing hamper faster progress. Sub-Saharan Africa is the only region for which our forecast has been revised downwards, as growth is held back by continued delays in implementing announced policies, high investment risks, and weak grid infrastructure.

Renewable electricity growth still needs to accelerate significantly to meet long-term sustainable energy goals. This growth is possible if governments address the three main challenges to faster deployment: policy and regulatory uncertainty; high investment risks in many developing economies; and system integration of wind and solar PV in some countries. Tackling these challenges underpins our *Accelerated Case* forecast in which total renewable capacity increases more than 60% to 4 000 GW by 2024, by which time it is twice the size of today's global coal capacity. Annual deployment rises to 280 GW – 50% higher than the current rate and in line with long-term sustainable energy goals.

Distributed solar PV takes centre stage

Distributed solar PV systems in homes, commercial buildings and industry are set to take off, bringing significant changes in power systems. A rapid rise in the ability of consumers to generate their own electricity presents new opportunities and challenges for electricity providers and policy makers around the world. Distributed PV capacity more than doubles to 530 GW by 2024, an increase equal to that of onshore wind or almost half of total solar PV.

China is forecast to account for almost half of global distributed PV growth, overtaking the European Union to become the world leader in installed capacity as early as 2021. Nevertheless, distributed PV expansion still picks up significantly in the European Union during 2019-24 as it becomes more economically attractive and the policy environment improves. While Japan remains a strong market, India and Korea emerge as drivers of capacity growth in Asia. Expansion of distributed solar PV in North America is twice as rapid between 2019 and 2024 as it was during 2013-18, mainly driven by the United States.

Contrary to conventional wisdom, distributed PV growth is dominated by commercial and industrial applications rather than residential. The economic case for commercial and industrial applications – which represent almost three-quarters of new distributed PV installations through 2024 – is generally better than for residential systems. This is because economies of scale lead to lower investment costs per kilowatt (kW) and because supply and demand are usually better aligned, enabling more self-consumption and larger savings on electricity bills.

Some 100 million solar rooftop systems for homes could be operating worldwide by 2024. Residential systems are set to account for one-quarter of total distributed solar PV capacity by then, with deployment expanding rapidly in many countries owing to favourable policy designs and the economic attractiveness of distributed PV. The top five markets for residential PV installations per capita in 2024 are Australia, Belgium, California (United States), the Netherlands, and Austria.

Rapid cost reductions could lead to a distributed PV boom. In most countries, commercial and residential systems already have electricity generation costs that are lower than the variable portion of retail electricity prices. Residential and commercial solar PV costs are forecast to decline a further 15% to 35% by 2024, making the technology more economically attractive and spurring adoption worldwide. Our *Accelerated Case* shows that a combination of increasingly favourable economics, enhanced polices and more effective regulation could push the global installed capacity of distributed PV above 600 GW by 2024 – almost double the total installed power capacity in Japan today. However, based on available rooftop area, even this is only 6% of distributed PV's technical potential. The increasing economic attractiveness of distributed PV systems could therefore lead to a massive expansion in the coming decades, attracting hundreds of millions (or even billions) of private investors.

Major policy and tariff reforms are required to make distributed PV growth sustainable. Currently, some distributed solar PV policies – such as buy-all, sell-all and annual net metering with retail-price remuneration – can have undesired effects. Unmanaged growth can disrupt electricity markets by raising system costs, challenging the grid integration of renewables and reducing the revenues of distribution network operators. Tariff reforms and appropriate policies will be needed to attract investment in distributed PV while also securing enough revenues to pay for fixed network assets and ensuring that the cost burden is allocated fairly among all consumers.

Renewable electricity uptake benefits the heat sector

Heat generated from renewable energy is set to expand by one-fifth between 2019 and 2024. Buildings account for over half of global renewable heat growth, followed by industry. China, the European Union, India and the United States are responsible for two-thirds of the global increase in renewable heat consumption over the forecast period. However, renewables' share of global heat consumption increases only marginally, from 10% today to 12% in 2024. Overall, renewable heating potential remains vastly underexploited and deployment is not in line with global climate targets, calling for greater ambition and stronger policy support.

Renewable electricity used for heat is forecast to rise by more than 40%, a similar increase to that of bioenergy, accounting for one-fifth of global renewable heat consumption by 2024. This growth results mainly from a rising share of renewables in electricity generation and, to a lesser extent, greater electrification of end uses. Modern bioenergy remains by far the largest source of renewable heat by 2024. More than two-thirds of bioenergy growth is forecast to occur in the industry sector, mostly in India, China and the European Union.

China to lead biofuel production growth for the first time

Total biofuel output is forecast to increase 25% by 2024. In 2018, production grew at its fastest pace for five years, propelled by a surge in Brazil's ethanol output. Overall, Asia accounts for half of the growth, as its ambitious biofuel mandates aimed at reinforcing energy security boost demand for agricultural commodities and improve air quality. In addition to biofuels, renewable electricity provides around 10% of renewable energy in transport by 2024, most of which is in China.

China is set to have the largest biofuel production growth of any country. By 2024, ethanol production is expected to triple, driven by the rollout of 10% ethanol blending in a growing number of provinces and increasing investments in production capacity. Brazil registers the second-largest growth, boosted by the introduction of the Renovabio programme in 2020. The United States and Brazil still provide two-thirds of total biofuel production in 2024.

Hydrotreated vegetable oil (HVO) production is set to accelerate, raising competition with biodiesel. HVO output more than doubles, accounting for one-fifth of biofuel production growth to 2024, comparable with the contribution of biodiesel and making it by far the largest source of advanced biofuels. HVO offers higher flexibility for blenders, the possibility to use of waste and residue feedstocks, and higher-value co-products such as renewable propane and chemicals. Over the next five years, policy-driven demand in the European Union and the

United States is forecast to stimulate USD 5 billion of investment in new HVO plants, a number of which will also produce aviation biofuels.

Sustainable biofuel production and consumption need to accelerate considerably to be in line with long-term climate targets. In our main forecast, renewable energy still meets only 5% of transport energy demand by 2024. Our *Accelerated Case* indicates a possible 20% additional growth by 2024, which requires enhanced policy support to demonstrate sustainability, spur the consumption of higher biofuel blends in key markets, and open up new markets in aviation and marine transport. Financial de-risking measures are also needed to encourage investment in less mature advanced biofuel technologies that can use a wider range of waste and residue feedstocks.

1. Renewable electricity forecast

Highlights

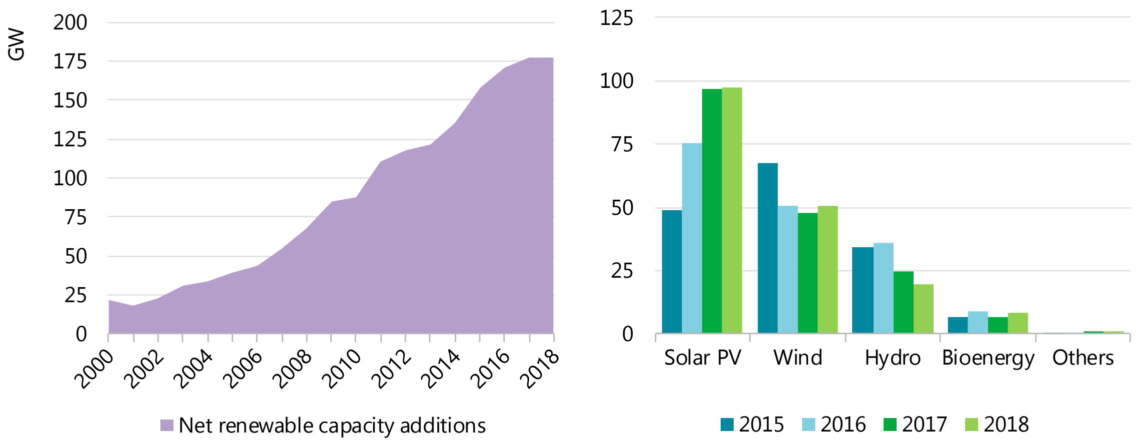
- **Renewable power generation capacity expanded 178 gigawatts (GW) in 2018**, similar to 2017, but net additions did not increase year-on-year (y-o-y) for the first time since 2001, mainly due to slower solar photovoltaic (PV) growth in the People's Republic of China ("China") resulting from a policy transition. However, renewable capacity additions are expected to rebound significantly (+12%) in 2019.
- **In the main case forecast, renewable capacity increases 1.2 terawatts (TW) (+50%) over 2019-24**, accounting for two-thirds of global power capacity additions, including fossil fuel-based and nuclear. The forecast has been revised up by over 14% from *Renewables 2018* to account for continued cost reductions and policy improvements for solar PV as well as on- and offshore wind in key markets. Hydropower and bioenergy expansion remain stable, while prospects for concentrated solar power (CSP) and geothermal have been revised downwards.
- **Solar PV accounts for almost 60% (700 GW) of all renewable capacity expansion**, followed by wind (351 GW), 12% of which is offshore. In 2020, cumulative wind and PV capacity together surpass that of hydropower. Growth prospects for new hydropower capacity remain strong (121 GW) but are concentrated in emerging economies and developing countries.
- **Renewables are forecast to provide 30% of global electricity generation by 2024**, second after coal, with hydropower remaining the largest source of renewable power. Although their output doubles, wind accounts for only 7% of the global power mix and solar PV for 5%.
- **Renewables expansion remains largest in China**, with 489 GW becoming operational over 2019-24 (84% from wind and solar PV). The transition from feed-in tariffs (FITs) to competitive auctions is expected to make wind and PV more competitive with coal. For the European Union, the forecast has been revised up by 46% to reflect more ambitious energy plans and auction schedules. Wind and solar together account for 95% of the 180-GW capacity growth in 2019-24.
- **The United States demonstrates the third-largest growth globally**, with its forecast revised up by 14% thanks to improved state policies, higher corporate procurement and continuous cost reductions. India's renewable capacity almost doubles owing to competitive auctions for solar PV and wind, although the operational and financial health of its distribution companies (DISCOMs) continues to hinder the pace of deployment, while land acquisition, grid constraints and access to financing also remain challenging.
- **The forecast for Latin America is slightly less optimistic due to auction delays and grid connection and financing challenges.** Slow progress in large-scale project development has also caused the forecast for sub-Saharan Africa to be revised downwards, while a more rapid pace of deployment in the Middle East and North Africa (MENA) points to more optimistic growth prospects.
- **In the accelerated case, renewable capacity growth could be 26% (1.5 TW) higher than in the main case.** This case requires that governments address three main challenges: 1) policy and regulatory uncertainty; 2) high investment risks in developing countries; and 3) system integration of wind and solar in some countries. Distributed PV is the single largest source of additional expansion potential, followed by utility-scale PV, onshore wind and hydropower.

Recent deployment trends

Total renewable electricity capacity increased by 178 GW in 2018, similar to net capacity added in 2017 (Figure 1.1). For the first time since the beginning of the 21st century, however, net renewable capacity additions did not increase y-o-y. But despite stalling, renewable capacity additions still accounted for 75% of all net power capacity growth.

Prior to 2018, renewable capacity growth had been increasing steadily despite decelerating hydropower and wind additions, which peaked in 2013 (hydropower) and 2015 (wind) after record-level expansion in China for both technologies in those years. Meanwhile, solar PV additions expanded exponentially in China, making up the difference and resulting in a sustained upwards trend in total renewable capacity additions globally. In 2018, however, China's PV market experienced its first substantial annual decline as a result of a change in policy direction to control expansion, reduce subsidy costs, address curtailment and ultimately make PV expansion more sustainable. This contraction was offset by capacity additions in other growing PV markets such as Australia's and Europe's, keeping global growth stable relative to 2017.

Figure 1.1 Annual net capacity additions by technology



In mid-2018, China suspended FIT approvals for solar PV and introduced deployment caps for distributed generation projects, causing solar PV additions to fall from 53 GW in 2017 to 44 GW in 2018. Still, China accounted for almost 45% of the total global renewable electricity capacity increase in 2018. With the country's wind curtailment rate declining 5 percentage points y-o-y to 7%, wind additions gained speed in 2018. Hydropower expansion decelerated, however, maintaining a trend that began in 2013.

The second-largest renewable capacity growth occurred in the European Union, with 85% of its renewable expansion from solar and wind and the majority of the rest from bioenergy. The region's growth was slightly slower than in 2017, however, as onshore wind additions declined somewhat with the transition to competitive auctions in Germany and reduced policy support in the United Kingdom. Meanwhile, annual PV additions in the European Union increased by over 40% y-o-y to over 8 GW in 2018, mainly owing to Germany, where PV growth almost doubled. In addition, EU bioenergy additions doubled from 2018 (3 GW) thanks to large-scale plant conversions in the United Kingdom and a combination of biogas and solid biomass combustion plants in the Netherlands.

In the United States, renewable capacity additions increased slightly in 2018, mainly as a result of higher onshore wind expansion. However, policy uncertainty surrounding PV module import tariffs introduced last year caused developers to suspend plans, resulting in project delays and diminished growth.

India's annual renewable capacity growth slowed, with a 40% decline in onshore wind caused by the policy transition from administratively set incentives to competitive auction schemes; these declines were not offset by the slight expansion of solar PV. In Japan, the revised FIT scheme reduced annual PV additions to 6.7 GW in 2018, i.e. 40% below the 2015 peak.

Outside of large markets, renewable capacity expansion accelerated in many emerging and developing economies in the Middle East, North Africa and parts of the Asia-Pacific region, led by wind and solar PV because of rapidly falling costs and stronger policy support.

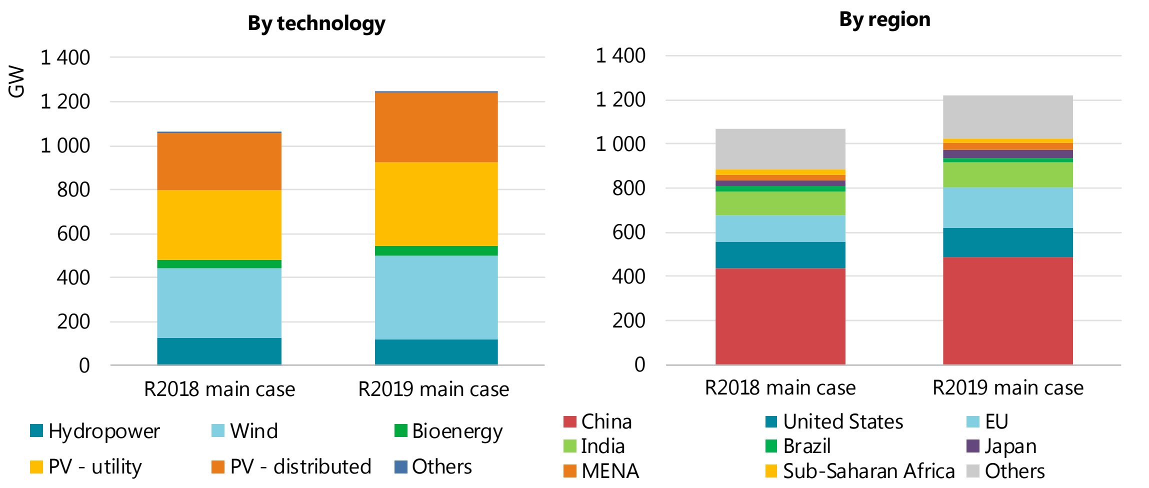
Forecast summary

Global capacity forecast

In the main case forecast, renewable electrical capacity increases 50% (1 220 GW) by 2024, from 2 502 GW in 2018. Solar PV, including utility-scale and distributed applications, accounts for almost 60% of all renewable capacity expansion over the forecast period, followed by wind, hydropower and bioenergy (Figure 1.2). China remains the largest market, accounting for 40% of all renewable capacity growth over the forecast period, followed by European Union, the United States and India.

Overall, the forecast has been revised upwards by over 14% from *Renewables 2018* owing to a more positive outlook for solar PV and on- and offshore wind. These revisions largely reflect the sustained cost reductions foreseen for these technologies and improvements in the general policy and regulatory environment, especially since the announcement of new competitive auctions. The main case forecast for hydropower and bioenergy remains consistent with last year, while the outlook for CSP and geothermal has been revised down slightly in light of slow project development in multiple markets.

Figure 1.2 Renewable electricity capacity forecast summary



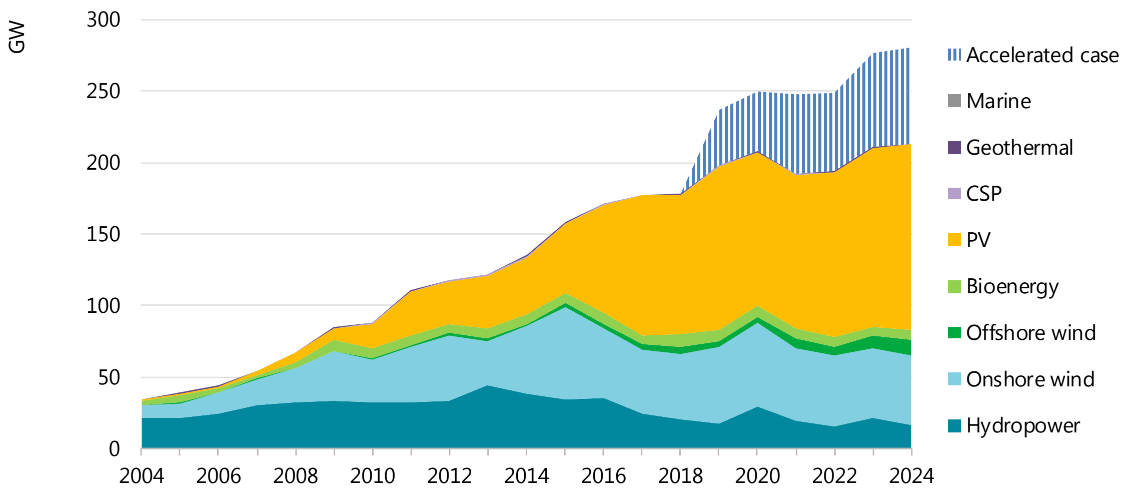
Notes: R2018 = *Renewables 2018* forecast for 2018-23 (IEA, 2018). R2019 = *Renewables 2019* forecast for 2019-24.

Almost 40% of the upward revision results from a more optimistic outlook for the European Union, owing to an increase in planned auction capacities over the forecast period to meet the 2020 and 2030 targets within the EU Renewable Energy Directive. China's forecast growth is also higher than last year's as a result of improved system integration for variable renewables and because solar PV and onshore wind becoming increasingly more competitive. The US renewable capacity forecast is more optimistic as well, reflecting improved PV and wind competitiveness. India's outlook remains largely the same as last year's, as challenges concerning DISCOM financial health and grid integration persist.

After stalling in 2018, global annual capacity additions are forecast to resume growth in 2019 (Figure 1.3). Accelerating growth in North America, Europe and the Asia-Pacific region is expected to offset the stable growth foreseen for China. Global additions hit a record 207 GW by 2020 before declining in 2021, a trend that results from events in two countries: in the United States, onshore wind additions peak in 2020 then decline as the production tax credit (PTC) is phased out, and in China several large-scale conventional and pumped hydro projects are expected to be commissioned in 2020.

Solar PV capacity increases 2.5-fold over the forecast period, reaching almost 1.2 TW in 2024 in the main case. Faster cost reductions and supportive policy frameworks worldwide underpin the more optimistic forecast for both utility-scale and distributed applications. Overall, utility-scale plants are forecast to represent 55% of total solar PV expansion. In 2019, global solar PV additions are expected to rebound, mainly in the European Union and Viet Nam, after remaining flat in 2018. China accounts for over 40% of global PV growth, followed by the European Union and the United States, which demonstrate similar capacity expansion in the next six years. With solar PV becoming more economically attractive, growth accelerates in Latin America, Eurasia, the Middle East and Africa.

Figure 1.3 Annual renewable capacity additions by technology, main and accelerated cases



Onshore wind capacity is forecast to expand 57%, to 850 GW by 2024 in the main case forecast. Annual onshore wind additions reach almost 60 GW in 2020, resulting from a development rush in the United States before the PTC is phased out, and in China from the policy transition from FITs to competitive auctions. Global annual installations are expected to be lower (around 50 GW) from 2021 to 2024, as growth will be slower in China and the United States. Expansion accelerates in the European Union, however, as competitive auctions continue to keep costs relatively low. In Latin America, the MENA region, Eurasia and sub-Saharan Africa, the auction schedule ensures strong capacity growth over the forecast period. Grid integration, financing and social acceptance are the key challenges to faster onshore wind expansion globally.

Hydropower remains the world's primary source of renewable power in 2024. Capacity increases 9% (121 GW) over the forecast period, led by China, India and Brazil. One-quarter of global growth is expected to come from just three megaprojects: two in China (the 16-GW Wudongde and 10-GW Baihetan projects) and one in Ethiopia (the 6.2-GW Grand Renaissance project). Apart from these three large projects, however, new capacity additions continue to decline over the forecast period. This is largely due to a slowdown in the two largest markets, China and Brazil, where growth is challenged by rising investment costs due to remaining economical sites being limited and to extra expenditures to address social and environmental impacts. Nevertheless, new capacity is expected in sub-Saharan Africa and in the Association of Southeast Asian Nations (ASEAN) region as untapped potential is exploited to meet rising power demand. **Pumped storage hydropower (PSH)** also expands, driven by the need for greater system flexibility to integrate increasing shares of renewables in the electricity generation portfolios of China, Europe, North America and Australia.

Offshore wind capacity is forecast to increase almost threefold (+43 GW) to 65 GW in 2024, producing almost 10% of total world wind generation. Although the European Union accounts for half of global offshore wind capacity expansion over 2019-24, on a country basis China leads deployment, with 12.5 GW in development through numerous projects having continued policy support under the FIT scheme. Outside of China, record-low contract prices prompt expansion in the United Kingdom, Denmark, the Netherlands and Germany, with several auction rounds already finalised with zero-subsidy contracts. The first large US capacity additions are also expected to come online during the forecast period, followed by those of Chinese Taipei.

Bioenergy capacity increases 32%, to 171 GW by 2024. While this accounts for just 3% of total renewable capacity growth, bioenergy is nevertheless responsible for 8% of renewable generation at the end of the forecast period. Global additions remain stable at 6 GW to 8 GW, with China providing almost 50% of new capacity, mainly in the form of solid biomass co-generation[1] and energy-from-waste (EfW) projects. Japan provides the second largest increase in bioenergy capacity additions owing to projects approved under the generous FIT scheme. India and Brazil are the next-largest growth markets because of bagasse-fuelled co-generation, linked to the sugar and ethanol industry. In the European Union, 3 GW of additions in 2018 (the highest since 2011) is not reached again. Europe's capacity expands by just under 7 GW over the entire forecast period, led by the United Kingdom, the Netherlands and Turkey, owing to its emerging biogas market.

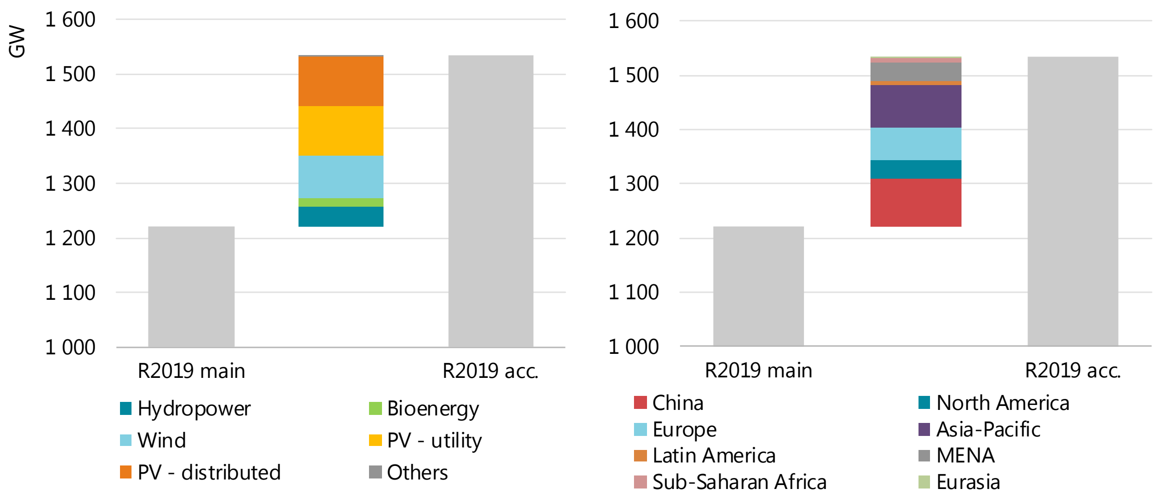
Geothermal capacity is anticipated to grow 28%, reaching 18 GW by 2024, with Asia responsible for one-third of global expansion, mainly through projects currently under construction in Indonesia and the Philippines, followed by Kenya, whose cumulative geothermal capacity is set to overtake Iceland's in 2019. Pre-development-stage risks continue to be an important challenge, impeding the rapid development of untapped geothermal potential. Global **CSP** capacity is forecast to increase 60% to 9 GW by 2024 in the main case, led by China

[1] *Co-generation* refers to the combined production of heat and power.

and deployment in the MENA region, but **marine** technologies expand only 60 MW with pilot and small-scale projects.

In the **accelerated case**, renewable capacity expansion is 26% (1 540 GW) higher than in the main case, with annual additions accelerating to 280 GW by 2024 – 57% higher than 2018 and in line with the International Energy Agency (IEA) Sustainable Development Scenario (Figure 1.4). The accelerated case requires that governments address the three main challenges preventing faster deployment: 1) policy and regulatory uncertainty; 2) high investment risks in developing countries; and 3) system integration of wind and solar electricity in some countries. Distributed PV along has the largest potential for increased deployment in the accelerated case, especially for commercial applications (the drivers, challenges and economics of the distributed PV forecast are discussed in Chapter 2). In an increasing number of countries where electricity is not subsidised, solar PV generation costs are declining to become comparable with variable retail electricity prices, making net-metering and self-consumption opportunities more attractive. However, retail tariff design and policies for remunerating excess generation remain key forecast uncertainties in many countries.

Figure 1.4 Accelerated case expansion above main case, by technology and region



Notes: R2019 main = *Renewables 2019* main case forecast for 2019-24. R2019 acc. = *Renewables 2019* accelerated case forecast for 2019-24.

With higher auction frequency and quicker project development across all regions, utility-scale solar PV and wind have similar expansion potential in the accelerated case. Timely grid infrastructure expansion, access to affordable financing, and overcoming social acceptance and land acquisition challenges will be required to realise the accelerated case forecast, however, especially in developing and emerging economies. Overall, China accounts for the majority of accelerated case growth, followed by Europe, the Asia-Pacific region and the MENA region.

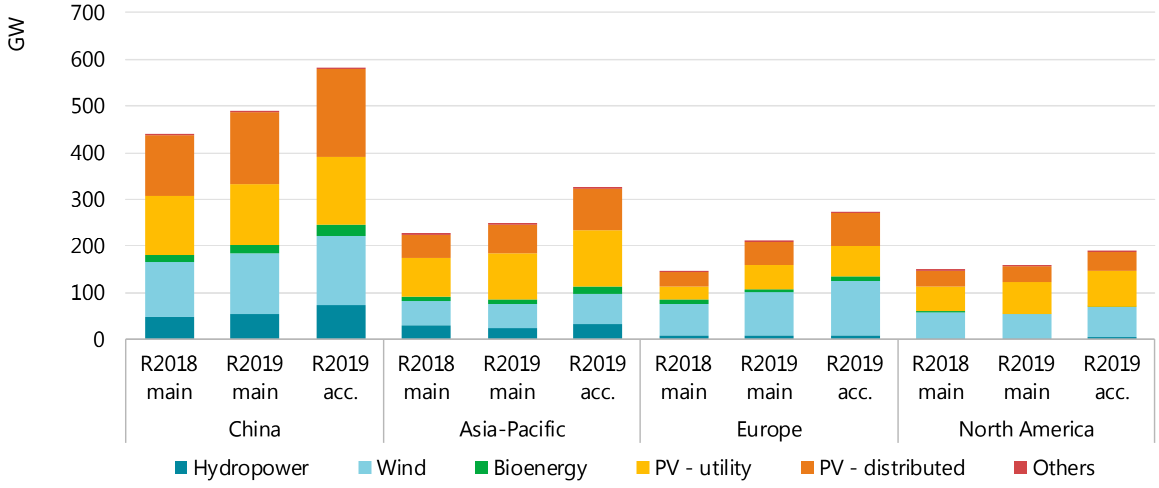
Regional capacity forecast

China's renewable capacity is expected to increase almost 70% over the forecast period (Figure 1.5). The policy transition from FITs to competitive auctions with an annual subsidy cap is expected to provide more cost-effective and sustainable solar PV and onshore wind deployment, and to make wind and solar energy more competitive with provincial benchmark electricity prices. In addition, wind and solar PV projects without additional subsidies are emerging in several provinces, accepting provincial benchmark electricity prices for long-term remuneration. Although grid integration remains a challenge, lower curtailment levels suggest it is becoming less of a constraint on the expansion of variable renewable technologies. Despite these developments, the bankability of projects with low or no subsidies that have curtailment risks remains a key challenge. China's growth could be 19% higher in the accelerated case, depending on how cost-competitive wind and solar PV projects become under the proposed budget subsidy cap, how quickly provincial auctions are implemented, and whether lower curtailment enables faster commissioning of variable renewables over the forecast period.

The second-largest growth occurs in the **Asia-Pacific** region (excluding China), led by solar PV and followed by wind and hydropower. Capacity expands 64% during 2019-24, with India accounting for almost half of the increase as it implements competitive auctions for utility-scale PV and wind. However, the operational and financial health of DISCOMs continues to impede deployment and the impacts of land acquisition difficulties, grid constraints and lack of access to financing remain forecast uncertainties. In Japan, growth is driven by the generous FIT for all renewable technologies and auctions for utility-scale and commercial solar PV. The renewable capacity forecast for the ASEAN region has been revised down slightly due to continued policy and regulatory challenges in Indonesia, the Philippines and Thailand, whereas Korea's has been revised upwards, mainly for solar PV, to reflect the government's new 2040 targets based on renewable portfolio standards (RPSs) with generous incentives for renewable power producers under the renewable energy certificate (REC) programme. Under the accelerated case, the region's renewable capacity growth could be one-third higher, with India contributing 45% of the additional capacity if the financial performance of DISCOMs improves and grid integration and financing challenges are minimised. Additional expansion in the accelerated case forecast for the Asia-Pacific region also assumes continued momentum for PV in light of the FIT rule changes in Japan; the overcoming of policy uncertainties and lack of access to financing in ASEAN countries; and permitting and grid integration improvements in Korea.

In **North America,** solar PV and wind account for 95% of all renewable capacity growth in the next six years. The United States leads expansion, with a more optimistic solar PV forecast than last year, mostly for utility-scale projects, as the impact of the tax reform and import tariffs on project bankability is expected to be more limited than previously assumed. In addition, improved and extended state-level RPSs and corporate public-private agreements (PPAs) remain strong stimulants. In Mexico, the suspension of green certificate auctions raises forecast uncertainty and results in less optimistic growth prospects for renewables. For Canada, the forecast has been revised down due to a less promising outlook for onshore wind as provincial policy changes in Alberta, Quebec and Ontario introduce uncertainty. Accelerated deployment in North America will therefore depend on wind and solar projects becoming more cost-competitive in the United States as federal tax incentives are phased out, as well as faster grid expansion in the mid-western states and higher renewable electricity procurement from corporate customers. In Mexico and Canada, current uncertainties concerning auctions and support schemes need to be clarified rapidly in order to achieve higher growth.

Figure 1.5 China, North America, Europe and Asia-Pacific: Renewable capacity forecast summary

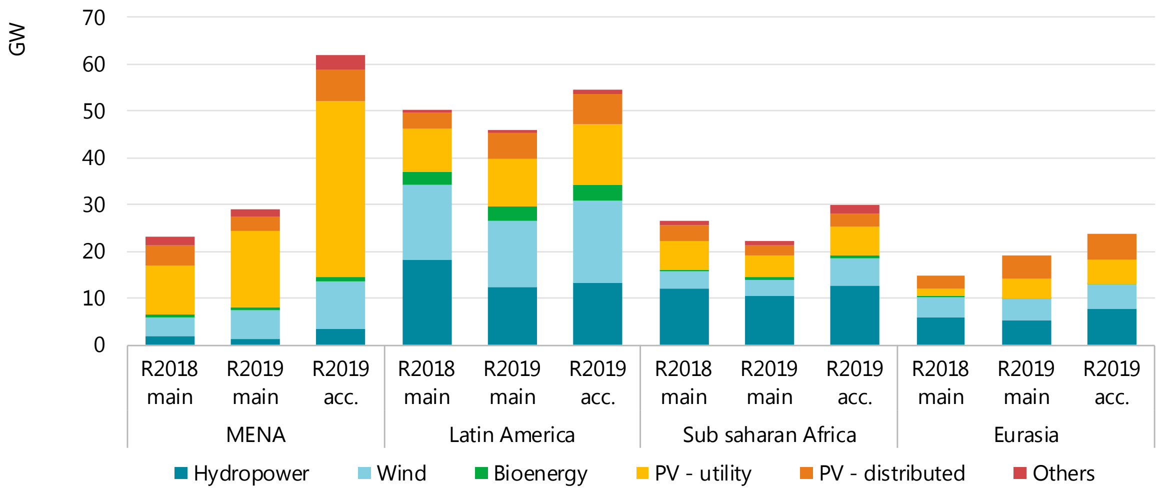


Notes: Acc. = accelerated case. R2018 = *Renewables 2018* forecast for 2018-23 (IEA, 2018). R2019 = *Renewables 2019* forecast for 2019-24.

Europe's renewable capacity is expected to increase by one-third (209 GW) over 2019-24, led by Germany, Spain, France, the Netherlands and Turkey. Solar PV expands the most, with distributed PV accounting for almost half of the PV added, followed by onshore wind, offshore wind, hydropower and bioenergy. The forecast has been revised up by one-third from *Renewables 2018* because additional auctions were announced in several countries (i.e. Germany, France, Spain and Poland) to close the gap to meet 2020 targets under the EU Renewable Energy Directive and accelerate progress towards the 2030 EU climate and energy goals. Higher distributed PV growth as a result of the economic attractiveness of self-consumption in Spain and Germany and net-metering in Turkey and the Netherlands, also supports the upward revision. Competitive auctions will drive most of the region's utility-scale expansion, and PPAs with corporate buyers and utilities also support the forecast, especially in markets with limited long-term support options (Sweden and Norway) or high electricity prices (Spain and the United Kingdom). However, permitting challenges, grid constraints, local opposition and limited visibility over policy support timelines beyond 2020 in some countries pose a risk to higher growth. Europe's deployment could be 30% higher with faster approval of grid connections, greater network expansion, more certainty over support measures such as auction schedules beyond 2020, and additional corporate PPA growth.

In **Latin America**, nearly two-thirds of renewable expansion is forecast to be in solar PV and onshore wind technologies, followed by hydropower (Figure 1.6). Brazil leads growth with half of total additions, which result from announced auctions and a number of slowly emerging merchant projects. However, a lack of large-scale hydropower project development beyond the commissioning of the Belo Monte project results in lower capacity growth in the region than in last year's forecast. The stable capacity expansion forecast for Argentina is based on anticipated auctions and corporate PPAs for utility-scale projects, whereas Chile's large-scale renewable project growth is expected to slow down towards the end of the forecast period because no auctions were held in 2018 and 2019. Grid congestion and the macroeconomic situation of the region overall remain key barriers to faster renewable deployment. Accelerated-case deployment in Latin America will therefore depend on the procurement of larger capacity volumes through regularly held auctions, access to low-cost financing, quicker adoption of corporate PPAs in key markets, rapid implementation of net-metering schemes, and adequate grid infrastructure to connect larger renewable capacities.

Figure 1.6 MENA, Latin America, sub-Saharan Africa and Eurasia: Renewable capacity forecast summary



Notes: Acc. = accelerated case. R2018 = *Renewables 2018* forecast for 2018-23 (IEA, 2018). R2019 = *Renewables 2019* forecast for 2019-24.

In **Eurasia**, the deployment of non-hydropower renewables gains momentum over the forecast period, with solar PV and onshore wind accounting for 70% of additions. Ukraine alone is responsible for 45% of the region's renewable expansion, prompted by strong policy support aimed at improving energy security. In early 2019, Ukraine adopted an auction system in addition to the FIT, and the two schemes will operate in parallel until phaseout of the FIT in 2030. The Russian Federation remains the second-largest market in the region owing to its use of competitive auctions and the completion of large hydropower projects currently under development. Other Eurasian countries are also implementing auctions to procure renewables, mainly wind and solar PV: in 2018, Albania, Armenia and Kazakhstan completed their first auction rounds, with PV prices averaging USD 58 per megawatt hour (/MWh) and onshore wind clearing at USD 53/MWh. The region's potential for greater capacity expansion under the accelerated case depends on renewable technologies being deployed at a quicker pace under the new auction schemes and on the adoption of net-metering policies across the region.

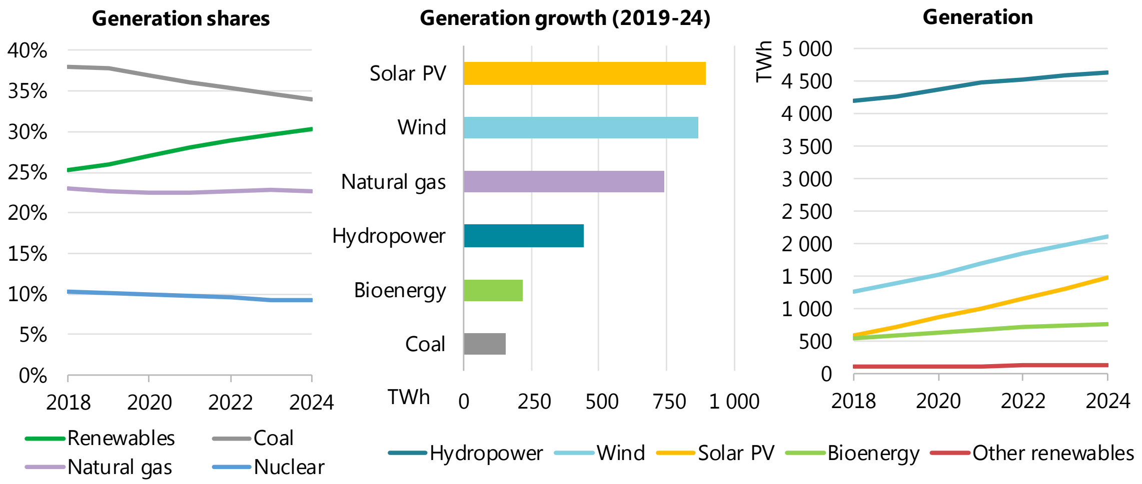
The **sub-Saharan Africa** region is forecast to add 22 GW of renewable capacity during 2019-24, a 4-GW downward revision from *Renewables 2018* because various large-scale projects, mainly solar PV, are developing more slowly than anticipated. Hydropower is expected to make up half of the region's additions as countries make significant progress in commissioning several large-scale projects, including Ethiopia's 6-GW Grand Renaissance Dam. Although concessional financing remains a key driver for the deployment of solar PV and onshore wind projects, which account for 45% of regional growth, access to affordable financing is still a primary barrier to faster expansion. Under the accelerated case, growth could be 36% higher if governments resolve the problems of PPA renegotiation risks, grid connection delays, administrative barriers and long-term renewable procurement uncertainty.

Renewable capacity in the **Middle East and North Africa (MENA)** region doubles during 2019-24, led by solar PV with smaller contributions from onshore wind and CSP. An increasing share of renewable expansion in the region is spurred by private sector investments (mostly from competitive auctions but also from bilateral contracts between corporate clients and utilities) and, to a lesser extent, by FITs. This year's forecast has been revised upwards 25% to reflect a more optimistic outlook for solar PV, resulting from new auctions planned in the United Arab Emirates, Saudi Arabia, Morocco, Oman and Kuwait. This trend was triggered largely by the increasing cost-effectiveness of solar PV owing to a combination of good resource potential, affordable financing and competitive bidding, which continues to produce some of the lowest tariffs in the world (USD 23-28/MWh last year). Distributed PV growth results mostly from net-metering schemes. Improved regulatory frameworks in Morocco and Saudi Arabia and gradually rising retail electricity prices in Jordan, Egypt and the United Arab Emirates are the main drivers of small-scale PV deployment. Challenges to faster growth are a lack of long-term auction schedules, delayed procurement processes, grid integration issues, and complex administrative procedures in some markets. Should these issues be addressed in the short term, growth in the accelerated case is demonstrated to be twice as high as the main case.

Generation forecast

Renewable electricity generation is the world's fastest-growing source of electricity, with its share increasing from 25% in 2018 to 30% by 2024 – compared with a decline in coal's share and a stable share for gas (Figure 1.7). The average growth rate of renewable generation (5.3%) is more than twice that of global power demand (2.1%), resulting partly from accelerated solar PV and wind growth (driven by rapid cost reductions) and partly from a slowdown in electricity demand (owing to greater energy efficiency and a structural shift in some economies to less energy-intensive industries). Renewables therefore make up a larger share of new electricity supplies as generation shifts away from coal, though coal is still expected to be the largest source of electricity in 2024.

Figure 1.7 Global generation shares by fuel, and growth by renewable technology, 2019-24

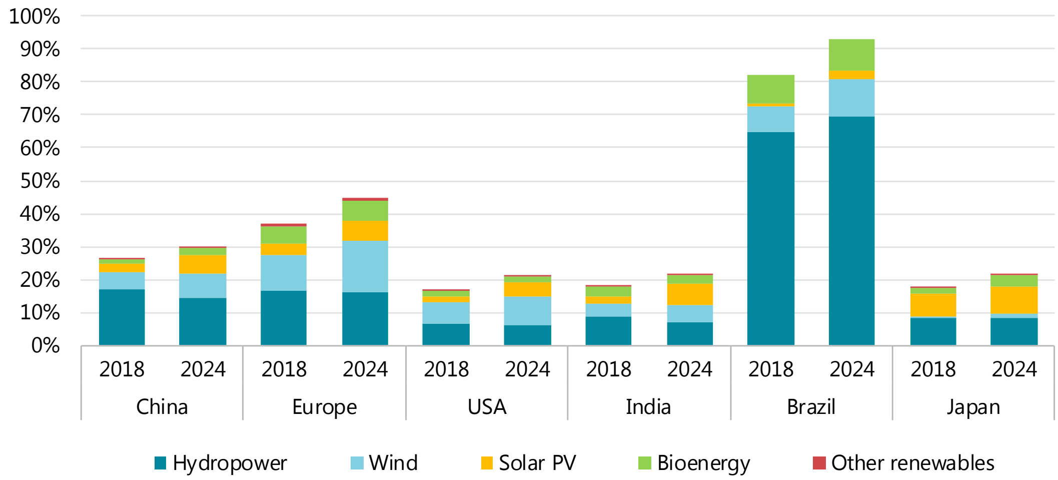


Notes: Other renewables = solar thermal, geothermal and marine. TWh = terawatt hour.

Source: For fossil fuel generation. World Energy Outlook 2019 (WEO) (IEA, forthcoming).

In absolute terms, renewable electricity generation increases 37% during 2019-24, led by solar PV, wind, hydropower and bioenergy, with contributions from other renewable technologies as well (Figure 1.8). This increase (2 450 TWh) covers two-thirds of global electricity generation growth, and is more than that from coal, gas, and nuclear combined. For the first time, solar PV registers the largest absolute growth of all electricity generation technologies over the forecast period. While most additional PV generation is from utility systems, distributed PV also makes a sizeable contribution. A large part of this comes from China, where distributed solar PV is the second-largest source of new renewable generation after wind. With this rapid expansion, global PV electricity generation surpassed that of bioenergy for the first time in 2018, becoming the third-largest source of renewable electricity. Hydropower remains the largest, followed by wind.

Figure 1.8 Generation shares and growth by renewable technology and region, 2019-24



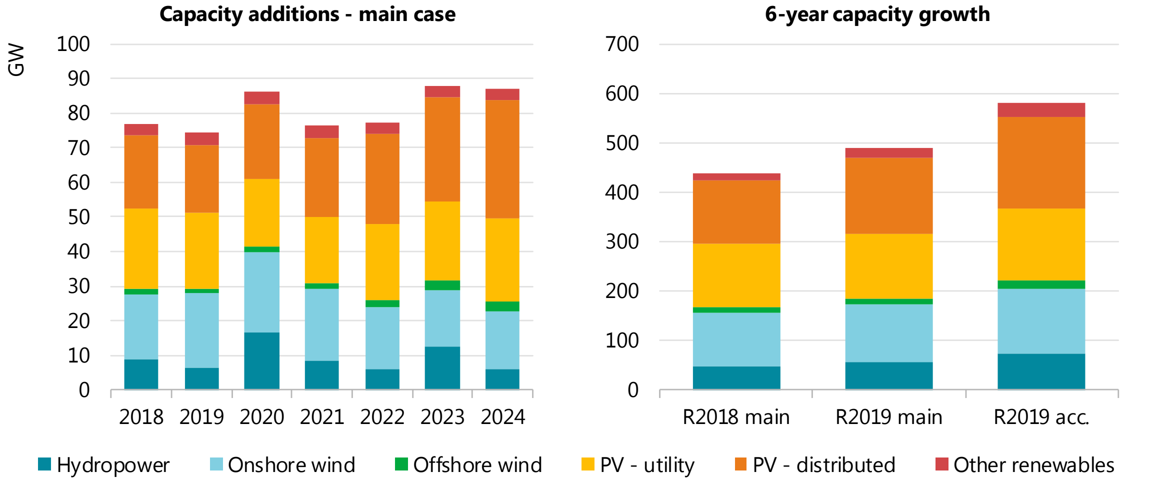
Note: *Others* refers to CSP, geothermal and marine

By 2024, renewable electricity generation totals more than 9 000 TWh, with 75% of it concentrated in just six markets: China first, then Europe, the United States, Brazil, India and Japan. Of these markets, renewables are most important in the electricity mix of Brazil, where their share in generation reaches 93% by 2024 owing to a considerable hydropower contribution. Bioenergy's impact is also notable, fuelling almost 10% of the country's generation. Europe's renewables share increases by 8 percentage points over the forecast period, reaching over 40% by 2024. Wind expansion accounts for the majority of this increase, followed by solar PV. In both China and India, additional renewable generation comes mostly from PV and wind, which outpace hydropower. Increased renewable generation is led by wind in the United States, while solar PV leads in Japan. Both countries pass the 20% renewable generation benchmark by 2024.

China

In the main case, China's renewable capacity is forecast to expand 67 (489 GW) over 2019-24, spurred by the government's commitment to reduce local air pollution and decarbonise the power sector. The forecast has been revised upwards based on: 1) a more optimistic forecast for solar PV because growth in 2018 was higher than expected; 2) the improved competitiveness of wind and solar; and 3) more onshore wind deployment as a result of reduced curtailment in the Northern China. China's policy transition from FITs to competitive auctions remains a key forecast uncertainty and, along with hydropower commissioning dates, is the main reason for annual capacity growth volatility (Figure 1.9). In the accelerated case, China's renewable electricity expansion is 19% higher than in the main case, with wind and solar PV accounting for the largest additional increases. The accelerated case forecast is based on faster implementation of centralised auctions, quicker cost reductions and improved grid integration (Figure 1.9).

Figure 1.9 China: Renewable electricity forecast summary



Notes: Acc. = accelerated case. R2018 = *Renewables 2018* forecast for 2018-23 (IEA, 2018). R2019 = *Renewables 2019* forecast for 2019-24.

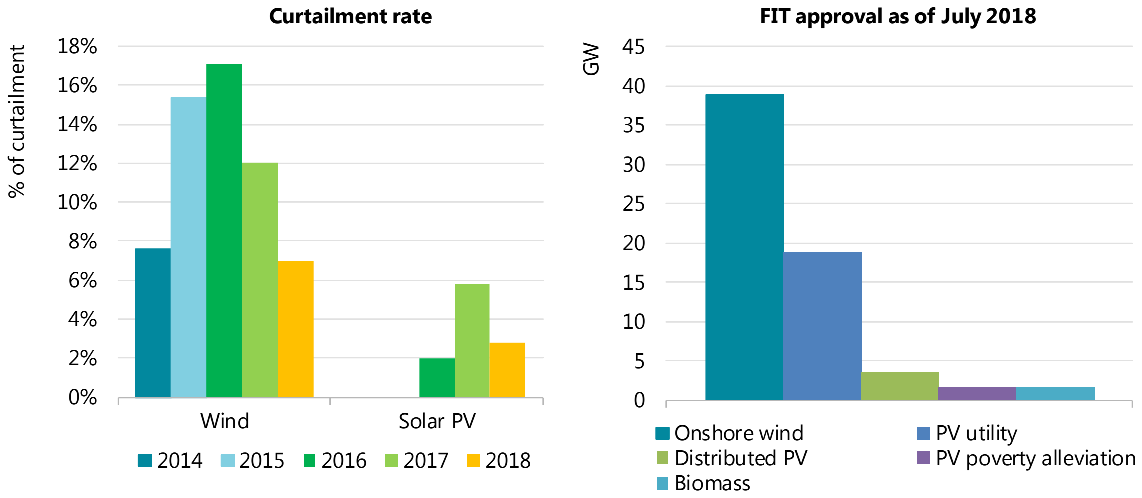
Wind and solar PV account for almost 85% of expansion in China's main and accelerated forecasts. As the goals of China's new wind and solar PV policy are mainly to reduce curtailment and cut spending on renewable energy subsidies, in the second quarter of 2018 the government announced a transition from FITs to competitive auctions to remunerate wind and solar PV. In mid-2018, the National Energy Administration (NEA) therefore issued a last batch of FITs to ensure a smoother transition to auctions in 2019-20 (Figure 1.10). Onshore wind received the majority of FIT capacity allocations because solar PV auctions[2] have already been in place since early 2018 and the relatively short construction time for installations minimises the risk of deployment lulls.

In 2018, wind curtailment was reduced by 5 percentage points and solar PV by 3 (Figure 1.10). The construction of additional transmission lines and a new warning system to prevent construction of wind and PV projects in areas of high curtailment and strong power demand growth, in addition to other measures, have enabled this achievement. New reforms to

[2] The Top Runner auction scheme, which was introduced in 2017 to select projects with the latest, most efficient PV technology.

improve system integration of renewables are also expected to facilitate growth: the introduction of more efficient cost-based dispatch of generation; increased power trading among provinces; and system flexibility incentives. Although some of these reforms have already been successfully implemented in pilot projects, the pace of widespread implementation remains a key uncertainty in forecasting wind and solar PV deployment.

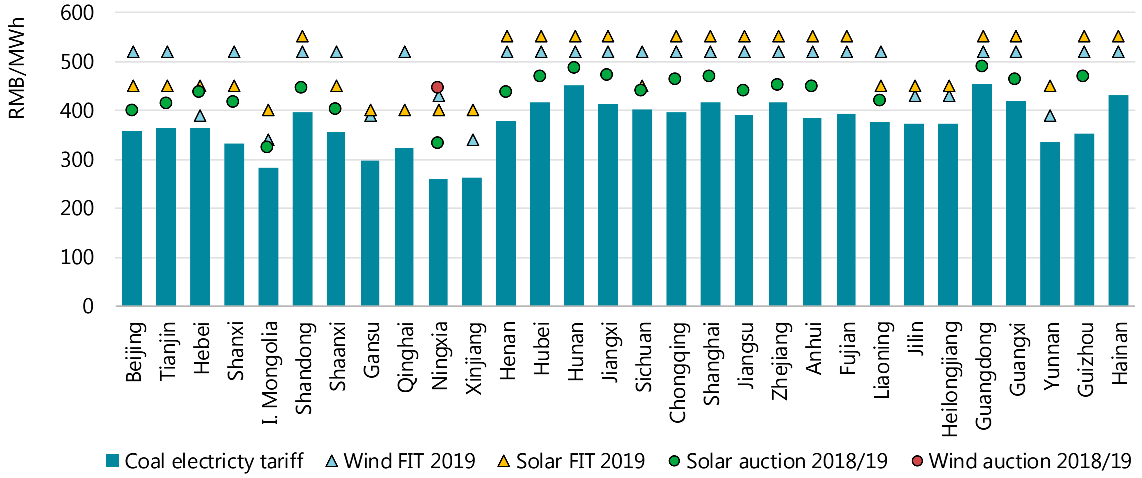
Figure 1.10 China: Wind and solar PV curtailment and FIT approvals



Sources: NEA (2019), Grid-connected renewable energy stations introduced to operation in 2018; NEA (2018), Renewable energy generation of 1.7 trillion kWh increased by 150 billion kWh year-on-year; NEA (2017a), 2016 wind power grid connection and operation; NEA (2017b), Reply to Recommendation No. 6938 of the Fifth Session of the 12th National People's Congress ; NEA (2016), Development of wind power industry in 2015; NEA (2015), Wind power industry monitoring in 2014.

The Chinese government aims to expedite progress in achieving grid parity for wind and solar PV with provincial benchmark coal prices (CNY 260-453/MWh or USD 37-65/MWh). Accordingly, the onshore wind FIT is set to phaseout at the end of 2020. Current FITs are above provincial benchmark electricity prices – 5% higher for wind in Hebei, to 56% higher for solar PV in Guizhou (Figure 1.11) – and even after recent reductions, wind and solar FITs still exceed actual generation costs (depending on the province) . In late 2018, Qinghai awarded solar PV projects on a par with provincial coal prices, while prices for the first 2-GW wind auction in Ningxia were only 9.4% below wind FITs of 2018, at CNY 0.49 per kilowatt hour (/kWh). Although auction rules are still being designed in many provinces, the National Development and Reform Commission (NDRC) approved over 20 GW of subsidy-free wind and solar PV projects in May 2019 and urged grid companies to sign 20-year PPAs with developers. Along with auctions, provincial RPSs with green certificates are expected to provide additional revenue to developers, but the implementation details were not yet clear at the time of writing.

Figure 1.11 China: Benchmark coal electricity price, FITs and auction results for selected provinces, 2019



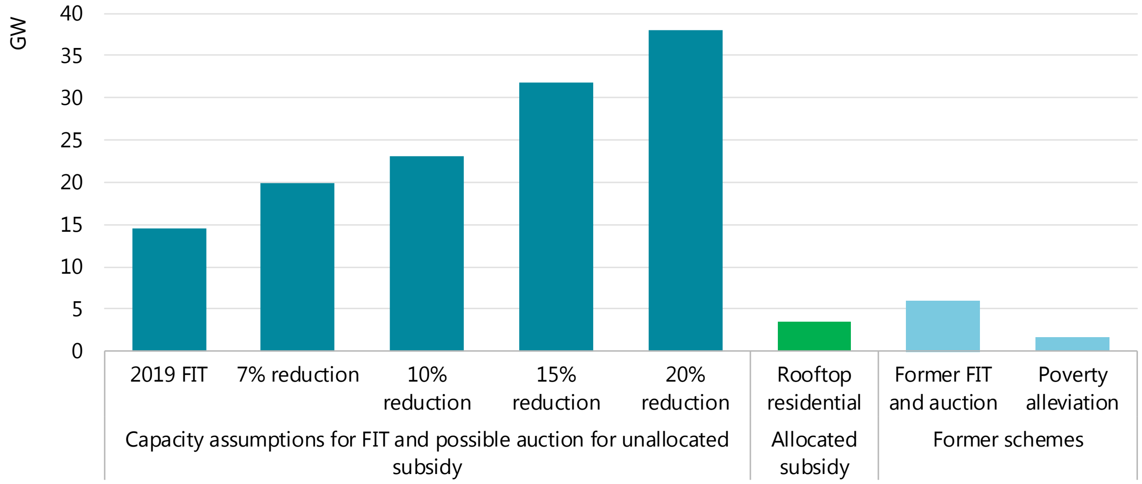
Based on additional FIT approvals, the new auction scheme and the emergence of grid-parity projects, **onshore wind** capacity is forecast to increase 65% (117 GW) over 2019-24. FITs drive onshore wind expansion in the short term, while competitive auctions and unsubsidised projects spur development beyond 2021. The forecast expects a development rush before the FIT ends in 2020, then a slowdown during the transition to auctions and unsubsidised projects. Overall, the pace of deployment will depend on curtailment levels in the Northwest and Northeast regions where most deployment is expected. In the accelerated case, onshore wind expansion could be 10% higher assuming system integration improvements and faster implementation of auctions and grid-parity projects. China's **offshore wind** growth is forecast to expand 12 GW in the main case and 16 GW in the accelerated, propelled mainly by the attractive FIT. Reaching the full accelerated case potential will require that permitting and grid integration challenges be overcome.

China's **solar PV** capacity increase – from 175 GW in 2018 to 459 GW in 2024 – is split almost evenly between utility-scale and distributed systems. The forecast has been revised up as the result of several developments, the first being faster-than-expected commercial PV deployment in 2018 in spite of recent policy changes. In response to the FIT phaseout and deployment caps introduced in 2018, *Renewables 2018* expected annual commercial growth to contract, but annual additions actually increased by 8% in 2018, highlighting the segment's economic attractiveness and prompting a more optimistic outlook in this year's forecast. Also supporting an upward revision are the emerging grid-parity projects. From 2019 onwards, annual growth for both utility-scale and distributed PV will be constrained by the annual budget cap introduced by the Ministry of Finance (the 2019 cap is CNY 3 billion [USD 440 million]). In addition, provinces are allowed to build grid-parity projects only if they do not have a "red flag" under the current curtailment warning mechanism.

Under the new budget cap, residential rooftop projects receive a fixed allocation of CNY 0.75 billion and they do not need to compete for subsidies, which will enable around 3.5 GW of capacity additions annually (Figure 1.12). Utility-scale, commercial and industrial projects will compete in provincial auctions for the remaining CNY-2.25 billion subsidy budget. Considering current FIT levels, this subsidy will enable only 15 GW of new projects per year. However, if developers offer bids 20% lower on average than the respective provincial FITs, almost 40 GW of capacity can be deployed through auctions.

In July 2019, the NEA approved subsidies for 20 GW of utility-scale and commercial/industrial PV projects under the new auction scheme. This implies that developers' bids were an average 8-10% below current FIT levels (Figure 1.11). In addition to this allocation, the main case forecast takes into account former incentive schemes (FITs and poverty alleviation programmes) and grid-parity projects for the delivery of another 21 GW, raising the annual total to around 41 GW in 2019. While stable annual additions of 41-42 GW are expected in 2020-21, further cost reductions result in a 58-GW increase in 2024.

Figure 1.12 China: Solar PV capacity assumptions based on announced subsidy cap



Several policy uncertainties hamper accelerated growth for solar PV. For utility-scale projects, provincial auction rules have yet to be clarified. Details of these rules are key not only to foster competition and reduce prices, but to ensure top-quality construction. As with wind, grid integration challenges for large-scale PV projects persist, despite lower curtailment levels. For distributed PV projects (especially commercial and industrial), the economics of self-consumption have been improving for commercial/industrial applications, but termination of the FIT introduces revenue uncertainty for small developers who may not have the resources to enter into auctions. If the government and provinces tackle these challenges, solar PV capacity growth is demonstrated to be 15 higher in the accelerated case.

Hydropower capacity is expected to increase 16%, with pumped-storage projects accounting for one-third of growth to enlarge system flexibility. Conventional plants account for the remaining two-thirds, mostly from two large-scale projects (Wudongde and Baihetan) totalling 26 GW that have been under development for several years. Both projects are to be commissioned in stages between 2020 and 2023, resulting in annual addition peaks. After the final units have been commissioned, annual hydropower growth is expected to contract sharply in 2024 due to the rising costs of new project development (many of the economically attractive sites have already been developed, and additional costs associated with social and environmental impacts also challenge bankability). Expansion potential in the accelerated case is based on the commissioning of some planned conventional and PSH projects, propelled by faster permitting and construction.

Bioenergy capacity increases almost 20 GW over 2019-24, in the process meeting the 23-GW target for 2020 in China's 13th Five-Year Plan (FYP). Supported by FITs, EfW projects provide almost half of new bioenergy capacity in the forecast. Robust deployment is anticipated as urbanisation and economic growth result in the pressing need to manage increasing volumes of municipal solid waste. Most remaining capacity growth is accounted for by biomass co-generation supported by a FIT in areas where access to biomass resources and heat demand overlap, e.g. in municipalities or industry. Biogas for electricity generation makes a relatively smaller contribution to the forecast.

Table 1.1 China: Drivers, challenges and accelerated case assumptions

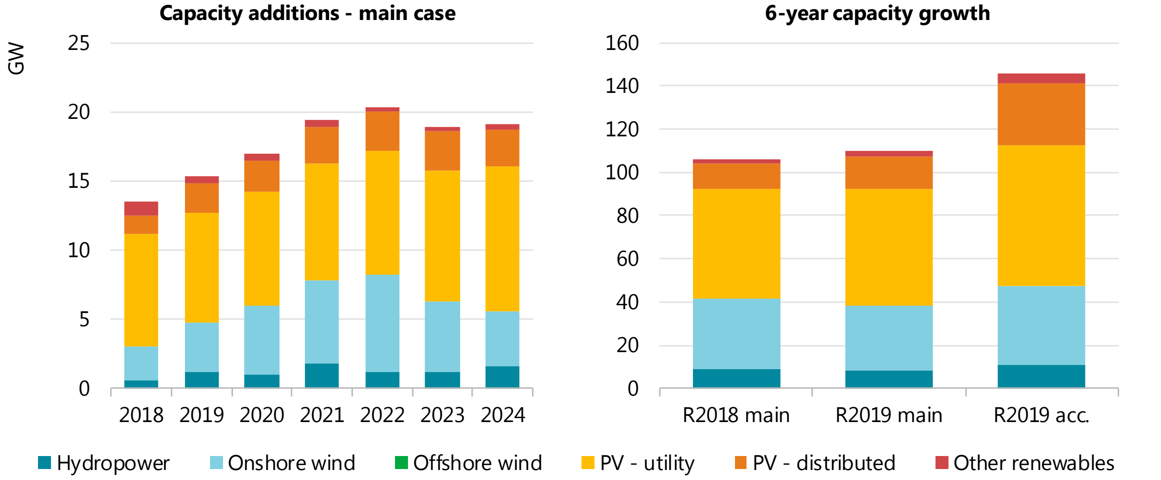
Country	Drivers	Challenges
China	Increasingly competitive wind and PV resulting from sustained cost reductions; unsubsidised projects; competitive auctions.	Uncertainty and slow implementation of RPS and power market reforms; continuous curtailment of wind, PV and hydropower output.
Accelerated case assumptions	Greater wind and PV competitiveness, enabling more auction capacity under the announced subsidy budget cap. Faster expansion of grid infrastructure and operational improvements, further reducing curtailment. Faster commissioning of large hydropower plants, and stronger fuel supply chains for bioenergy.	

Asia-Pacific

India

India's renewable power capacity is expected to almost double (+112 GW) over 2019-24 as electricity demand increases, renewables become more competitive and auctions become more widespread – all supported by the government target of 175 GW by 2022 and plans for 275 GW by 2027 in the 2018 National Electricity Plan (Figure 1.13). Utility-scale PV leads expansion, followed by onshore wind, distributed PV, hydropower and bioenergy. The forecast has been revised upwards slightly to reflect extension of the solar park scheme until 2022 and new initiatives for distributed and off-grid PV. Annual additions lose speed after 2022 due to policy uncertainty for onshore wind beyond the 2022 targets. The pace of growth in India depends on the operational and financial performance of its DISCOMs, progress under the green-energy corridors, and schemes to improve access to affordable financing. If successful, these factors could boost renewable capacity growth an additional one-third (+37 GW) in the accelerated case, mostly in utility-scale and distributed solar PV as well as onshore wind.

Figure 1.13 India: Renewable electricity forecast summary



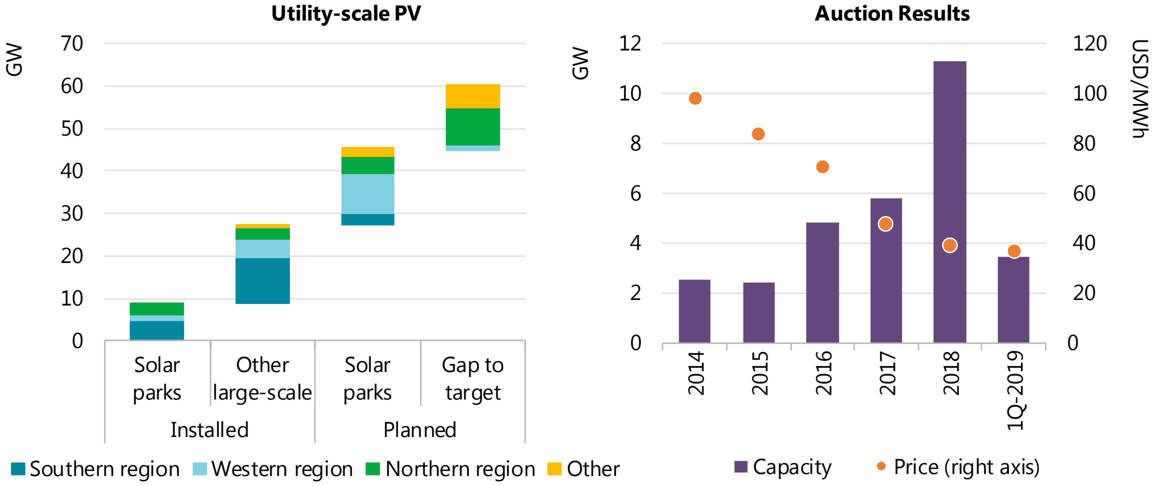
Notes: Acc. = accelerated case. R2018 = *Renewables 2018* forecast for 2018-23. R2019 = *Renewables 2019* forecast for 2019-24.

Competitive auctions are expected to drive the majority of solar PV growth. In 2018, India awarded 12 GW of **utility-scale PV** capacity, a 40% y-o-y increase, while the Ministry of New and Renewable Energy (MNRE) announced it will tender another 20 GW to 25 GW annually until 2021 to reach the 100-GW solar PV target by 2022. Auctions in the first eight months of 2019 allocated 6.6 GW of PV capacity, with bids averaging below INR 2.7/kWh (USD 40/MWh). These results appear to indicate that the introduction of safeguard duties for PV imports in 2018 and changes to the goods and sales tax (GST) have not resulted in system price hikes, possibly because module costs continue to drop globally and the solar park programme has facilitated project development.

Nevertheless, the government has extended the timeline for implementing the 40-GW solar parks from 2019-20 to 2022 due to land acquisition and grid connection delays. At the end of 2018, developers had finished installing 10 GW of solar PV and the government had chosen locations for another 16 GW, to be auctioned in 2019 (Figure 1.14). Timing of the allocation and tendering of the remaining 14 GW remains a key forecast uncertainty, however. Meanwhile, the preparatory work and grid connection of some solar parks has been delayed, and auction cancellations and retendering occur often due to undersubscription.

Most of the current installed solar PV capacity is in the southern region, where sites with higher irradiation are located and grid infrastructure is better. However, the majority of planned deployment will be in the western and northern regions, which have lower resource availability and where DISCOM financial health remains a challenge in many states (Figure 1.14). Overall, lack of progress under the Ujwal Discom Assurance Yojana (UDAY) programme introduces an element of forecast uncertainty. Key financial and operational targets were not met in the 2019 fiscal year (FY), and performance had deteriorated from FY 2018. For federal auctions by the Solar Energy Corporation of India (SECI) and NTPC Limited (with DISCOMs as the ultimate off-takers), the risk of payment delays is lower now that they are part of the tripartite agreement among the federal government, the states and the Reserve Bank of India, which serves as a payment security mechanism.

Figure 1.14 India: Utility-scale PV installations, targets and auction results



Note: *Other* includes the eastern and north-eastern regions.

Onshore wind capacity expands 31 GW as national and state-run auctions propel India towards its 60-GW target by 2022. In 2017-18, India successfully concluded auctions for 11 GW of onshore wind projects, with bids averaging USD 37/MWh to USD 40/MWh. Individual states also plan to launch independent wind tenders to meet their non-PV renewable purchase obligations, but possible auction delays, land disputes and grid connection problems are expected to hinder deployment. The accelerated case, which assumes the smooth running of auctions and timely grid connection, demonstrates an additional 2 GW of projects online by the end of the forecast period.

Table 1.2 India: Drivers, challenges and accelerated case assumptions

Country	Drivers	Challenges
India	High electricity demand growth; low bid prices for renewables; ambitious targets, combined with national and state support schemes.	Off-taker uncertainty for investors due to weak financial and operational performance of some DISCOMs; lack of access to financing or business models for distributed solar; grid congestion; land acquisition and permitting delays.
Accelerated case assumptions	Quicker implementation of solar park scheme; better DISCOM performance; timely implementation of green-energy corridor; and better uptake of rooftop and net-metering/self-consumption schemes.	

Rooftop PV deployment has been slow, with 3 GW of total capacity registered as installed in 2018 towards the 40-GW target for 2022. Commercial installations on government buildings and under the central public sector undertakings (CPSU) scheme (12 GW) are expected to lead growth in distributed PV. Installations on public sector premises offer opportunities for aggregation and economies of scale as well as for reducing the cost of supply for self-consumption and subsidy budgets for DISCOMs. Expansion remains slow, however, due to lack of commercial interest by DISCOMs and of viable business models or access to affordable financing.

Net-metering regulations for rooftop solar are in place across the country; however, the current retail tariff design incentivises customers with high electricity bills to install PV systems, which further erodes the revenues of the financially weak DISCOMs. New business models that retain a role for DISCOMs may be able to encourage them to support rooftop PV growth (CEEW, 2018). Recently introduced government financial support further encourages distribution companies to expand rooftop installations in their service areas. Additionally, rooftop PV projects are now eligible for housing improvement loans at preferential rates. Under the accelerated case, the success of these measures results in roughly twice the growth (30 GW) over the forecast period.

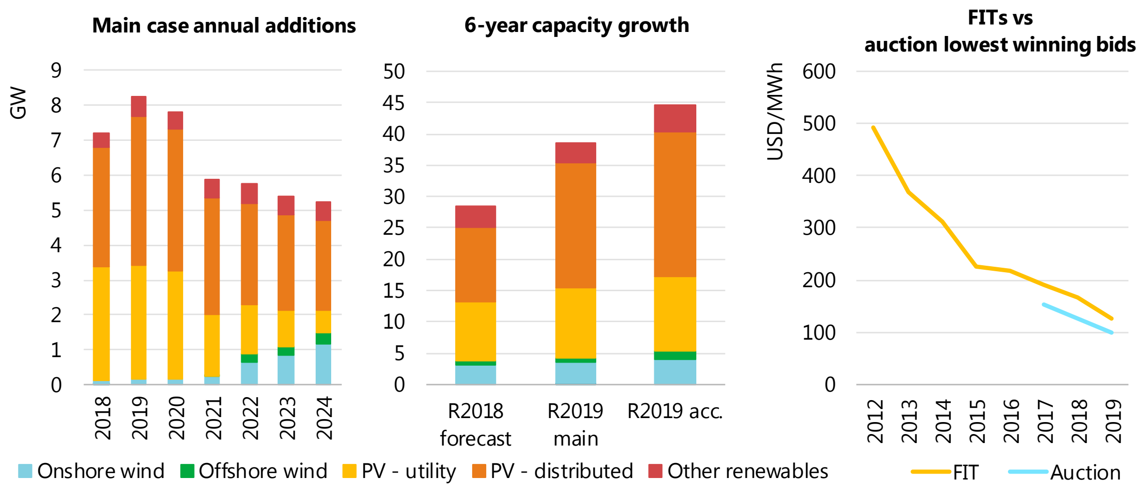
Hydropower gained new momentum with the government's decisions to declare large hydropower (over 25 MW) as renewable energy and to provide support to several very large projects that had been stalled due to social acceptance and financial obstacles. Many of these are expected to be commissioned only under the accelerated case due to the long lead times. Furthermore, the new project development schedule of the Ministry of Power has resulted in a downward revision to the main case, with more projects shifted to the accelerated case.

Bioenergy capacity increases by one-quarter (2.5 GW) by 2024, a slight upward revision from last year's forecast. The sugar and ethanol industry provides the most growth, through bagasse co-generation plants. Fiscal support and capital subsidies underpin capacity expansion of existing plants and greenfield investments.

Japan

In the main case, Japan's renewable energy capacity expands 33% (38 GW) over 2019-24, led by distributed solar PV and followed by wind and bioenergy (Figure 1.15). This growth is driven by FITs for all renewable technologies and auctions for utility-scale and commercial solar PV. Japan's forecast has been revised up from *Renewables 2018* to account for additional auction capacity and new rules enabling the participation of smaller projects. In addition, a lower cancellation rate for FIT-approved projects supports a more optimistic forecast for PV. Annual additions remain stable over 2018-20, as developers are expected to rush to lock in higher solar PV FITs before the new 2020 commissioning deadline. Japan's renewable energy growth could be 16% higher in the accelerated case, depending on how changes to the FIT rule affect the pace of PV deployment, which remains a major forecast uncertainty.

Figure 1.15 Japan: Renewable electricity forecast summary and auction results



Source: METI (2019a), Statistics of renewable energy in the feed-in tariff scheme.

Solar PV capacity increases the most, led by distributed applications. Overall, the forecast has been revised for three reasons: first, the government reduced the project capacity threshold for auction participation from 2 MW to 500 kW, including commercial applications, and announced an additional auction (for 750 MW) in 2019. Second, METI introduced a commissioning deadline (March 2020) for an estimated 12 to 19 GW (DC) capacity that received FIT approval before March 2015 (METI, 2019b). If these projects do not meet the deadline, their 2015 FIT rate will be cut by almost half. The main case forecast assumes that developers will rush to commission half of these projects during 2019-20. Third, the AC/DC ratio for projects coming online during the forecast period has been raised because developers are expected to opt for more revenue from the FIT scheme (METI, 2019c). However, PV growth could be 12% higher under the accelerated case, reflecting policy uncertainty over further FIT cancellations and new approvals, and the ability of auctions to contract additional capacity by attracting more competition.

Wind capacity is forecast to more than double by 2024, consistent with the *Renewables 2018* outlook, as lengthy permitting periods and grid connection availability remain key challenges. Although the government identified several offshore development zones in July 2019, specific project development areas and a competitive offshore wind auction timetable had not been announced at the time of writing. Accordingly, the main case forecast expects only a handful of small projects to become operational by 2024 (METI, 2019d).

Bioenergy capacity expands 54% (2.2 GW), mainly owing to projects previously approved under the generous FIT scheme and, to a lesser extent, by the auction scheme for new developers. The government will hold additional auctions for 120 MW of capacity in 2019, but the rules are subject to revision to attract more competition. In addition, coal and biomass co-firing is no longer eligible for FIT support as of 2019 (METI, 2019e).

Table 1.3 Japan: Drivers, challenges and accelerated case assumptions

Country	Drivers	Challenges
Japan	Improved and expanded auction scheme for utility and commercial-scale solar PV; attractive FIT scheme continues.	Relatively higher cost of renewables; grid constraints; lack of local acceptance; lengthy environmental assessment process for wind and geothermal projects.
Accelerated case assumptions	Faster onshore wind project approvals and accelerated offshore wind project under new law. Improved grid integration in areas with limited interconnections. Lower cancellation rate for FIT-approved projects.	

Korea

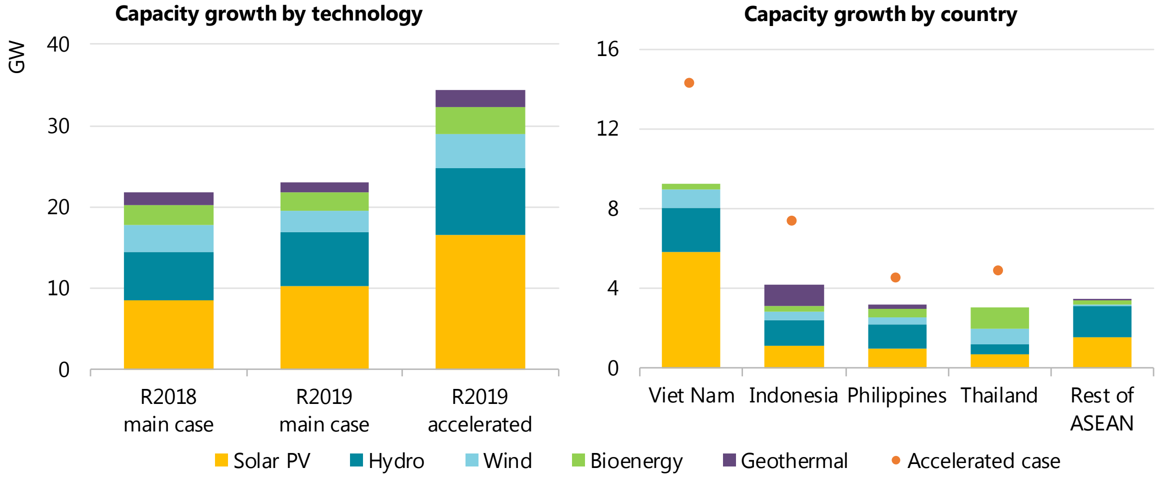
Korea's renewable energy capacity more than doubles to 40 GW during 2019-24, with solar PV providing 80% of the growth in the main case. This year's forecast is more optimistic than last year's owing to the government's new, more ambitious plan for 30-35% of electricity to be generated from renewables by 2040, compared with 7.6% today. This target is supported by a REC scheme and a temporary FIT programme. High REC (USD 66/MWh) and wholesale power prices (USD 93/MWh) provide generous remuneration for all renewables. Solar PV projects with storage will receive four to five RECs until 2020, encouraging rapid deployment of commercial applications in the short term (KNREC, 2019). Despite high remuneration, however, onshore and offshore wind deployment remain limited due to permitting and grid connection challenges. In the accelerated case, Korea's renewable capacity growth could be almost 35% higher than in the main case, depending on whether the Korean grid can integrate PV capacity more rapidly.

Association of Southeast Asian Nations

Renewable capacity in the ASEAN region is expected to expand by over one-third (22 GW) by 2024, led by solar PV and hydropower, followed by wind, bioenergy and geothermal (Figure 1.16). The forecast has been revised up slightly owing to the 2019 solar PV deployment boom in Viet Nam (+5 GW), despite slower-than-expected project development in Indonesia, the Philippines and Thailand in 2018. Viet Nam leads forecast growth because of its FITs for solar and wind energy, as well as regulatory changes improving the bankability of PPAs. If policy uncertainty and lack of access to financing are addressed in the region, renewable expansion could be 57% (35 GW) higher in the accelerated case across all technologies, with PV accounting for the largest additional increase.

Indonesia's forecast, with solar PV, hydropower and geothermal leading expansion, remains unchanged from *Renewables 2018* because regulatory challenges persist. The solar rooftop initiative and regulations for self-consumption are expected limit uptake due to unfavourable remuneration of excess generation and administrative burdens concerning solar energy system ownership. Project development in upcoming years will be driven by the 10-year procurement plan of PLN, Indonesia's national utility. If PLN prioritises renewable development and the government introduces more cost-reflective electricity pricing, growth could be 75% (over 7 GW) higher under the accelerated case.

Figure 1.16 ASEAN: Renewable electricity forecast summary by technology and country



Notes: R2018 = Renewables 2018 forecast for 2018-23. R2019 = Renewables 2019 forecast for 2019-24

Table 1.4 ASEAN: Drivers, challenges and accelerated case assumptions

Country	Drivers	Challenges
ASEAN	High demand growth; resource availability; energy diversification needs; FIT schemes.	Barriers to new market entrants; regulatory uncertainties; unfavourable energy pricing; lengthy processes; land scarcity or remoteness from grid access.
Accelerated case assumptions	Increased investor confidence through an improved policy-enabling framework. Accelerated grid expansion and improved regional interconnections. Regulatory clarity for corporate PPAs and rooftop PV business models.	

In **Thailand** renewable capacity is expected to increase by one-quarter, led by bioenergy, onshore wind and PV. The forecast for solar PV has been revised down from last year, as additional deployment under the new power development plan is expected only after 2024. Bioenergy growth is driven by the former FIT scheme, and this forecast also expects some additional capacity to come online under the scheme with a firm capacity requirement. Wind expansion is limited to the projects remaining under the phased-out FIT programme.

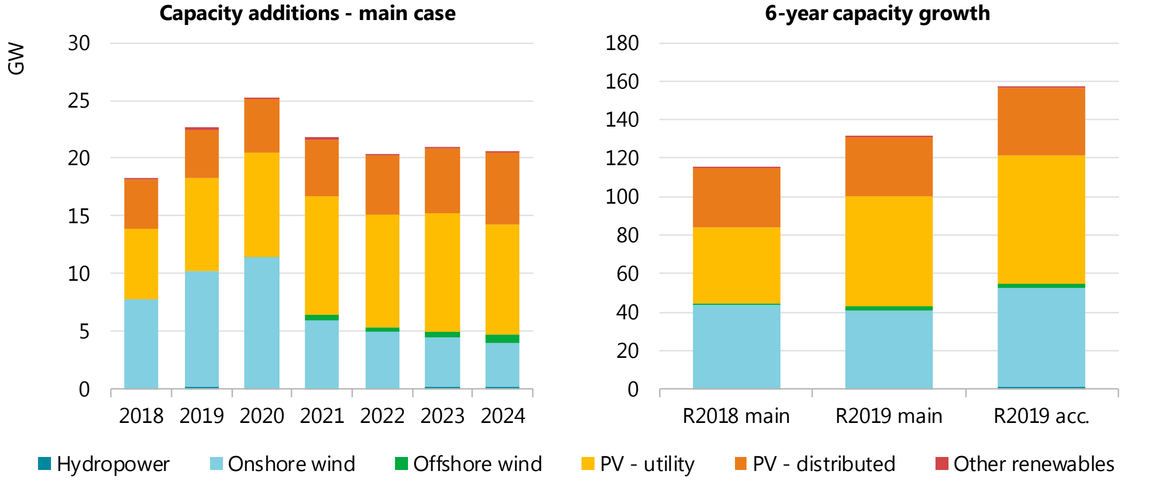
Not having had any notable developments or policy modifications, the **Philippines** is forecast to have 2.5 GW of renewable capacity additions, consistent with the *Renewables 2018* outlook. For the **rest of the ASEAN region**, the majority of hydropower is expected to be developed in Lao PDR (Laos), mostly for exporting to neighbouring countries, while solar PV is forecast to expand in most ASEAN markets, including Malaysia, Myanmar, Cambodia, Singapore and Laos.

North America

United States

In the US main case forecast, cumulative renewable capacity expands by almost 50% (132 GW) over 2019-24, mainly in solar PV and onshore wind, with smaller contributions from offshore wind and bioenergy (Figure 1.17). Federal tax credits, revised and extended state-level RPSs, and corporate wind and solar purchases continue to be the key drivers, supported by greater competitiveness. The forecast has been revised up, mainly for solar PV because the impact of import tariffs (introduced in 2018) on PV module prices remains limited due to the module supply glut. US annual capacity additions are expected to peak in 2020, as the PTC phaseout reduces onshore wind expansion afterwards. In the accelerated case, renewable capacity growth in the United States could be 20% higher, led by wind and solar. This would require clarification of the Environmental Protection Agency's (EPA's) new Affordable Clean Energy (ACE) rule (replacing the Clean Power Plan [CPP]), a greater number of corporate PPA projects and faster implementation of more ambitious RPS targets.

Figure 1.17 United States: Renewable electricity forecast summary



Notes: Acc. = accelerated case. R2018 = *Renewables 2018* forecast for 2018-23 (IEA, 2018). R2019 = *Renewables 2019* forecast for 2019-24.

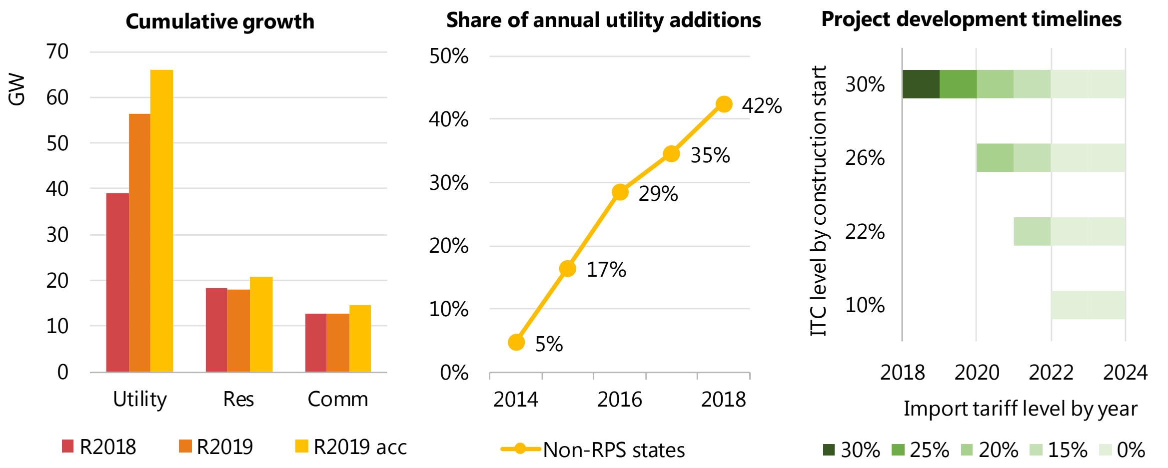
RPSs continue to create demand for renewables in states where targets have been raised and extended. In 2018, among other states, California increased its RPS to 60% by 2030, Connecticut to 40% by 2030 and New Jersey to 50% by 2030, while New York introduced an offshore wind procurement programme. These recent changes are expected to result in 15% additional wind and solar demand in 2024 (LBNL, 2019). Moreover, with wind and PV costs declining, corporate PPAs and merchant plants remain strong drivers of capacity expansion in Texas and the Midwest, while the Public Utility Regulatory Policies Act (PURPA) creates demand in the Southeast states in addition to the RPS.

Financing challenges for new wind and solar PV projects will have to be tackled during the forecast period. First, developers will be more exposed to market risks, as corporate PPA contract lengths are becoming shorter because companies wish to explore a variety of flexible contracts in the long term. Second, curtailment continues to be a revenue risk for developers in some markets (ERCOT, CAISO, etc.). Third, federal tax incentives are being phased out (a 10% input tax credit [ITC] remains for the commercial segment only), requiring developers to switch from tax equity to other forms of financing in the short term, which may raise financing costs. Fourth, corporate tax reductions have put pressure on the tax liabilities of corporations, reducing the number of tax equity investors.

Solar PV capacity more than doubles, expanding 88 GW over 2019-24, with utility systems accounting for two-thirds of growth (Figure 1.18). A decrease in system costs across all segments last year signals that improving economics for PV will remain a strong stimulant for expansion. Because the global oversupply reduced module prices, partially offsetting the increase from trade tariffs, the forecast has been revised upwards by 25% to reflect a more optimistic outlook for utility-scale systems, based on greater competitiveness in the South and policy-supported deployment in California and the Northeast.

While California remains the leader for utility-scale PV deployment, more competitive pricing means that an increasing share of growth is expected to come from markets that do not have strong state-level policies. The share of utility-scale capacity additions in markets that do not have a mandatory RPS (or that have already met one) has been increasing steadily since 2014, reaching 42% in 2018 (Figure 1.18). Most of this expansion occurred in Texas, Florida and other South-eastern states, prompted by good resource potential and falling system costs. This trend is expected to persist over the forecast period, as some utilities recently announced sizeable plans to build or competitively procure capacity to meet new power demand during 2020-24. Corporate PPAs also drive growth in this region as businesses seek lower tariffs or attempt to reach sustainability goals.

Figure 1.18 United States: Solar PV forecast summary



Notes: Acc = accelerated case. R2018 = *Renewables 2018* forecast for 2018-23 (IEA, 2018). R2019 = *Renewables 2019* forecast for 2019-24. Res = residential. Comm = commercial.

State-level RPSs remain an important catalyst for utility-scale growth, but mostly for markets in which costs are higher due to lower resource availability, higher labour and land costs, and permitting challenges such as in the Northeast. Rising RPS targets in Massachusetts, Connecticut and New Jersey are expected to result in additional demand for utility PV, and the end of the wind PTC is another strong incentive for growth in RPS markets because utilities will try to procure lower-cost solar PV to meet targets, particularly in the Midwest.

The largest forecast uncertainty is project development timelines, which have been disrupted by the phasing out of federal tax credits and import tariffs. It is uncertain how developers will try to optimise the two policies, as they have opposing impacts on project costs. They may try to leverage both the highest ITC level and lowest trade tariffs to optimise investment costs, which could result in longer lead times as developers start construction as early as possible and procure modules as late as they can before the commissioning deadline of 2024 (Figure 1.18). Utility-scale growth is 16% higher in the accelerated case, assuming it remains economically attractive after the ITC phaseout, especially in states that do not have strong policies. Faster expansion could also be achieved if grid constraints in Texas and the Midwest are addressed and development costs are reduced in the Northeast.

One-third of the PV increase is from **distributed solar PV**, encouraged mostly by attractive economics for self-consumption with remuneration for excess generation at or near retail rates. Greater policy support is another strong driver of growth. For the residential segment, California's rooftop mandate for new homes boosts expansion from 2020 onwards, while new RPS carve-outs for distributed PV in New Jersey, Maine and New York support more commercial expansion. Net-metering reforms and long connection times pose the greatest challenges, but overcoming these obstacles could result in 15% higher growth in the accelerated case.

In the main case, **onshore wind** accounts for over 30% (40 GW) of all US renewable capacity additions over 2019-24. In 2020, annual market size is expected to increase by 50% (11.5 GW) from 2018 additions, as developers need to commission all PTC-qualified projects. Annual deployment is considerably lower during 2020-24, but additional RPS demand and corporate PPAs remain the key drivers. The forecast takes financing challenges into account, especially those related to higher merchant risk and the PTC phaseout, as well as relatively slow grid infrastructure development in the Midwest and social acceptance challenges in the Eastern states that continue to impede faster growth. In the accelerated case, onshore wind growth could be 27% higher with a greater volume of corporate PPAs and innovative financing that would cut financing costs and make onshore wind more competitive.

Offshore wind capacity is forecast to expand 2 GW in the main case and up to 3 GW in the accelerated case, with this range reflecting lead-time uncertainty for projects that have already been auctioned in Massachusetts, New York, Rhode Island and Connecticut. Overall, the key challenges to offshore wind deployment are the lengthy permitting times and the considerable port facility investments required to accommodate offshore equipment.

The forecast for **bioenergy** remains stable from last year, at 600 MW of capacity growth. A peak in capacity additions is expected in 2019 from projects based on forestry residues and waste wood, aligned with the PTC phaseout schedule. From 2020 onwards, capacity additions decrease significantly and are based on forestry biomass, EfW and industrial projects, likely co-generation systems eligible for ITC support. Deployment prospects are limited in the absence of policy support, as many projects' generation costs will be above wholesale electricity prices if they cannot gain access to low-cost fuel supplies.

Table 1.5 United States: Drivers, challenges and accelerated case assumptions

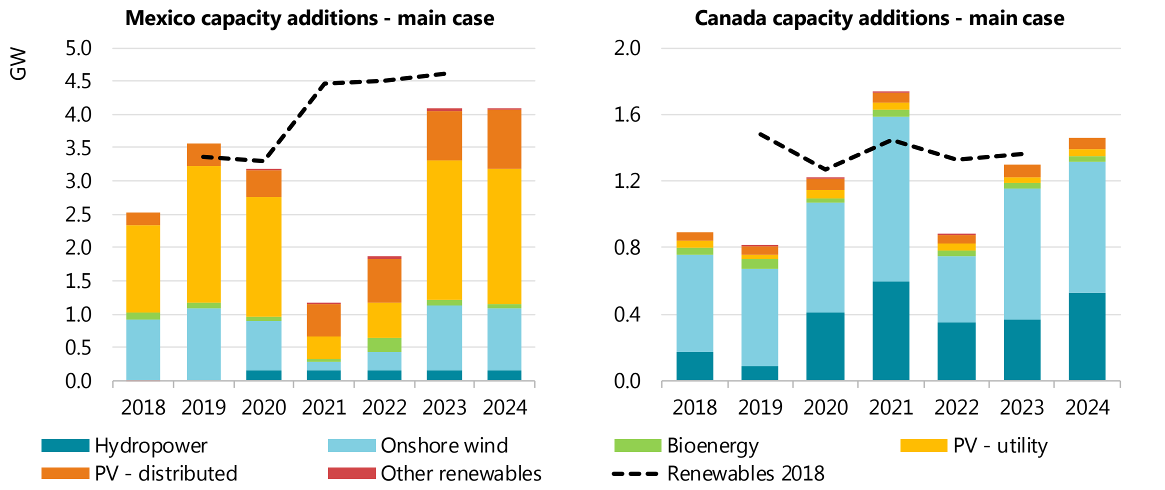
Country	Drivers	Challenges
United States	Federal tax credits; state-level RPSs and incentives for distributed PV; more corporate PPAs; declining investment costs for wind and PV.	Tax credit phaseout; uncertainty over ACE rule; curtailment risk in some regions; shorter PPA contracts; evolving distributed PV incentives in multiple states; lengthy offshore wind permitting process.
Accelerated case assumptions	Faster implementation of state-level RPSs and clarity over ACE rule. Limited impact of tax reform on financing costs. Accelerated deployment of merchant plants and corporate PPAs.	

Mexico and Canada

Mexico's renewable capacity reaches almost 40 GW by 2024 in the main case, with utility-scale solar PV dominating growth, followed by onshore wind, both driven by competitive auctions. The forecast has been revised down slightly, however, because the new government suspended the Clean Energy Certificate (CEL) auction scheme in 2019 for review (Figure 1.19). Consequently, both wind and solar PV capacity are forecast to expand more slowly in 2021 and 2022. The main case forecast assumes that new CEL auctions will resume in 2021, delivering additional wind and PV capacity to be commissioned in 2023-24.

The obligation for electricity retailers to cover a certain share of their sales with clean energy remains in place, and retailers need to buy CELs to prove they are meeting the government's renewables-share target. As no new CELs are being auctioned for the time being, private sector long-term auctions (CELPs) have emerged to aggregate CEL demand from obligated private retailers, which accounts for around one-third of Mexico's electricity sales. CELPs are expected to result in long-term contracts similar to official CEL auctions, providing long-term revenue certainty for developers. In addition to utility-scale projects, distributed PV supported by net-metering and net-billing is expected to contribute to renewable capacity expansion, especially in states where electricity prices are relatively high.

Figure 1.19 Mexico and Canada: Annual net renewable capacity additions



Mexico's renewable capacity expands 21% more in the accelerated case forecast, assuming auction rules and schedules are clarified rapidly in 2020. In addition, a larger corporate PPA market, along with private sector auctions and faster deployment of distributed PV, supports additional growth potential.

Canada's renewable capacity increases 7% (7.5 GW) in the main case, led by onshore wind and hydropower, with smaller contributions from distributed PV (Figure 1.19). The forecast has been revised down from last year due to recent auction cancellations in Ontario and Quebec as well as uncertainty over the future of renewable energy tenders in Alberta – despite low contract prices in the range of USD 25/MWh to USD 35/MWh. In May 2019, Alberta's new government announced that it would neither provide subsidies to renewables nor offer long-term contracts. As a result, Canada's onshore wind additions are expected to lose speed after 2021, with capacities coming online mainly from merchant plants encouraged by favourable economics in Alberta and competitive auctions in Saskatchewan. Smaller projects in British Columbia, where permitting and social acceptance remain challenging, will also contribute. The hydropower forecast remains unchanged from last year, with partial commissioning of the Site C plant.

Considering current policy uncertainties in several provinces, Canada's renewable capacity growth is almost one-third higher in the accelerated case, with onshore wind having the greatest potential for additional capacity expansion. Achieving this level of increase would therefore require clarification of Alberta's renewables policy and higher deployment of merchant and corporate PPA projects in Alberta, Ontario and Quebec.

Table 1.6 Mexico and Canada: Drivers, challenges and accelerated case assumptions

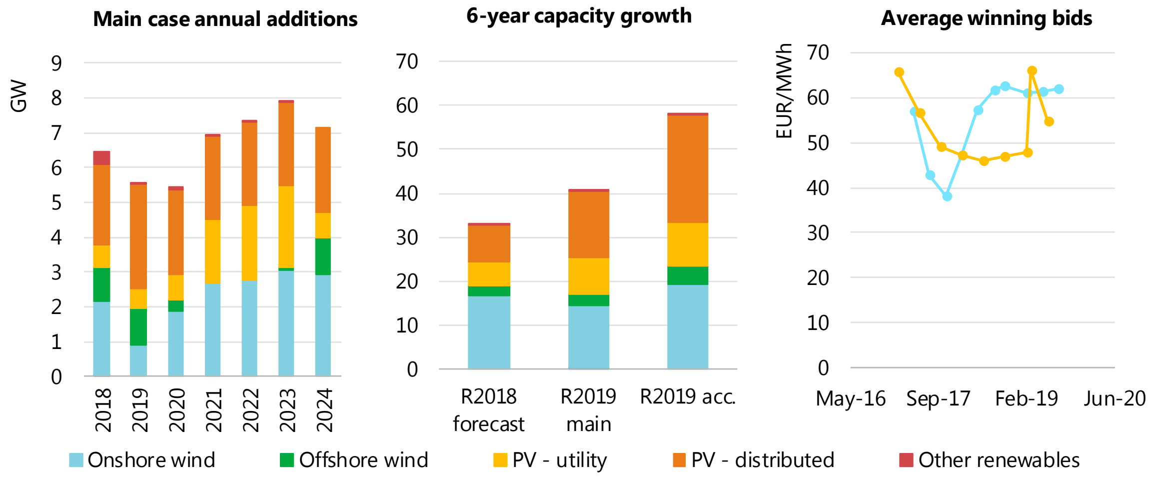
Country	Drivers	Challenges
Mexico	Clean energy target to 2024; growing number of corporate PPAs; increasingly competitive wind and solar PV.	Uncertainty over future green certificate auctions; weak grid infrastructure.
Accelerated case assumptions	Rapid uptake of corporate PPAs and merchant projects. Additional green certificate auctions in 2020 and 2021. Faster adoption of distributed PV systems.	
Canada	Renewable energy procurement targets in Alberta, Saskatchewan and British Columbia.	Reduced auction capacity in Quebec and Ontario; policy uncertainty in Alberta over future auctions.
Accelerated case assumptions	Resumption of Alberta's auction scheme with larger wind and solar capacities offered. Larger corporate PPA demand in the absence of auctions in Ontario and Quebec.	

Europe

Germany

Germany's renewable capacity expands 30%, led by solar PV and followed by onshore wind, offshore wind and bioenergy, mostly as a result of competitive auctions. The forecast has been revised up by 16% owing to a more optimistic outlook for solar PV, which stems from additional auctions and the increasing economic attractiveness of commercial systems. This upward revision for PV offsets the more pessimistic forecast for onshore wind that results from permitting challenges, local opposition and grid constraints (Figure 1.20). Annual onshore wind additions are expected to drop in 2019 due to a lull in project development caused by the long lead times resulting from onshore pilot auctions in 2017 that had favourable rules for energy co-operatives. A rebound in growth is forecast from 2020 onwards, peaking in 2023 as a result of the additional 8 GW of solar PV and wind auctions approved in the recently introduced Omnibus Energy Act. Expansion slows after 2023, however, due to a return to scheduled PV auction levels. Greater policy certainty and fewer administrative challenges therefore drive renewable capacity growth almost 50% higher in the accelerated case.

Figure 1.20 Germany: Renewable electricity forecast summary and recent auction results



Notes: Acc. = accelerated case. R2018 = *Renewables 2018* forecast for 2018-23 (IEA, 2018). R2019 = *Renewables 2019* forecast for 2019-24.

Solar PV growth has been revised up by 70% relative to *Renewables 2018* to account for the additional 4 GW of auctions introduced in the latest Omnibus Energy Act and the increasing economic attractiveness of commercial systems. Last year's forecast assumed only 2 GW of the proposed 4 GW of additional auctions would occur, given that the Energy Act was only at the draft stage. Since then, however, the Act has approved 4 GW and released a clear timeline for the tendering of them, which are now included in the forecast.

Nevertheless, policy uncertainty poses a risk to faster PV growth. For utility-scale systems, the auction schedule beyond 2021 is unknown. The main case assumes that capacity additions of 600 MW per year will continue after the auctions are over in 2021, but land procurement is emerging as a challenge, contributing to rising bid prices in recent rounds (Figure 1.20). Growth over the forecast period could be 20% higher if auction volumes increase and the economic attractiveness relative to power prices triggers corporate PPA growth, which has been limited to one 8-MW project to date.

For distributed PV, falling module costs and high electricity prices have made self-consumption more attractive, with remuneration of excess generation at value-based tariffs. This is largely the reason for the increase in commercial system growth in 2018, which was more than double that in 2017. Distributed PV expansion depends on the extension of support for remunerating electricity exported to the grid above market prices. Support was set to end when cumulative installed PV capacity reached 52 GW, but the recently released 2030 Climate Plan proposes to lift the cap and extend support. The proposal still needs to be ratified by parliament, but the main case forecast expects this provision to be passed.

Box 1.1 To what extent does the EU 2030 renewable energy target influence the Renewables 2019 renewable capacity forecast?

The European Union's target of 32% renewable energy in final energy consumption by 2030 is one of the main drivers for the region's renewable capacity growth beyond 2020.[3] Yet the extent to which it influences the renewable electricity forecast is mixed because achieving the EU-wide goal depends on the specific policies of the member states, which are currently at various stages of implementation.

The EU 2030 target was set in a revision of the Renewable Energy Directive (RED). Although an EU directive is a legal act that sets goals member states must achieve, it gives them the autonomy to decide how to transpose the directive into national law. The first RED[4] set binding national targets to achieve an EU-wide goal of 20% renewables by 2020.[5] The national policies and support measures countries implemented to reach their 2020 targets are what underpin the majority of the Renewables 2019 forecast for the European Union up to the year 2020.

Beyond 2020, the EU 2030 target is expected to be a key stimulus for renewable capacity growth. However, the policies most member states will use to reach the 2030 target have not yet been finalised and therefore represent a forecast uncertainty. Unlike for the 2020 target, the revised RED[6] did not set individual binding targets for member states. Instead, it requires that member countries propose their own national contributions to the EU 2030 target, accompanied by a description of planned policies to support the contribution through integrated National Energy and Climate Plans (NECPs). Member states had submitted their draft NECPs by the end of 2018, and final proposals are to be submitted by the end of 2019. However, the time frame for finalising the NECPs of all states was not known at the time of writing.

Nevertheless, independent of their draft NECPs, some member states already have policy frameworks that extend beyond 2020. The Renewables 2019 main case forecast takes account of those policies that have already been adopted, and in some cases those that have been announced and planned to the extent that there is a realistic chance of being adopted and implemented within the forecast period.

Due to an increasing number of permitting challenges, forecast **onshore wind** capacity expansion has been revised downwards by 14% relative to *Renewables 2018*. Tighter state-level permitting requirements, less availability of regional development zones, and a greater number of legal challenges stemming from local opposition have led to longer processing times for permits (now up to two years instead of one) (WindEurope, 2019a). As a result, fewer permitted

[3] Forecasts for the European Union are made at the individual member state level and then summed to get the EU aggregate. At the time of writing, the United Kingdom was a member of the European Union (EU); thus, for the purpose of this analysis the United Kingdom is included in EU aggregates.
[4] Directive (EU) 2009/28/EC.
[5] Renewable energy in final energy consumption.
[6] Directive (EU) 2018/2001.

projects have been up for bid in auctions, causing the last four auctions to be undersubscribed. Of the 2.7 GW offered since October 2018, only half (1.3 GW) have been awarded, at an average of EUR 62/MWh. Therefore, the number of permitted projects available for future auctions is a key forecast uncertainty, and the pace at which older plants are being decommissioned, which averaged 280 MW per year during 2013-18, also challenges net annual growth.

As older plants reach the end of their lifetimes, decommissioning decisions will largely depend on the business case for repowering, which in turn will be affected by the different risks associated with the revenue options available and land constraints for newer and larger turbines. Capacity growth in the accelerated case is therefore 36% higher assuming that permitting bottlenecks are resolved and that decommissioning of older plants is avoided through corporate PPAs that extend their lifetimes. (For instance, in 2018 a car manufacturer signed a five-year PPA with 6 GW of ageing wind plants to extend their lifespans after the 20-year FIT support ends.)

Table 1.7 Germany: Drivers, challenges and accelerated case assumptions

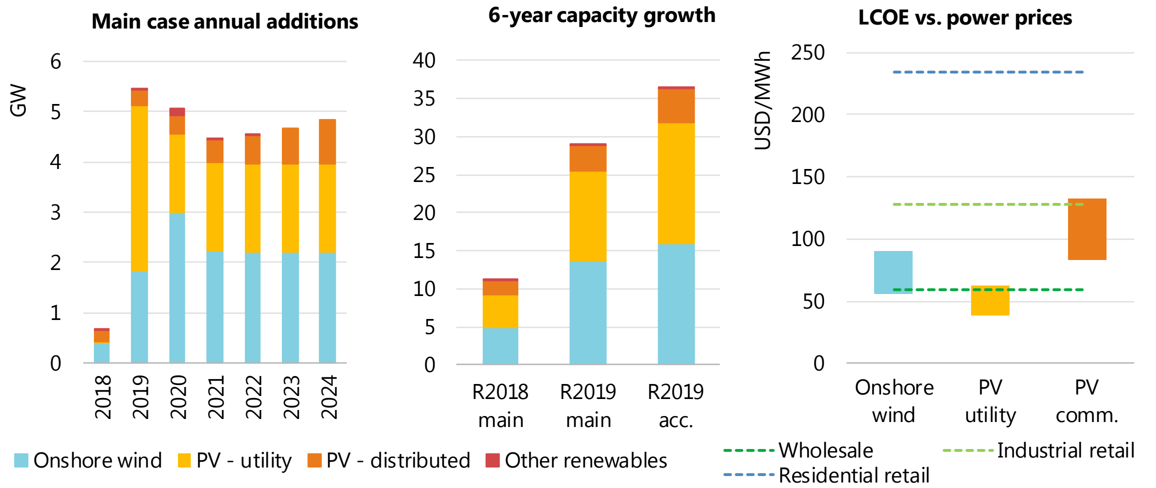
Country	Drivers	Challenges
Germany	Long-term climate and renewable energy goals; supportive policy environment for utility-scale and distributed technologies.	Permitting restrictions for onshore wind; transmission grid congestion; rising land procurement costs.
Accelerated case assumptions	Faster wind project approvals; fewer delays from litigation; and minimal decommissioning. Grid Expansion Acceleration Act is passed and network expansion gains speed. Support for distributed solar PV and behind-the-meter storage is extended.	

Spain

Spain's renewable capacity is expected to increase by 56%, more than double that expected in *Renewables 2018*, owing to a more supportive policy environment and the increasing competitiveness of renewables (Figure 1.21). This upward revision stems from a new proposal for annual renewable capacity auctions, better long-term certainty over the support mechanism for auctions that guarantees a minimum rate of return, corporate PPA market growth, and policy changes that raise the economic attractiveness of self-consumption. With these developments, Spain becomes the second-largest growth market in Europe, led by solar PV, onshore wind and bioenergy. Annual additions peak in 2019 as the commissioning deadlines of previous auctions are reached, then remain stable, in line with the pace of newly proposed auctions supported by growth from corporate PPAs.

Policy support has been reinforced with proposed new renewable capacity targets for 2030 and plans to achieve them with competitive auctions. The country's NECP targets an additional 50 GW of PV and wind to be installed between 2020 and 2030, and the draft of a new climate law released in November 2018 proposes the auctioning of at least 3 GW of renewable capacity per year during 2020-30. However, the implementation pace of proposed auctions and their design remain key forecast uncertainties. An increasing share of annual growth will be from unsolicited PPAs with both utilities and corporate buyers as the generation costs of utility-scale PV and onshore wind begin to fall below wholesale electricity prices. Yet financing these projects will continue to be a challenge, albeit to a lesser extent as lenders become more comfortable with riskier projects. Expansion of these projects in the main case forecast depends on electricity prices remaining high, but how downward pressure from increased renewable generation, future demand and retiring plants will affect prices remains a forecast uncertainty.

Figure 1.21 Spain: Renewable forecast summary and wind and PV generation costs and power prices



Notes: Acc. = accelerated case. R2018 = *Renewables 2018* forecast for 2018-23 (IEA, 2018). R2019 = *Renewables 2019* forecast for 2019-24.Comm = commercial. LCOE = levelised cost of electricity. Residential retail tariff represents the variable rate. Prices are most recent year available.

Sources: BNEF (2019), Prices, Tariffs, and Auctions (database). IEA (2019), Energy, Prices, and Taxes 2nd Quarter 2019 (database).

Distributed solar PV capacity expands twice as much as forecast in *Renewables 2018*, as recent policy changes are expected to make self-consumption more economically attractive, particularly for commercial systems. In October 2018, a Royal Decree was passed to remove the charges on self-consumed generation for PV systems of > 100 kW; with this change, commercial generating costs could be as much as 35% below industrial retail prices in 2018. Simplified registration procedures for small systems and the introduction of shared generation also support the expectation of higher growth, as does a more optimistic forecast for residential PV owing to a new self-consumption proposal to remunerate excess generation for systems of < 100 kW. However, limited consumer confidence and uncertainty over future retail prices may challenge faster growth.

Overall renewable capacity growth could be one-quarter higher if the full 3 GW of annual auctions proposed are implemented and the gap between wholesale electricity prices and renewable generation costs widens enough to trigger faster PPA growth and even pure merchant plant deployment.

Table 1.8 Spain: Drivers, challenges and accelerated case assumptions

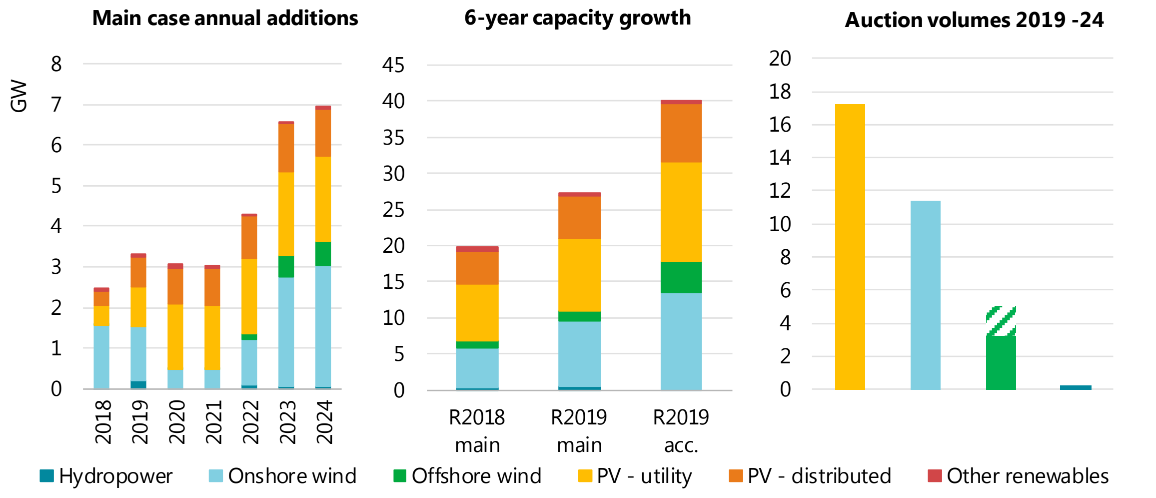
Country	Drivers	Challenges
Spain	Targets combined with support schemes; rising wholesale power prices; improved economics for distributed PV; removal of administrative barriers.	Policy uncertainty; capacity oversupply; limited interconnections.
Accelerated case assumptions	Full and timely implementation of climate proposal for at least 3 GW of renewable capacity annually starting in 2020. High wholesale and retail power prices. Accelerated deployment of merchant plants and corporate PPAs.	

France

Led by solar PV and followed by onshore wind, offshore wind, bioenergy and hydropower, France's renewable capacity is expected to expand 52% (27 GW) (Figure 1.22). Renewable capacity targets, accompanied by competitive auctions and a supportive environment for self-consumption from distributed solar PV, are the main catalysts for growth. However, the pace of deployment is challenged by complex administrative procedures and lengthy litigation prompted by local opposition to utility-scale projects. Growth could be almost 50% higher if these issues are resolved by the government's recent efforts to improve the regulatory framework.

Overall, the forecast is more optimistic than that of *Renewables 2018* as a result of increased policy support and extension of the auction schedule to 2024 proposed in the new draft of the long-term energy plan (PPE). The plan, announced in November 2018, introduces new targets for 2028 and a schedule for auctioning 32-33 GW of renewable capacity over 2019-24. These volumes are higher than the assumptions for future auction amounts made in *Renewables 2018*, resulting in an upward revision of 40%. Annual additions increase in 2019 as residual projects from older support schemes are commissioned, but are expected to stall in 2021 due to a slowdown in onshore wind caused by regulatory uncertainty over permitting and ongoing legal challenges (Figure 1.22). Annual deployment rebounds from 2022 onwards owing to reforms aimed at reducing administrative barriers.

Figure 1.22 France: Renewable electricity forecast summary and auction volumes



Notes: Acc. = accelerated case. R2018 = *Renewables 2018* forecast for 2018-23 (IEA, 2018). R2019 = *Renewables 2019* forecast for 2019-24. Shading above offshore wind bar in the far right graph represents the upper range of capacity that could be auctioned.

Solar PV capacity almost triples over 2019-24, driven mostly by competitive auctions for PPAs for both utility-scale and large commercial systems. The forecast has been revised up by almost one-third from last year to account for the increased policy support of the latest PPE, which raised auction volumes to meet the new targets of 36 GW to 45 GW by 2028. Long project lead times pose a challenge to annual growth, however. Construction delays stemming from complex approval processes and local opposition result in highly uncertain project development timelines, part of the reason that the most recent rooftop auction was undersubscribed for the first time. In addition to auctions, rising electricity prices are expected to encourage utility-scale expansion from corporate PPAs, whereas net-metering for small commercial systems (< 100 kW) and FITs for residential systems spur distributed PV growth. Solar PV capacity additions could be one-third higher if the initiatives outlined in the executive #PlaceAuSoleil plan, which aims to accelerate PV deployment, are effective. The plan outlines 30 measures intended to minimise project development times for utility PV and encourage more self-consumption by simplifying the approval process, increasing local support and allowing third-party business models.

Although **onshore wind** capacity is expected to increase by 60% permitting delays challenge the pace of deployment, putting the 2023 target (25 GW) at risk. In 2017, a court ruling appointed a new institution responsible for environmental permitting but did not specify how the transition would affect previously permitted projects and what the process would be for new applicants. As a result, new permits have stalled, causing Round 2 of the wind auctions to be undersubscribed and Round 3 to be delayed. In addition to the permitting challenges, the lead times for onshore wind development in France are typically long due to lengthy legal processes. The pace of project realisation will depend on how the new measures passed in 2018 reduce the administrative and legal hurdles that have slowed development so far. Growth under the accelerated case is near 50% higher, conditional on permitting delays being resolved and auctions being fully subscribed.

Offshore wind capacity is forecast to reach 1.3 GW by 2024, but most of the growth is not expected to begin until 2022 – ten years after the winners of auction rounds 1 and 2 were selected – due to the legal challenges faced by the projects. Growth could be more than three times as high in the accelerated case should projects from upcoming auctions have shorter lead times owing to less local opposition and faster permitting. Competitive auctions for small **hydropower** and a PSH project will drive the 400 MW increase expected over the next five years. Meanwhile, the **bioenergy** forecast is less optimistic than in *Renewables 2018* because the latest targets for 2023 have been revised downwards and the future of support schemes for large-scale systems has been uncertain since tendering ended in 2018.

Table 1.9 France: Drivers, challenges and accelerated case assumptions

Country	Drivers	Challenges
France	Higher renewable energy targets in the PPE, supported by auctions and financial incentives; new regulations to increase self-consumption.	Permitting uncertainty for onshore wind; complex administrative and long legal processes; local public opposition.
Accelerated case assumptions	Shorter project lead times resulting from streamlined administrative processes; permitting uncertainty resolved for onshore wind and fewer litigation delays. Increased competition and greater regulatory clarity ensures that auctions are fully subscribed. Falling costs improve the economics of self-consumption.	

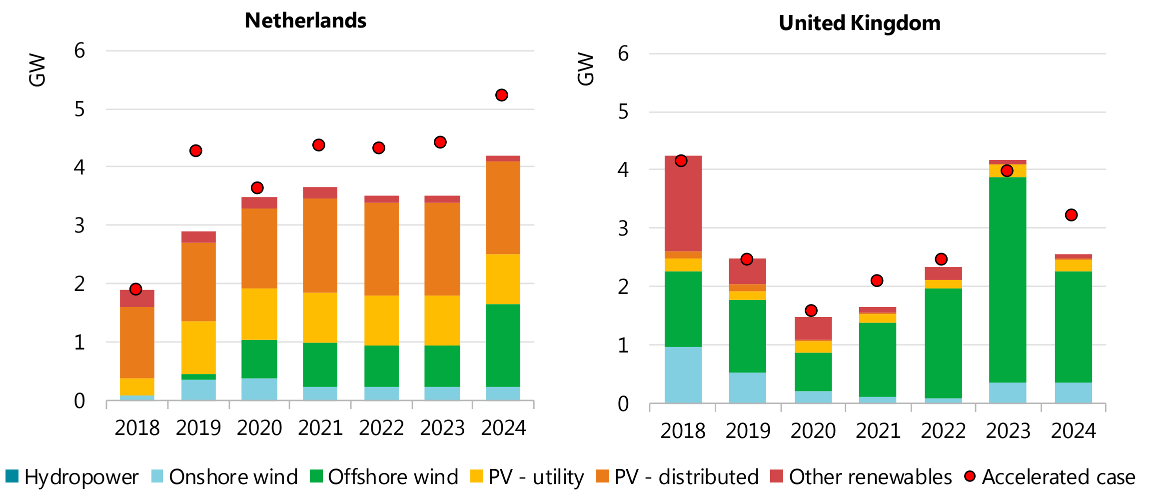
The Netherlands and the United Kingdom

Renewable capacity in the **Netherlands** triples over 2019-24, with 21 GW of growth – a significant upward revision from last year's forecast. Solar PV additions hit a record 1.5 GW in 2018 (Figure 1.23), and capacity is anticipated to grow 14 GW by 2024. Sustainable Energy Production (SDE+) auctions drive deployment of utility and commercial projects, which account for most capacity growth. Although the SDE+ is set for revision in 2020, the forecast assumes it continues to offer support for solar PV given the need to scale up renewable electricity generation to 2030 as outlined in the country's NECP. The residential PV market accounts for the remaining 20% of growth owing to attractive economics under the net-metering scheme.

The Netherlands Offshore Wind Energy Roadmap aims to deliver 11.5 GW of projects by 2030. Tenders already conducted are anticipated to raise capacity 4.3 GW by 2024, and further tenders are scheduled for 2019 and 2021. Onshore wind capacity expands by 1.7 GW, supported by the SDE+, but is anticipated to fall short of the 6-GW target by 2020 due to barriers associated with public acceptance and, to a lesser extent, grid connection and land fees. Bioenergy capacity grows 900 MW from biomass co-generation and biogas projects awarded in SDE+ auctions. In addition, four major co-firing projects awarded SDE+ subsidies are anticipated to deliver 7 TWh of biomass generation by 2020.

Renewable capacity in the accelerated case increases further still, mainly from solar PV, assuming that generation costs fall even more, facilitating greater deployment under SDE+ budgets. Greater grid capacity for solar PV connections in the north-eastern provinces and other key areas would also spur higher utility PV deployment.

Figure 1.23 The United Kingdom and the Netherlands: Net renewable capacity additions



The **United Kingdom's** renewable capacity is anticipated to expand 30% (14.3 GW) over 2019-24. Offshore wind is central to the UK government's industrial strategy and accounts for more than 70% (10 GW) of growth, with the plant-commissioning schedule dictating annual additions (Figure 1.23). The Contract for Difference (CfD) scheme drives deployment as capacity awarded in the 2015 and 2017 auctions is commissioned, with the 2019 CfD auction expected to deliver further projects in 2023 and 2024. Offshore wind provided around 8% of the United Kingdom's electricity supply in 2018, and long-term growth prospects are strong, as a joint government-industry deal aims for offshore wind to meet 30% of UK electricity demand by 2030.

Onshore wind capacity expands 1.7 GW because of the eligibility of wind farms on remote islands to compete in the 2019 CfD auction, and project development from corporate PPAs. Most deployment is in Scotland because of its good wind resources. Increasing interconnector capacity between the United Kingdom and several European countries over the forecast period supports the deployment and grid integration of onshore and offshore wind. Bioenergy capacity is anticipated to grow 1.3 GW by 2024, including a 300-MW electric co-generation plant with CfD support due to be commissioned in 2020.

Over the forecast period, solar PV expands 1.2 GW – equivalent to only 11% of the capacity added during 2013-18 due to scaled-down renewable energy policy support in the United Kingdom since 2015. The closure of the FIT scheme to new applicants in early 2019 has left solar PV without any form of policy support, although the corporate PPA market is anticipated to encourage some utility PV deployment.

Beginning in 2020, the Smart Export Guarantee scheme will obligate electricity suppliers with more than 150 000 domestic customers to offer at least one export tariff for half-hourly metered renewable generation; eligible technologies include solar PV up to 5 MW of capacity. Although the tariff offered must always be above zero, it is not currently clear whether the rates will be high enough to raise consumer deployment. Therefore, this new policy is not anticipated to significantly boost household PV deployment in the forecast.

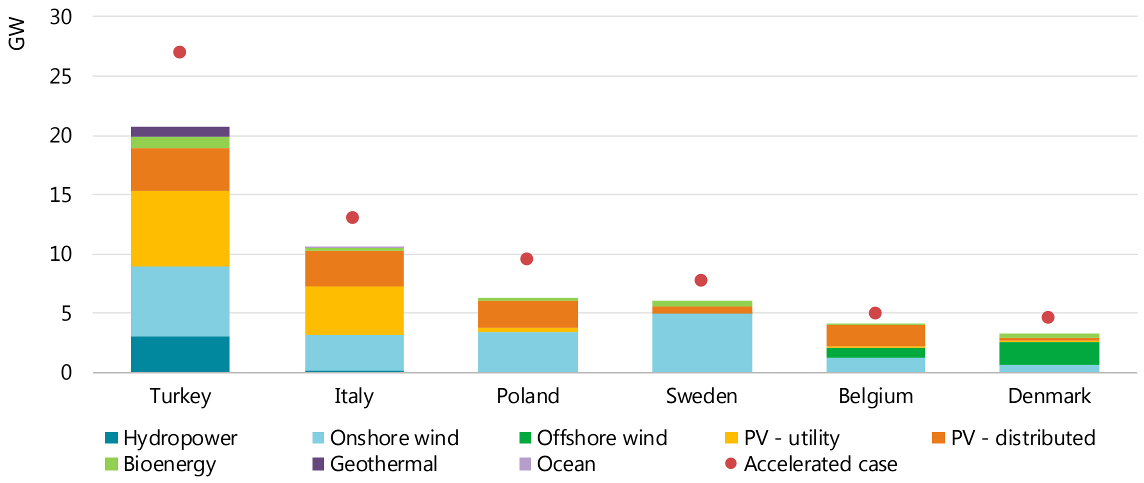
The accelerated case assumes the delivery of a 100-MW PSH project, more bioenergy from EfW projects and further onshore wind from greater deployment of remote island wind.

Other countries in Europe

Turkey's renewable capacity increases 49% (21 GW), primarily in solar PV, onshore wind and hydropower (Figure 1.24). The forecast has been revised up, mainly for distributed solar PV, because the government approved a new framework for self-consumption and remuneration of excess generation at retail rates for residential, commercial and industrial applications. In addition, the new regulation raised the size eligible for support from 1 MW to 5 MW. For onshore wind, annual competitive auctions (YEKA) are expected to drive expansion, along with projects that received FIT licences but are waiting for final permitting and transmission capacity to be auctioned. The forecast expects limited hydropower growth after 2020 in the absence of planned development beyond the commissioning of large-scale projects currently under construction. Overall, affordable financing remains a key challenge, especially due to around 50% depreciation of the Turkish lira since January 2018 and nominal interest rates of close to 25% (June 2019) on loans. Turkey's renewable capacity could expand 31% more quickly if macroeconomic indicators improve, the new distributed PV regulation is implemented smoothly (leading to faster deployment), and more capacity is allocated under YEKA tenders.

Renewable capacity in **Italy** is expected to grow 18% (10 GW) over 2019-24, led by solar PV and onshore wind. The forecast has been revised up to account for the strengthened role of utility- and commercial-scale PV and onshore wind under the new 2030 NECP. The pace of project implementation under the new renewables decree remains a forecast uncertainty, however, because the first auction has already been delayed. The forecast is 24% higher under the accelerated case, assuming the announced auction schedule is adhered to and results in the timely commissioning of planned projects.

Figure 1.24 Other Europe: Renewable capacity expansion, 2019-24



In **Poland**, renewable capacity increases 65% to 16 GW by 2024 – a 23% upward revision from last year's forecast – reflecting the increasingly supportive regulatory environment for onshore wind and auctions. Poland reduced taxation for wind projects in 2018, and it is expected to relax the strict distance requirement for future projects. These improvements, coupled with high capacity factors, resulted in onshore wind winning all capacity (1 GW) in the 2018 hybrid onshore wind-PV auction. This year's more optimistic forecast is also supported by a recent draft amendment to the Renewable Energy Act, which proposes higher wind and PV capacity volumes to be auctioned in 2019 and shorter commissioning deadlines to accelerate deployment to meet the 2020 targets. However, a lack of auction timelines post-2020 remains a forecast uncertainty and hampers faster growth. Expansion could be more than 50% higher with regular auction rounds and faster uptake of distributed PV for self-consumption, provided the proposal to include commercial systems in net-metering is passed in 2019.

Led by onshore wind, **Sweden**'s renewable capacity expands 21% (6 GW), an upward revision owing to higher corporate PPA activity for onshore wind. Plus, building requirements and the tax credit will continue to spur distributed PV deployment. Growth in the accelerated case is one-quarter higher, assuming regulatory changes address PV ownership limitations and shorter permitting and consent processes for onshore wind are implemented.

Belgium's renewable capacity is forecast to grow 42% (4 GW), with residential PV and on- and offshore wind expanding the most. This is a downward revision from last year due to the accelerated commissioning of offshore wind projects in 2018, although state-level instruments for implementing the federal plan are a forecast uncertainty. Growth is 22% higher in the accelerated case as the economic attractiveness of distributed PV improves.

Renewable energy capacity in **Denmark** rises 37% (3 GW) over 2019-24, led by offshore and onshore wind, solar PV and bioenergy. According to its 2018 national energy agreement, Denmark plans to reduce the number of currently operating onshore wind turbines by half over the next decade to tackle social acceptance issues, raising offshore wind deployment instead. Despite the introduction of hourly accounting of self-consumption and the end of net-metering, distributed PV is expected to make up three-quarters of PV growth, while the remaining comes from utility-scale projects through competitive, technology-neutral auctions. The pace of growth could be limited, however, if the fixed grid fee reduces economic attractiveness.

Concerning bioenergy, municipality-based co-generation projects drive deployment. Denmark's capacity growth is 40% higher under the accelerated case, which assumes higher PV expansion resulting from greater distributed PV self-consumption and additional auctions for utility-scale projects, as well as twice the bioenergy deployment of the main case forecast.

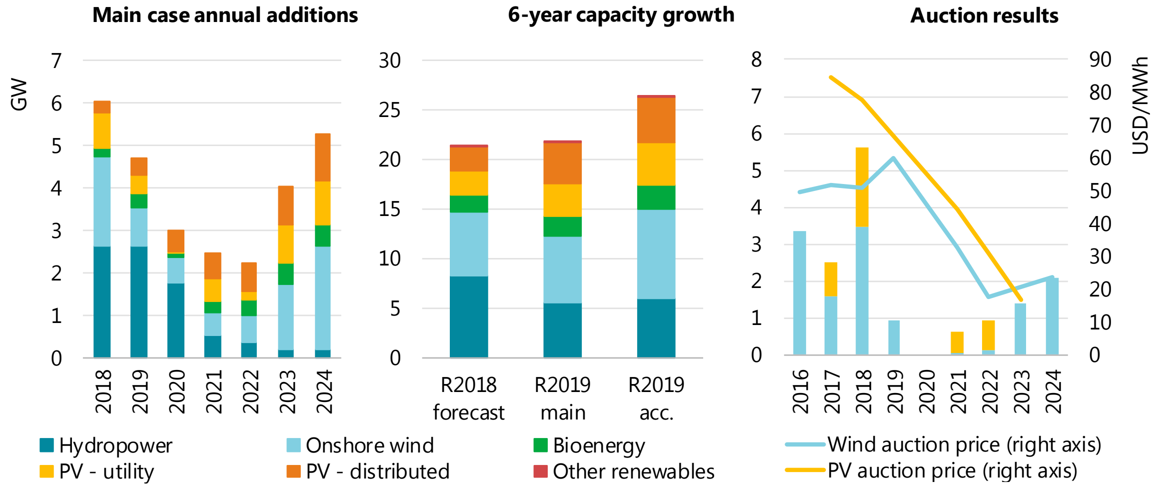
Latin America

Brazil

Renewable capacity expands 16% over 2019-24 as a result of electricity auctions for utility-scale renewables and the emergence of a distributed PV market. Brazil's onshore wind and solar PV forecast is more optimistic than last year's owing to slow but continuous improvement in macroeconomic indicators, a new auction schedule and a slate of emerging merchant projects, combined with corporate PPAs. Annual additions dip in 2022 because hydropower expansion is significantly slower after the commissioning of large-scale projects (mainly Belo Monte) in 2019-20 (Figure 1.25). Capacity expansion is expected to gain speed again after 2022 with additional wind, solar and bioenergy auctions.

For the first time, **onshore wind** overtakes hydropower to claim the largest capacity growth over the forecast period. In 2018, wind projects won contracts for over 2 GW of capacity to be commissioned in 2022 and 2024. Low contract prices (USD 20/MWh) were obtained in spite of the new auction design that shifts balancing responsibility from distribution companies to developers, increasing project risks. For utility-scale **solar PV**, contract prices fell to under USD 20/MWh, more than 50% lower than in previous auctions for projects to be commissioned in 2022-23 (Figure 1.25). These drops result from suppliers offering competitive equipment prices to make up for low demand caused by limited auction capacity since 2016.

Figure 1.25 Brazil: Renewable forecast summary and auction results by commissioning date



Notes: Acc. = accelerated case. R2018 = *Renewables 2018* forecast for 2018-23 (IEA, 2018). R2019 = *Renewables 2019* forecast for 2019-24.

Wind and solar PV developers are increasingly considering selling electricity on the spot market, where 30% of the country's electricity consumption is currently traded. The forecast expects that developers will also establish merchant plants (with 5- to 15-year PPA contracts) at these competitive prices. Outside of auctions, however, obtaining affordable financing is still a key challenge, as is ensuring grid connections. The accelerated case for wind and PV takes not only larger auction volumes (dependant on higher electricity demand) into account, but also accelerated deployment outside of the auction scheme.

Table 1.10 Brazil: Drivers, challenges and accelerated case assumptions

Country	Drivers	Challenges
Brazil	Competitive auctions with long-term PPAs; increasing liquidity in the spot market enabling merchant projects; net-metering for distributed PV.	Availability of affordable financing; higher project risk with changing auction rules; weak grid infrastructure in some states.
Accelerated case assumptions	Additional auction capacity spurred by more optimistic electricity demand. Higher merchant capacity and an increasing number of corporate PPAs. Faster adoption of distributed solar PV.	

Distributed solar PV slowly emerges as a key market segment over the forecast period owing to annual net-metering especially in states where electricity prices are relatively high and state-level tax exemptions exist. A new regulation has introduced virtual net-metering, which enables PV owners to receive retail credits for their generation consumed at a different location under the same company name or social security number; however, the energy regulator (ANEEL) has proposed additional distribution grid charges for PV owners, based on deployment caps. The new regulation therefore presents a forecast uncertainty, as distribution charges can make up 30-45% of retail electricity bills, which could alter the economics of solar PV. Potential for distributed PV expansion in the accelerated case is 12% higher than in the main case, based on the assumptions that proposed additional charges do not harm the economic attractiveness of residential and commercial applications, and that costs continue to decline, facilitating adoption.

Bioenergy capacity in Brazil expands 2 GW, a slight upward revision from last year's forecast given the resumption of renewable electricity auctions that include bioenergy. In addition, the federal RenovaBio plan to boost the production of transport biofuels is due to come into force in 2020, anticipated to result in additional bagasse-based co-generation capacity from both existing facilities and new sugar and ethanol mills. Under the scheme, ethanol producers that use higher levels of renewable process energy will receive more tradeable decarbonisation certificates. Biogas and the occasional larger industrial projects (e.g. from pulp and paper) also contribute to the forecast.

Argentina and Chile

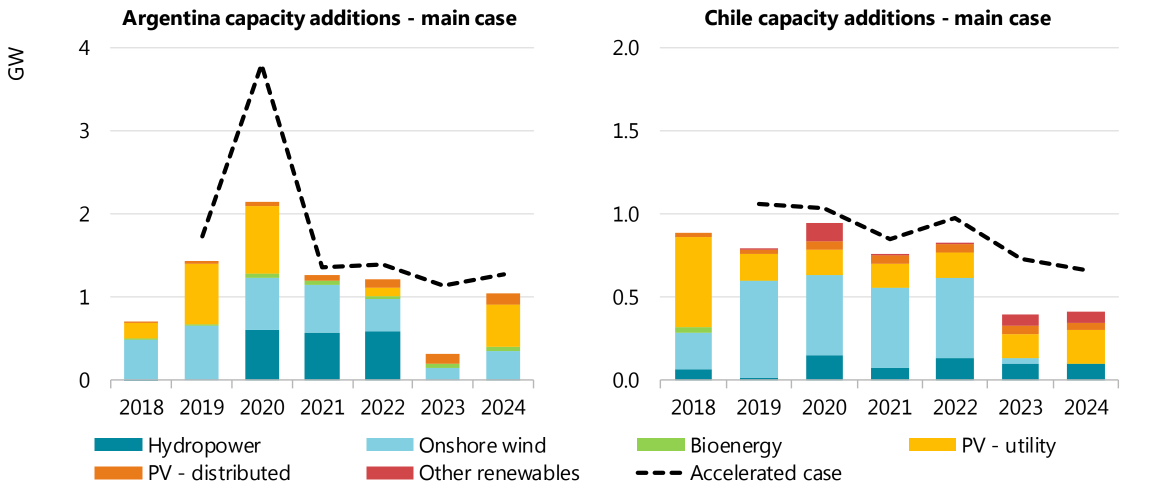
Argentina's renewable capacity is set to expand 52% (7.5 GW), in line with the *Renewables 2018* forecast, reaching nearly 22 GW by 2024 (Figure 1.26). Onshore wind and utility-scale PV together account for two-thirds of the increase, driven by energy auctions, followed by hydropower owing to the large number of projects in development. Argentina's challenging macroeconomic environment, limited access to affordable financing and weak grid infrastructure all pose obstacles to renewable capacity growth. The accelerated case forecast therefore assumes that projects obtain financing sooner and that the number of corporate PPAs rises quickly following the first multi-buyer signings.

Competitive auction timelines and volumes determine annual additions in the main case; accordingly, they are expected to peak in 2020 as projects from the 2016 and 2017 auction rounds come online. Growth then slows in 2023 because only 400 MW of capacity was auctioned in 2018, resulting in contracts for under 300 MW, compared with 1 GW in previous rounds. Despite grid integration challenges, Argentina announced a fourth auction round to take place at the end of 2019, which will raise annual additions towards the end of the forecast period.

Outside the auction system, large-scale solar and wind projects are expected from corporate PPA deals, a trend that is gaining popularity in Latin America. Thus far in Argentina, 10-year corporate PPAs with automotive and food production companies have been signed for an estimated 200 MW of onshore wind capacity. PPAs of a relatively short duration indicate that developers are eager to take on market risk and are able to obtain financing. In the accelerated case, the forecast assumes the timely commissioning of projects from the auction system, as well as larger volumes contracted under corporate PPAs as both corporations and developers gain more experience in hedging financing risks.

Distributed solar PV capacity is set to expand visibly towards the end of the forecast period, supported by a self-generation. Additionally, the specialised FODIS fund supports small and medium-sized PV projects with loans and capital contributions, spurring further growth.

Figure 1.26 Argentina and Chile: Renewable electricity forecast summary



Chile's renewable capacity is forecast to expand 36% to nearly 16 GW by 2024, with onshore wind increasing the most, followed by solar PV and hydropower. It is set to commission the largest (and only) CSP project in Latin America (the Cerro Dominador project), and renewable capacity expansion is also propelled by the mandate for 20% renewable electricity by 2025, the progressive phaseout of coal-fired power plants, technology-neutral energy auctions and net-metering schemes.

Table 1.11 Argentina and Chile: Drivers, challenges and accelerated case assumptions

Country	Drivers	Challenges
Argentina	Long-term renewable capacity targets; dedicated renewable energy auctions by technology; growing corporate PPA market.	Uncertainty over future auction timelines; weak grid infrastructure; challenging macroeconomic environment.
Accelerated case assumptions	Timely construction of projects that secured PPAs through previous auction rounds. Faster uptake of renewables under corporate PPAs.	
Chile	Ambitious short- and long-term renewable capacity and climate targets; energy auctions; clear permitting regulations; net-metering.	Demand-driven auction timelines make auction volumes uncertain in the short term; grid infrastructure upgrades do not keep pace with renewable project lead times; corporate PPAs are relatively new.
Accelerated case assumptions	Faster construction of CSP projects; timely construction and connection of awarded PV and wind projects; grid improvements; clarity over auction timelines.	

Chile's utility-scale renewable capacity expansion depends mostly on demand-driven auction timelines and on project commissioning schedules. Previous auctions in 2016 and 2017 awarded around 7.5 TWh of renewable projects, but the energy regulator did not hold energy auctions in 2018 or the first half of 2019. This lack of additional auction volumes therefore produces a lull in project development after 2022, pushing developers to seek revenues outside the auction system. In May 2019, Chile's first corporate PPA was signed for a 3-MW renewable project scheduled to come online in 2020 (technology and price undisclosed).

A lack of additional auction capacity, financing challenges and relatively slow grid infrastructure upgrades limit deployment. In the accelerated case, however, Chile's renewable capacity expansion is 1 GW higher with faster onshore wind uptake, solar PV projects securing financing outside of the auction system, and faster deployment of CSP.

Sub-Saharan Africa

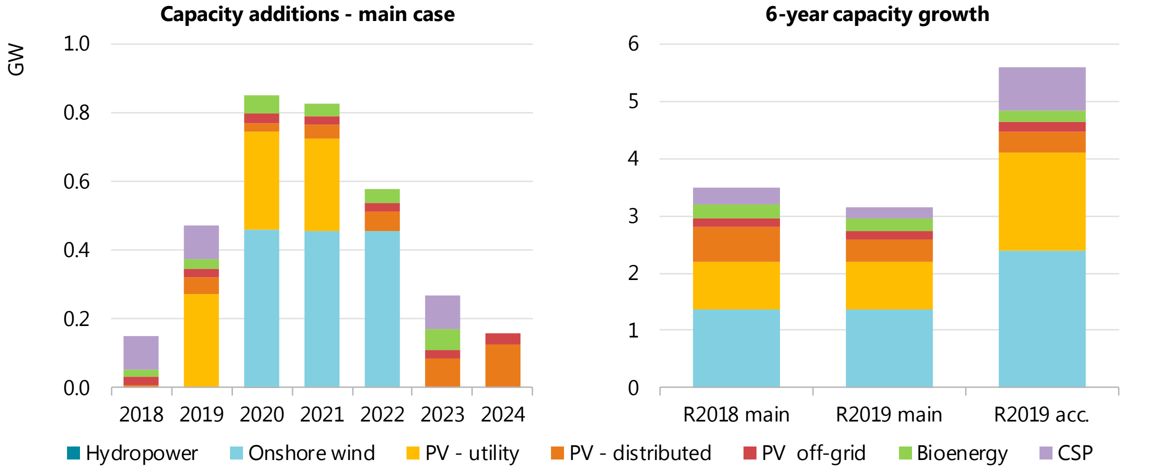
South Africa

South Africa's renewable capacity is forecast to grow 3 GW to nearly 11.5 GW by 2024. Expansion is led by utility-scale solar PV and onshore wind contracted in past auction rounds, as developers signed PPAs and reached financial closure in 2018. CSP capacity increases with the commissioning of two projects, also procured through auctions, whereas distributed solar expands as a result of net-metering availability and from on-grid customers installing PV panels for backup power during the recurrent blackouts. Nevertheless, faster growth is limited by a lack of visibility over future auction volumes and timelines, and by the off-taker's (Eskom's) financial difficulties, which raise investment risks. Should these barriers be removed, South Africa's renewable capacity growth could be almost twice as high.

Annual additions are expected to expand during 2019-22 with the commissioning of 1.4 GW of onshore wind capacity and 800 MW of large solar PV projects awarded in past auctions (rounds 3.5, 4, and 4.5) (Figure 1.27). However, a lack of progress concerning future auction rounds results in fewer annual additions in 2023-24. CSP is forecast to grow 200 MW, as the Kathu project came online in 2019 and Redstone is scheduled for 2023, both contracted under the Renewable Energy Independent Power Producer Procurement Programme (REIPPPP) auction round 3.5. If the long-planned "expedited" auction round were to be held, PV, wind and CSP capacities could expand an additional 2.5 GW in the accelerated case.

Distributed PV additions are expected to double on a y-o-y basis, triggered by net-metering and rising electricity prices, adding 400 MW of capacity. Additionally, commercial consumers invest in solar PV instead of expensive diesel-fuelled generators as backup during grid service interruptions. However, a lack of comprehensive national regulations and the potential risk of revenue loss by municipalities limit growth under net-metering. Should these barriers be addressed, greater expansion is forecast in the accelerated case.

Figure 1.27 South Africa: Renewable electricity forecast summary



Notes: Acc. = accelerated case. R2018 = *Renewables 2018* forecast for 2018-23 (IEA, 2018). R2019 = *Renewables 2019* forecast for 2019-24.

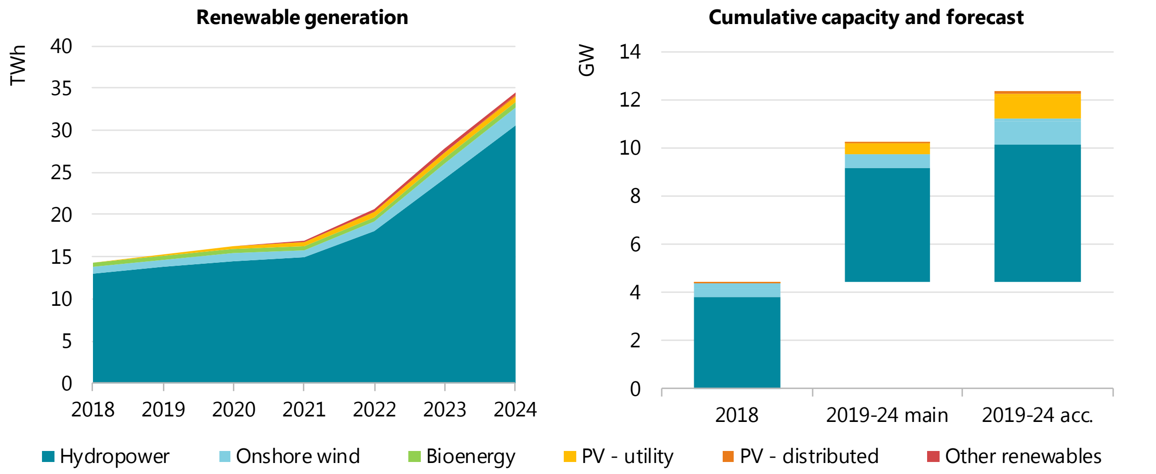
Ethiopia

In the main case, **Ethiopia**'s renewable capacity more than doubles to 10.5 GW by 2024, consistent with the *Renewables 2018* forecast (Figure 1.28). Growth continues to be heavily dominated by hydropower, followed by onshore wind and solar PV. The country's potential remains high, and renewable expansion could be 35% greater with faster construction on hydropower sites, the timely running of auction rounds and the removal of administrative barriers.

Ethiopian **hydropower** capacity is set to be 5 GW higher by 2024 with full commissioning of the Genale Dewa III project and partial commissioning of the 6-GW Grand Renaissance Dam. Strong hydropower expansion is driven by the government's ambitious strategy to become a regional electricity exporter, but achievement of these plans depends on the timely commissioning of hydropower projects, grid connections and the completion of cross-border transmission lines. The accelerated case for hydropower therefore assumes the earlier commissioning of projects already under construction.

The World Bank Group's Scaling Solar programme and nationally organised competitive auctions for PPAs stimulate growth in **utility-scale solar PV** and **onshore wind** projects. Although two rounds of the Scaling Solar programme have been opened so far, with the aim of awarding up to 900 MW of **solar** capacity, none of the auctions has reached completion. Therefore, given the long auction timelines, delays in PPA signing and prolonged project lead times, only half of these projects are expected to come online in the main case, while the rest are included in the accelerated case. **Onshore wind** additions total 550 MW as a result of Independent Power Producer (IPP) auctions, as several projects have reached financial closure. However, irregular auction rounds, delays in signing PPAs, grid connection risks and off-taker instability have resulted in higher borrowing costs, impeding faster wind expansion. Wind growth is almost one-third higher in the accelerated case, which assumes that risk-mitigation measures address these challenges in the short term. Ethiopia's **off-grid PV** expansion leads distributed PV growth, with mini-grids and solar home systems adding 70 MW of capacity over the forecast period, motivated by the goal of universal electrification.

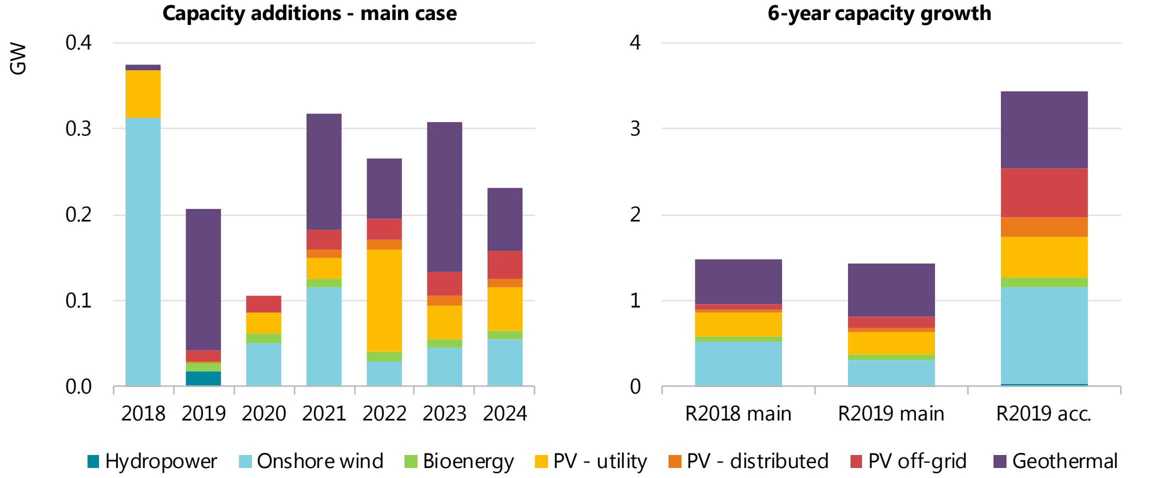
Figure 1.28 Ethiopia: Renewable electricity forecast summary



Kenya

Kenya's renewable capacity is set to expand by 70% (1.4 GW), with geothermal accounting for nearly half of all renewable additions, followed by solar PV and wind (Figure 1.29). Annual additions are guided by the commissioning timelines for geothermal and utility-scale PV projects, and untapped resource potential, high FIT levels, long-term PPAs and electrification are the main drivers behind the growth. However, policy uncertainty, persistent land acquisition issues, poor off-taker financial health and grid connection delays limit expansion. Kenya's renewable capacity growth is twice as high in the accelerated case, provided that the government assures long-term policy framework certainty, ensures timely PPA signing and removes administrative barriers.

Figure 1.29 Kenya: Renewable electricity forecast summary



Notes: Acc. = accelerated case. R2018 = Renewables 2018 forecast for 2018-23. R2019 = Renewables 2019 forecast for 2019-24.

Geothermal capacity doubles over the forecast period with the commissioning of projects currently in various stages of development – a 100-MW upward revision from last year, owing to the completion of pre-feasibility studies that indicate higher output potential. Not only could geothermal growth reduce electricity tariffs as well as dependency on imported diesel for electricity generation, it could raise the level of electrification in the country. In 2019, Kenya's installed geothermal capacity is set to overtake Iceland's with commissioning of the Olkaria V project. However, financing challenges make the pace of project development a forecast uncertainty, so geothermal expansion is one-third higher in the accelerated case if large-scale projects reach financial closure more quickly.

Utility-scale PV and wind capacities are expected to more than double over 2019-24, encouraged by Kenya's FIT scheme and long-term PPAs. The forecast has been revised upwards because some wind projects are finally reaching financial closure two years after the PPAs were signed. However, long project lead times, policy uncertainty concerning PPAs, administrative barriers, weak grid infrastructure and off-taker unreliability hamper faster growth. In the accelerated case forecast, Kenya's PV and wind growth could be threefold higher if the government addressed these challenges. **Off-grid PV** is estimated to account for one-fourth of total solar expansion, driven by electrification goals and supported by World Bank financing.

Table 1.12 Sub-Saharan Africa: Drivers, challenges and accelerated case assumptions

Country	Drivers	Challenges
South Africa	Supportive policy environment with long-term PPAs and rising electricity prices.	Irregularly organised auction rounds; PPA signing delays; weak off-taker financial health; slow pace of grid extension.
Accelerated case assumptions	Certainty over future auction volumes and timelines, paired with an improvement of Eskom's financial situation.	

Country	Drivers	Challenges
Ethiopia	Clear national strategy to become regional electricity exporter; national and Scaling Solar auctions.	Delays in PPA signing; irregularly organised IPP auction rounds; delays in Scaling Solar auction processes; slow grid expansion.
Accelerated case assumptions	Completion of Scaling Solar and the IPP auction rounds, with all planned projects obtaining financing. Timely project construction paired with grid connection.	
Kenya	Availability of FITs with long-term PPAs; concessional financing options; 2021 universal electrification target; abundant renewable resources.	Uncertainty over future policy support; difficulty reaching financial closure; land acquisition issues; grid connection delays.
Accelerated case assumptions	Certainty over future policy support; timely PPA signing; assurance of timely grid connection; shielding of investors against potential losses; removal of administrative barriers.	

Other sub-Saharan Africa countries

The rest of the region is forecast to add 11.6 GW of capacity during 2019-24, with hydropower accounting for nearly half of the expansion, followed by solar PV and wind. Hydropower deployment is stimulated by nationally developed and financed projects, while PV and wind expansion are driven by national FIT policies, Scaling Solar auctions, national tenders, and off-grid PV expansion supported by concessional financing. Hydropower growth in the rest of the region is spread across several countries, but **Angola** leads with the 1-GW Lauca dam and the smaller Chicapa II project to come online by 2024, and **Nigeria** is developing several projects, including the 700-MW Zungeru dam.

Countries in the region are increasingly using auction programmes to procure new utility-scale PV capacity, usually with the support of international financing institutions. **Senegal** and **Zambia** recently concluded their first solar PV auctions with support from the World Bank's Scaling Solar programme. **Senegal**'s auction resulted in a price of USD 47/MWh for a 60-MW solar PV project, while **Zambia** awarded 120 MW of solar PV capacity to four developers at USD 60/MWh. **Madagascar** and **Gambia** recently opened their first solar PV auctions; **Tanzania** issued a request to qualify for 150 MW of solar PV capacity; and **Togo** just joined the Scaling Solar programme. All projects are expected to be commissioned within the forecast period.

Middle East and North Africa

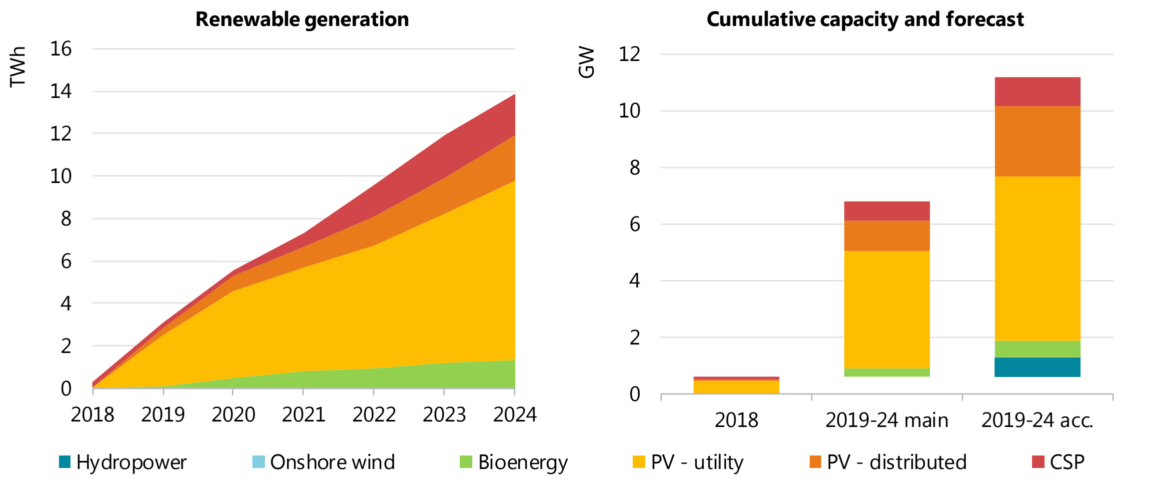
United Arab Emirates

Renewable capacity of the **United Arab Emirates** is expected to increase tenfold (+6.3 GW), almost entirely from solar PV and CSP owing to strong policy support (Figure 1.30). Overall, the country targets 44% renewable electricity by 2050, with a majority of policy support in the form of competitive auctions and net-metering. Strong drivers for growth continue to be the country's excellent solar resources, rising power demand and the need to rely less on natural gas.

The forecast has been revised up significantly from *Renewables 2018*, mostly because of the announcement of new solar PV auctions. Last year, four emirates (Dubai, Abu Dhabi, Umm Al Quwain and Ras Al Khaimah) announced plans to collectively develop 3.7 GW of new utility-scale PV through upcoming competitive IPP auctions and engineering, procurement and construction (EPC) contracts. In addition, an extra 250 MW of planned PV capacity was awarded in Dubai's latest competitive tender (originally meant for CSP bids only) as part of a hybrid PV-CSP offer. These developments result in significantly more utility PV over 2019-24 than was foreseen in *Renewables 2018*, while the forecast for CSP remains in line with last year's expectations. While the new announcements signal rapid progress towards the country's targets, a lack of longer-term visibility over auction timelines challenges faster growth. Combined utility-scale PV and CSP expansion could be one third higher if the pace of auctions and project development accelerates.

Higher growth is also expected in distributed PV, mostly from commercial and industrial systems under Dubai's net-metering scheme after several third-party developers announced an increase in contracted customers. The forecast for the residential segment has also been revised up slightly to reflect the government's latest target to equip 10% of all homes with rooftop PV. However, low electricity prices for some customers limits the economic attractiveness of net-metering and hampers both household and commercial growth. Should retail prices become cost-reflective, distributed PV capacity would expand twice as much in the accelerated case, which already takes into account distributed PV growth in Ras al Khaima owing to the government's plans to develop 600 MW of rooftop PV in early 2019. The accelerated case also demonstrates faster bioenergy growth with the realisation of waste-to-energy plants and deployment from a planned PSH project.

Figure 1.30 United Arab Emirates: Renewable electricity forecast summary



Notes: Acc. = accelerated case.

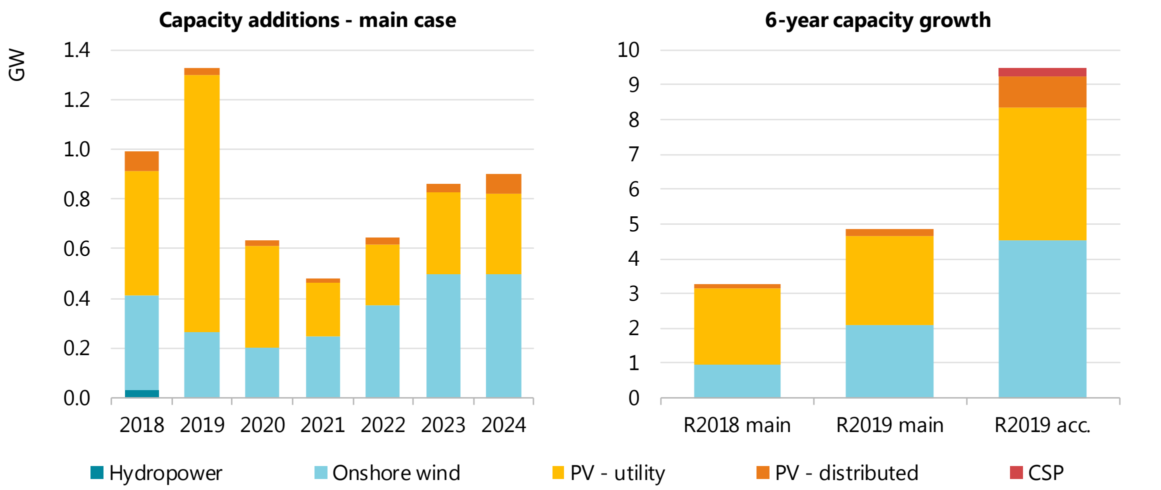
Egypt

Egypt's renewable capacity doubles over 2019-24, entirely from solar PV and onshore wind, driven by rising electricity demand and targets for 20% renewable generation by 2022 (Figure 1.31). Annual growth is expected to peak in 2019 as the commissioning deadline is met for the 1.8 GW of solar PV projects developed under the discontinued FIT scheme. Annual additions after 2019 will be guided by project development under the various other procurement schemes, the pace of which is a key forecast uncertainty. Over 3 GW are under development through state-owned projects, bilateral contracts and competitive auctions, but long lead times due to complex administrative processes and policy uncertainty over deadlines challenge the speed of deployment. Renewable capacity growth could be 96% higher with improved procurement process transparency, simplified permitting procedures and faster auction implementation.

Overall, the forecast has been revised up by almost 50% owing to an increasing number of utility-scale **wind** and **solar PV** projects emerging from bilateral contracts as delays in competitive auction schemes drive developers to seek other opportunities. Roughly 500 MW of wind projects from competitive auctions have stalled over tariff negotiations and 800 MW of solar PV tenders have been subject to various delays and deadline extensions. Long implementation processes, changing auction rules and deadlines, and the lack of a future auction schedule are the main challenges to expansion under the auction scheme. This has caused many developers to approach the state utility and large industrial consumers to negotiate PPAs directly. For solar PV in particular, the increase to 20 MW for net-metering eligibility is making it economically attractive for utility-scale projects to enter into corporate PPAs under third-party business models with large consumers.

Distributed solar PV capacity doubles, mostly from commercial-sized systems as self-consumption becomes increasingly economically attractive. Net-metering, falling system costs and rising electricity prices due to subsidy discontinuation are the main drivers for growth. However, slower growth is forecast for the residential segment under net-metering because the price differential between system costs and electricity prices is not yet advantageous for self-consumption. A lack of affordable financing and limited rooftop space on multi-family buildings also challenge deployment.

Figure 1.31 Egypt: Renewable electricity forecast summary



Notes: Acc. = accelerated case. R2018 = *Renewables 2018* forecast for 2018-23 (IEA, 2018). R2019 = *Renewables 2019* forecast for 2019-24.

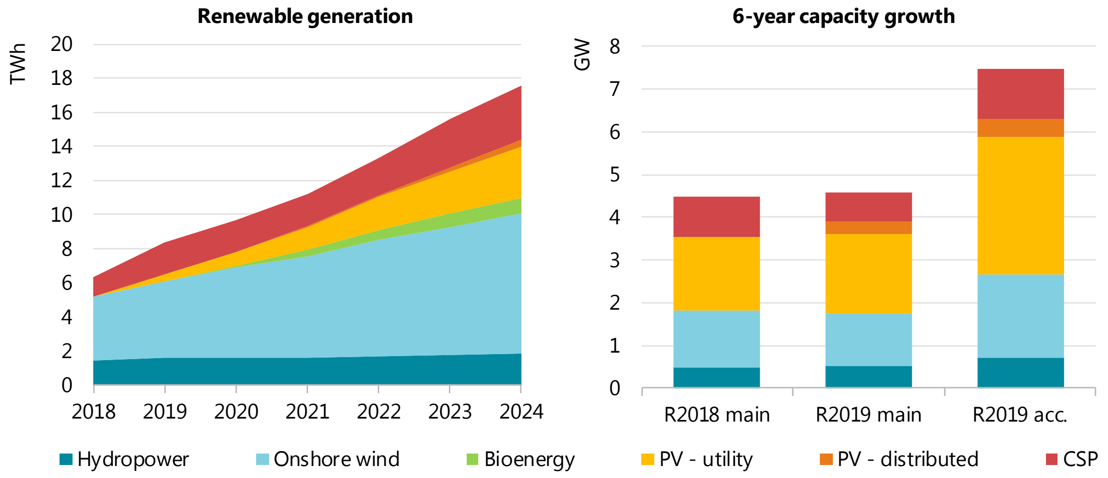
Morocco

Morocco's renewable capacity is expected to more than double with growth led by solar PV, onshore wind, hydropower and CSP owing to the country's supportive policy environment (Figure 1.32). Long-term targets for renewable generation and a successful track record of timely competitive auctions and concessional financing are the main drivers of growth. Outside of auctions, expansion is expected to result from state-owned projects and bilateral contracts with either the state-owned utility or large consumers. Growth could be 65%

greater if auctions continue to be held more frequently and progress under the various other schemes accelerates. Challenges to faster growth include limited access for new market entrants.

Overall, the forecast has been revised up slightly to reflect the increasing economic attractiveness of solar PV and CSP, a faster auction pace and a more optimistic forecast for distributed PV. The tender for Noor I Midelt, the latest hybrid CSP-PV tender (800 MW), resulted in a price of USD 63.5/MWh (USD 70/MWh for peak production) – lower than the USD 74/MWh for CSP alone in Dubai. Just after these results were announced, another hybrid CSP-PV auction for 230 MW (190 MW peak production) was opened in July 2019, signalling the economic attractiveness of the previous hybrid auction approach. This latest auction was not foreseen last year and is one of the main reasons for this year's upward revision for solar PV.

Figure 1.32 Morocco: Renewable electricity forecast summary



Notes: Acc. = accelerated case. R2018 = *Renewables 2018* forecast for 2018-23 (IEA, 2018). R2019 = *Renewables 2019* forecast for 2019-24.

Distributed solar PV deployment is led by the commercial segment and is based on the expectation that grid connection will be possible during the forecast period. While access was granted to the distribution network by a decree in 2015, the regulation to implement it has been slow to materialise due to system integration concerns. This year, a consultation among stakeholders was launched to provide recommendations on how to address the technical and financial barriers and move the regulation forward. This progress, which increases the likelihood of a future net-metering scheme, the good match between demand and solar irradiation, and falling system costs, are the impetus for strong commercial PV growth in the forecast.

Hydropower capacity is estimated to expand 30% from a 350-MW state-owned pumped storage project and several smaller, privately owned projects under 50 MW.

Table 1.13 MENA: Drivers, challenges and accelerated case assumptions

Country	Drivers	Challenges
United Arab Emirates	Supportive policy environment with competitive auctions for long-term PPAs; rising electricity demand; net-metering.	Lack of auction schedule; barriers to new market entrants; low retail electricity prices.
Accelerated case assumptions	Certainty of future auction volumes; higher electricity prices; progress in developing waste-to-energy and pumped hydropower plants.	
Egypt	Several procurement processes; good resource potential; net-metering; rising electricity prices.	Lack of a transparent procurement process; PPA signing delays; irregularly organised IPP auction rounds; lack of access to affordable financing.
Accelerated case assumptions	Simplified permitting processes; improved transparency in procurement processes; faster auction implementation.	
Morocco	Clear long-term targets supported by transparent and timely competitive auctions; affordable financing; good resource potential, net-metering.	Uncertainty over the timeline for future auctions; limited access for new market entrants.
Accelerated case assumptions	Faster auction implementation; rapid takeoff of distributed PV in the commercial and residential sectors; more private sector investment resulting from improved economic attractiveness of corporate PPAs with industrial consumers on the distributed grid.	

Other MENA countries

Saudi Arabia's renewable capacity is expected to reach almost 3 GW by 2024, a substantial ramp-up from the currently low base of less than 200 MW. Almost all growth results from competitive auctions for solar PV and onshore wind. This year's forecast has been revised up 30% because new auctions were announced after renewable energy targets were raised. Most of the revised expansion is in solar PV, as targets are now three times higher for 2023 and new plans to tender 2.2 GW were released in 2019. Unprecedentedly swift progress has been made since then, with 1.5 GW already at the pre-development stage and close to opening. Other strong growth stimulants are the economic attractiveness of solar PV and wind, which have recently been contracted at regional record-low prices of USD 23.6/MWh (solar PV) and USD 21.3/MWh (wind), likely because of low land costs. The speed of overall deployment depends on the pace of auctions, however, which tends to be slower than planned. As a result, the main case forecast is conservative compared with the accelerated case, which forecasts almost seven times greater expansion, assuming the pace of auctions continues to accelerate.

Renewable capacity in **Iran** is forecast to expand 14% (1.8 GW), led by solar PV, hydropower and onshore wind. Growth from variable renewables is expected to outpace hydropower over the forecast period as a result of slow development of planned pumped storage hydropower projects and an increase in the number of wind and solar PV projects applying for the country's generous FITs. Whether all these wind and solar PV projects will be realised is a forecast uncertainty, however, due to the difficult financing conditions resulting from imposed trade restrictions. In addition, distributed solar PV growth continues to be limited by a lack of consumer awareness despite attractive remuneration. The accelerated case for Iran's renewable capacity demonstrates three times as much growth as the main case with improved financing conditions.

Jordan's renewable capacity doubles (1.4 GW) over 2019-24, with onshore wind and solar PV expanding the most as a result of competitive auctions, state-owned projects and net-metering. The forecast has been revised down slightly due to a reduction in tendered capacity in the latest round of auctions and a halt on permitting for new projects over 1 MW. Both developments likely result from the grid constraints that have been challenging renewable capacity growth in Jordan for the past several years. The halt on permits is expected to affect large consumers using net-metering to enter into third-party business arrangements or corporate PPAs, mainly distributed PV installations of more than 1 MW in mosques, universities and public buildings. Overall growth is almost twice as high in the accelerated case with network expansions and upgrades allowing the grid to integrate more renewable capacity.

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2. Distributed solar PV

Highlights

- **In 2018, distributed solar photovoltaic (PV) additions reached a record 41 gigawatts** (GW), accounting for more than 40% of total PV and one-quarter of all renewable capacity growth. With this expansion, global distributed PV capacity (led by commercial/industrial applications) reached 213 GW.
- **Europe has the largest distributed PV capacity worldwide**, accounting for almost 40% of all commercial and residential systems operating in 2018, followed by the Asia-Pacific region, the People's Republic of China ("China") and North America, all having strong policy incentives in place. Deployment outside these regions has remained limited due to the absence of policies and regulatory schemes.
- As a result of rapid cost reductions in the past decade, the levelised generation costs of commercial and residential systems are below variable retail electricity prices in most countries – except those where electricity is subsidised. Residential and commercial PV investment costs are expected to drop a further 15-35% over the forecast period (2019-24), raising economic attractiveness and adoption worldwide.
- **Policy remains the key growth stimulant.** Although remuneration for all distributed PV generation (through buy-all, sell-all programmes) and annual net metering with retail pricing have been the main policies incentivising distributed PV, countries are slowly switching to shorter net-metering accounting periods and value-based remuneration of PV generation fed into the grid, usually with tariffs below retail prices to avoid overcompensation and contain utility revenue losses.
- **Distributed solar PV capacity grows by over 317 GW to reach 530 GW by 2024**, a similar expansion to onshore wind. Commercial and industrial solar PV, with a capacity of 377 GW in 2024, is expected to account for over 70% of the growth. China remains the largest growth market, and expansion in the Asia-Pacific region surpasses that of Europe and North America because India, Japan and Korea have strong policy incentives. In the European Union, commercial PV growth accelerates in Germany as well as other countries as costs continue to fall and the policy environment improves.
- **Residential solar PV capacity is expected to increase from 58 GW in 2018 to 143 GW in 2024**, owing mainly to rapid expansion in China as a result of a specific budget subsidy offered under a buy-all, sell-all model. The United States continues to demonstrate the second-largest growth, led by California, and Australia and Japan lead Asia-Pacific deployment while growth remains limited in India. In Europe, expansion is concentrated in the Netherlands, Germany, Italy, Belgium, France and Spain, which together account for two-thirds of the region's deployment over the forecast period.
- **Global off-grid capacity doubles to over 10 GW in 2024**, led by developing Asia and followed by sub-Saharan Africa. Commercial segments such as stand-alone irrigation pumps expand the most, followed by mini-grids and solar home systems (SHSs). By 2024, almost 80 million more people are expected to have access to electricity services through SHSs.
- Under current retail tariff structures, cumulative global transmission and distribution (T&D) revenue losses over 2019-24 could amount to USD 70 billion – equivalent to almost one-quarter of all T&D investment worldwide in 2018. Sustainable distributed PV deployment will depend on appropriate market design as well as tariff and policy frameworks that balance the competing interests of PV owners, distribution companies and other consumers.

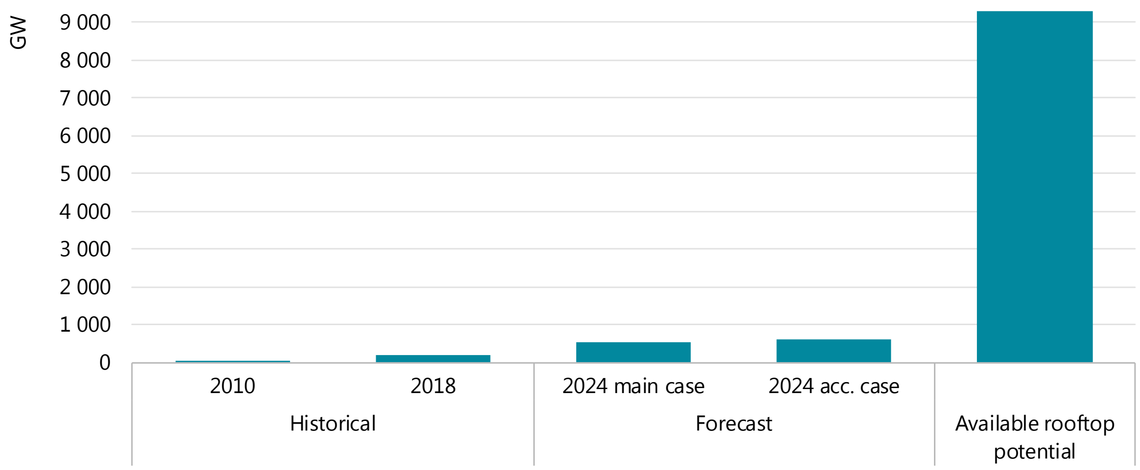
Why focus on distributed solar PV?

Propelled by strong policy support concentrated mostly in Europe, the United States and Japan, distributed solar PV deployment has been growing exponentially. Rapid investment cost reductions of 60-80% since 2010 have raised the economic attractiveness of solar PV, facilitating the adoption of residential and commercial applications. Furthermore, the levelised cost of energy (LCOE) of distributed solar PV is lower than variable retail electricity prices in many countries where electricity prices are not subsidised. In 2018, distributed PV additions accounted for 40% of total PV growth worldwide and exceeded the net capacity additions of coal and nuclear combined.

Ongoing policy incentives and cost reductions in the next five years are expected to further improve the distributed PV business case, expanding its adoption by residential and commercial consumers. Global distributed solar PV capacity, including off-grid applications, is expected to almost triple – even reaching over 600 GW by 2024 in the accelerated case (Figure 2.1). In fact, of all renewable technologies, residential and commercial PV applications demonstrate the most potential for additional expansion in the accelerated case, assuming rapid consumer adoption under favourable economic, policy and regulatory conditions.

Even in the accelerated case forecast, however, global installed capacity in 2024 represents only 6% of technical potential based on available rooftop area. Increasingly affordable and economically attractive distributed PV systems for hundreds of millions (or even billions) of private investors could therefore lead to a distributed PV expansion boom in upcoming decades.

Figure 2.1 Global distributed solar PV historical capacity, forecast and technical potential



Note: Available rooftop potential is calculated based on IEA (2016), *Energy Technology Perspectives 2016*.

Additional private capital investments on a USD-trillion scale would be highly welcome in light of the current need to accelerate investment in clean energies to achieve long-term sustainability goals. However, the implications of unmanaged distributed PV growth could be disruptive for electricity markets as they affect system costs, the grid integration of renewables, distribution company revenues and retail electricity prices.

Integrating distributed PV energy into the grid is more challenging when the timing of solar PV production does not correspond closely with customers' electricity consumption. This is particularly the case for residential PV in temperate climates, where peak demand in the winter occurs in the evening and peak PV output in the summer is at midday. Furthermore, this challenge can be compounded by certain incentive schemes, such as annual net metering, that do not take account of this mismatch. Coupling distributed PV with small-scale storage can help, though, if the economics permit it. The problem is less severe in warmer countries, where both air conditioning and commercial load profiles are much better aligned with peak solar output, leading to a more advantageous supply-demand match and thus higher shares of self-consumption.

Policy makers will need to address these and other issues through tariff reforms, integrated resource planning and other policies that take better account of the actual value distributed PV brings to the whole system, not just to private-consumer investors. Although a detailed policy analysis is outside the scope of this market report, it will be the object of other IEA studies and policy notes in 2020.

The five sections of this chapter examine the drivers of and challenges to distributed PV expansion, both historically and in the next five years:

1) **Distributed PV today** presents the evolution of distributed solar PV deployment since the early 2000s and background material on system cost reductions by country.

2) **Distributed PV policies** categorises the policy incentives offered by various countries and discusses their impact on economic attractiveness.

3) **Economics of distributed PV** explains investment and generation cost developments during the forecast period, as well as remuneration schemes for excess generation in several countries. This section also examines financing trends and funding models in key markets.

4) **Distributed PV forecast** presents the drivers behind the distributed PV forecast and challenges to anticipated residential, commercial and off-grid expansion.

5) **Policy-making implications** discusses the impacts of forecast deployment on consumers, distribution companies and governments, with a focus on retail pricing design and how it affects revenue losses for various stakeholders.

Distributed PV history and the situation today

In 1958, the United States became the first country to use satellite solar PV, on NASA's Vanguard satellite. It had six silicon solar cells with a total 1-watt (W) capacity that powered the satellite's second transmitter reliably for six years. In the 1960s, solar cells were used mostly on satellites and spacecraft, but after the oil crisis in 1973, more research and development (R&D) funds were directed towards improving solar cell efficiency and reducing their costs for commercialisation, mainly in the United States and Japan. Initial solar PV applications outside the space industry were mainly for off-grid telecom or small rooftop systems in the 1980s, due to their relatively high cost and modularity. With higher sustained investments in manufacturing and R&D, the cost of solar cells dropped from USD 32/W in 1980 to USD 9/W in 1990 when global PV capacity, mostly off-grid, reached more than 320 megawatts (MW) (excluding solar cells used in small appliances such as calculators).

Box 2.1. Defining distributed solar PV

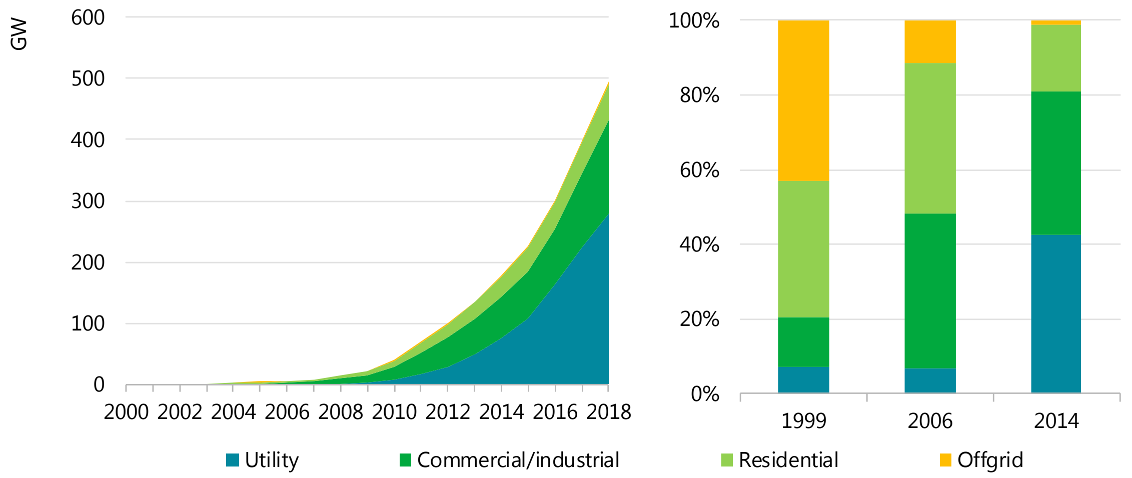
Renewables 2019 divides distributed PV into three main categories: 1) residential; 2) commercial and industrial; and 3) off-grid applications. These groupings take not only size into account (see table below), but the purpose of the installation and the availability of data. For residential applications, categorisation is usually easy and does not vary significantly across countries, but for commercial and industrial applications, data unavailability and the purpose of the installation make classification more challenging. For instance, even though *Renewables 2019* accepts China's National Energy Administration (NEA) definition of distributed generation, some commercial and industrial systems in China are known to be larger than 1 000 kilowatts (kW). The situation is similar in some Middle East and North Africa (MENA) countries, where ground-mounted installations of more than 1 000 kW provide electricity to nearby industries, but this report also categorises them as commercial/industrial applications because of their self-consumption purpose. Furthermore, data availability is limited for some countries, so *Renewables 2019* approximates the category based on data from similar markets.

Distributed PV categorisation by size

Segment	Size	Explanation
Residential	0-10 kW	Rooftop systems connected to the grid
Commercial and industrial	10 kW-1 000 kW	Rooftop and ground-mounted systems connected to the grid
Off-grid	8 W-100 kW	SHSs, small commercial installations and mini-grids

Because PV was not initially cost-competitive with large utility-scale power plants, early deployment was at the distributed level for relatively small residential, commercial and off-grid applications. As costs dropped, however, PV installations became larger, with market segmentation marked by three key inflection points. Until 1999, off-grid systems for telecom relays, water pumping and electrification in remote areas (such as islands) made up the largest PV segment (Figure 2.2). Behind-the-meter (BTM) residential systems supported by feed-in tariffs (FITs) then became popular and remained the largest application until 2005-06 owing to administratively set tariffs in Europe and state-level incentives in the United States. Most recently, expanding policy support in some EU member countries has prompted commercial and industrial PV capacity to increase from just over 2.5 GW in 2006 to 68 GW in 2014 – and since 2015, global distributed PV capacity (led by commercial/industrial and residential applications) has almost doubled (to 213 GW in 2018), accounting for over 40% of total cumulative PV installations.

Figure 2.2 Cumulative solar PV capacity by application segment



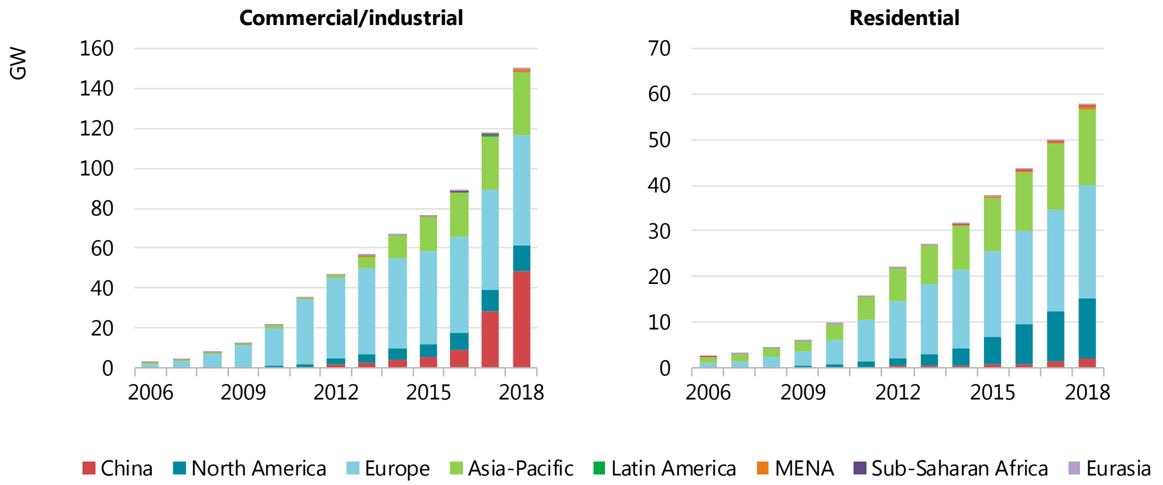
Europe has the most distributed PV capacity worldwide, accounting for almost 40% of all global commercial/industrial and residential systems operating in 2018, followed by the Asia-Pacific region, China and North America (Figure 2.3). Deployment outside these regions remains limited by a lack of not only policies and regulatory schemes, but economic attractiveness.

For commercial applications, Europe accounts for almost one-third of global installed capacity, with most expansion resulting from generous incentive schemes in Germany, Italy, Spain and Belgium, especially from 2006 to 2012. FITs for 20 years (mostly through buy-all, sell-all models) ranged from EUR 400 per megawatt hour (/MWh) to EUR 500/MWh in 2006-07, then declined to EUR 200/MWh to EUR 250/MWh in 2011-12. Despite this rapid reduction, developers installed record levels of commercial projects because tariffs were significantly higher than generation costs, leading to windfall profits in some countries.

The boom in distributed PV deployment raised questions over the effectiveness of administratively set incentive schemes, however, and their costs to governments and consumers. As a result, Spain, Italy and the Czech Republic retroactively changed support schemes, and Germany, France and Belgium reduced tariff levels significantly, leading to bust-deployment cycles.

Generous incentive schemes were not limited to Europe. In China, high tariffs for commercial/industrial PV introduced in late 2015 boosted growth, especially for large-scale ground-mounted installations next to industrial sites. In the Asia-Pacific region, Japan's, generous FIT scheme has caused commercial solar PV capacity to increase fivefold since its introduction in 2013.

Figure 2.3 Commercial/industrial and residential solar PV capacity by country/region



For residential PV, Europe, North America and the Asia-Pacific region together accounted for 95% of global installed capacity in 2018. As with commercial installations, Europe leads global residential capacity thanks to high-level incentives, which have been significantly reduced since their introduction. Germany, Italy, the United Kingdom, Belgium and the Netherlands have the largest installed residential PV capacity in Europe. The majority of residential PV in the Asia-Pacific region is currently in Japan, owing to the country's generous FIT scheme. Australia's federal rebate scheme, which covered 30-35% of system costs in 2018 through small-scale technology certificates and state-level incentives, makes it the second-largest Asia-Pacific residential PV market. In the United States, federal tax incentives, state-level rebate programmes and annual net metering schemes have stimulated growth. California alone accounts for around half of all US residential PV installed, owing to its various subsidy programmes since 2007 as well as net metering. In contrast, China has a relatively small share of this market (Table 2.1).

Table 2.1. Top five countries for total distributed PV capacity by segment in 2018

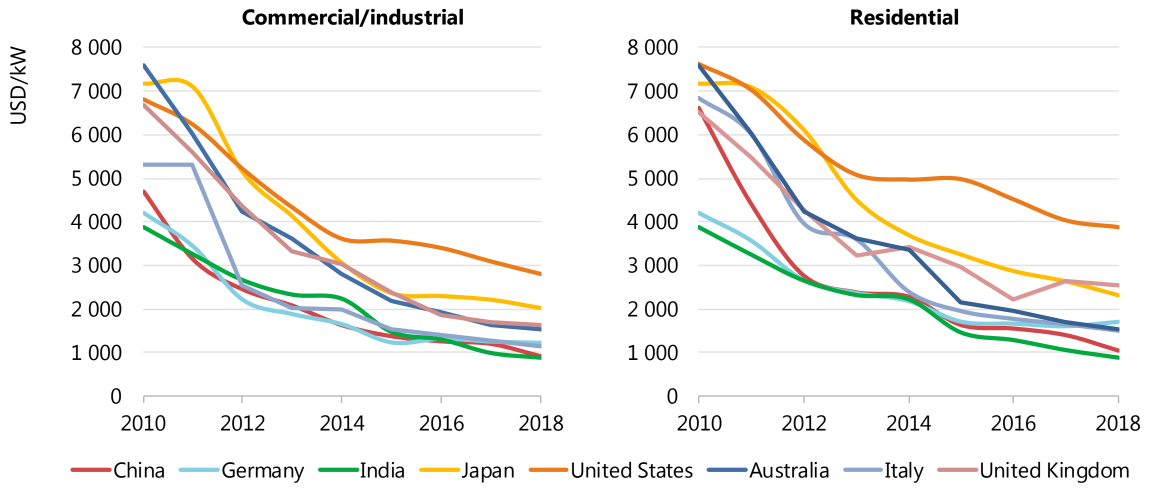
Distributed PV total		Commercial and industrial		Residential		
Country	Capacity	Country	Capacity	Country	Capacity	Top 5 per capita
China	51 GW	China	49 GW	United States	13.0 GW	Australia
Japan	34 GW	Germany	26 GW	Japan	9.0 GW	Belgium
Germany	33 GW	Japan	25 GW	Germany	6.5 GW	Austria
United States	26 GW	United States	12 GW	Australia	6.5 GW	Malta
Italy	16 GW	Italy	12 GW	Italy	4.2 GW	Netherlands

Investment cost evolution of distributed PV

The rapid decline in distributed PV investment costs has been a key deployment factor, especially in countries where generous incentives have been provided. Over 2010-18, investment costs for commercial/industrial and residential systems dropped 60-80%, depending on the country (Figure 2.4). During the same period, the decline in PV module costs accounted for roughly 70% of overall system cost reductions in China, Germany, India and Italy, and 40-50% in Japan, Australia and the United Kingdom.

However, market maturity may not translate directly into lower costs. Although the United States and Japan are among the largest distributed PV markets in the world, their PV system costs are two to three times above global benchmark prices. Incentives targeting investment costs – such as tax credits, grants and rebates – usually result in relatively higher system prices, such as in Australia and the United States. In addition, generous tariffs (such as in Japan) may lead to PV supply chain inefficiency and to equipment and service pricing based on windfall profits.

Figure 2.4 Investment costs for commercial/industrial and residential systems in selected countries



Source: IRENA (2019), *Renewable Cost Database*.

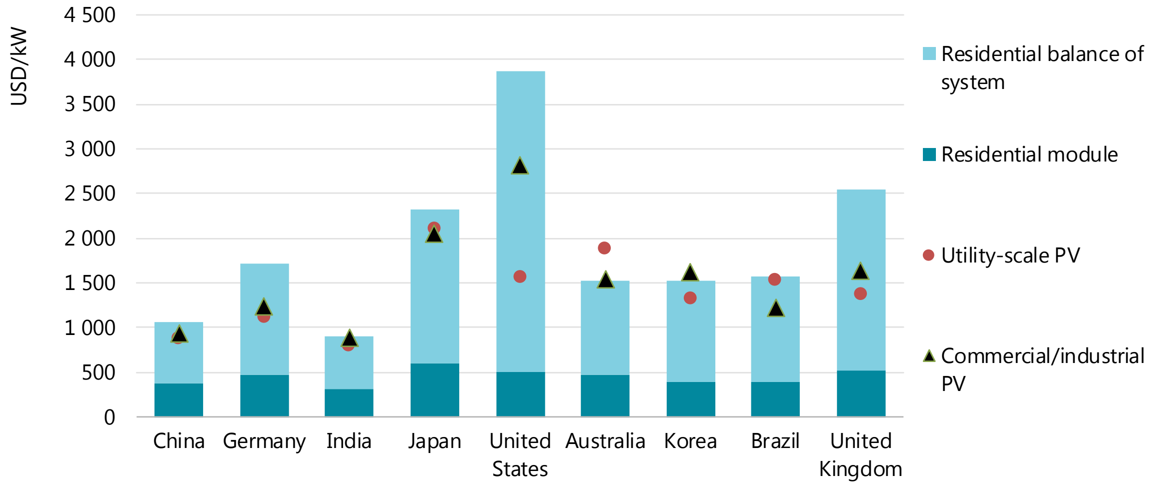
Commercial/industrial systems are on average 15-20% less costly than residential ones because of their larger size; however, larger projects may have lengthier permitting and grid connection approval processes in some countries. In Australia, commercial and utility-scale systems have been more expensive than small residential ones because of the maturity of the respective market segments, although this trend is expected to change soon with the rapid deployment of larger utility-scale and commercial/industrial applications.

Overall, utility-scale solar PV investment costs are 10-50% lower than for residential and commercial/industrial systems, depending partly on the average size of a utility-scale plant. The United States records the greatest cost gap because utility-scale projects are much larger than in other countries, compared with distributed PV applications.

Both module and balance-of-system (BoS) costs are central to system cost variations among countries today (Figure 2.5). Benchmark module costs for residential systems are estimated to range from USD 350/kW in India to USD 600/kW in Japan, but both much lower and higher values exist in all countries, depending on application size. Modules account for only 15-35% of overall residential and commercial system costs, with BoS costs representing most of the rest.

BoS costs vary significantly by country: the United States has the highest, mainly due to relatively elevated soft (i.e. non-equipment) costs, especially for customer acquisitions, labour and financing. In Japan, high security standards (because of natural disasters) raise mechanical and electrical installation prices, resulting in higher BoS costs. India, China and Germany have some of the lowest distributed PV investment costs worldwide, thanks to optimised BoS costs in Germany and China, and low module prices and inexpensive labour in India.

Figure 2.5 Module and balance-of-system portions of total investment costs for residential PV, 2018



Source: Adapted from IRENA (2019), *Renewable Cost Database*.

Distributed PV policy schemes

Government policies, incentives and regulations have been central to distributed solar PV deployment worldwide. Many countries have introduced long-term targets for renewable energy technologies in the electricity sector that usually include all solar PV applications (Table 2.2), but China, India and several US states, among others, have introduced targets and plans specific to distributed PV.

Table 2.2. Distributed PV targets and plans

Country/state	Target	Explanation
China	60 GW	13th Five-Year Plan's target for 2020
India	40 GW	All rooftop PV by March 2022, with state-level annual trajectories
USA – Maine	400 MW	400 MW distributed generation
USA – New York	6 GW	6 GW of distributed PV by 2025
United States	% of Renewable Portfolio Standard (RPS)	Distributed generation carve-outs as percentage of state RPS programmes in 14 US states, ranging from 0.1% to 3.5% of total electricity.
United Arab Emirates – Dubai	10% of all homes	10% of all homes with rooftop PV by 2020

Distributed PV targets do not necessarily translate into deployment, as policies and regulations are usually needed to attract investment. Indeed, most countries in the world do not have distributed PV targets, but they do have targeted policy schemes or regulations. Today, distributed PV support policies are usually aimed at two main areas:

1) **Policies targeting investment costs:** These support policies usually take the form of direct financial incentives that aim to reduce investment costs and make distributed PV systems more affordable for consumers (Table 2.3). These generally include:

   a. **Grants and rebates**: a fixed subsidy, usually with a one-time payment.

   b. **Tax credits**: amounts that taxpayers can subtract from taxes, usually based on a percentage of total solar PV system investments.

   c. **Accelerated depreciation**: PV owners can receive higher tax benefits by depreciating assets more quickly, usually in the first or second year.

   d. **Tax exemptions**: sales tax or value-added tax (VAT) reduction or exemption from the PV system price.

Table 2.3. Policies targeting investment costs for distributed PV in selected countries

Country	Policy	Impact on deployment
Australia	Rebate scheme based on small renewable certificates	High
United States	30% federal investment tax credit	High
China	State-level grants and low financing rates for industrial applications	Medium
India	Residential and public sector: 30% capital grant. Commercial: 40% accelerated depreciation. Several tax exemptions for PV systems	Med/High
Brazil	VAT (20%) exemption for small systems	High
France	Self-consumption project rebates of EUR 190/kW to EUR 390/kW, depending on installation size	Med/High

2) **Policies targeting consumption and sale of electricity:**

   a. **Buy-all, sell-all:** All PV generation is deemed to be sold to the utility, usually at a fixed price (e.g. France uses commercial solar PV tenders with power purchase agreements [PPAs]; China and Japan have FIT schemes for systems larger than 10 kW). The remuneration of PV electricity can be above, equal to or lower than the retail rate, while PV owners buy all electricity at the retail price to cover their demand. In this model, PV owners are like small power plants generating electricity under a long-term PPA.

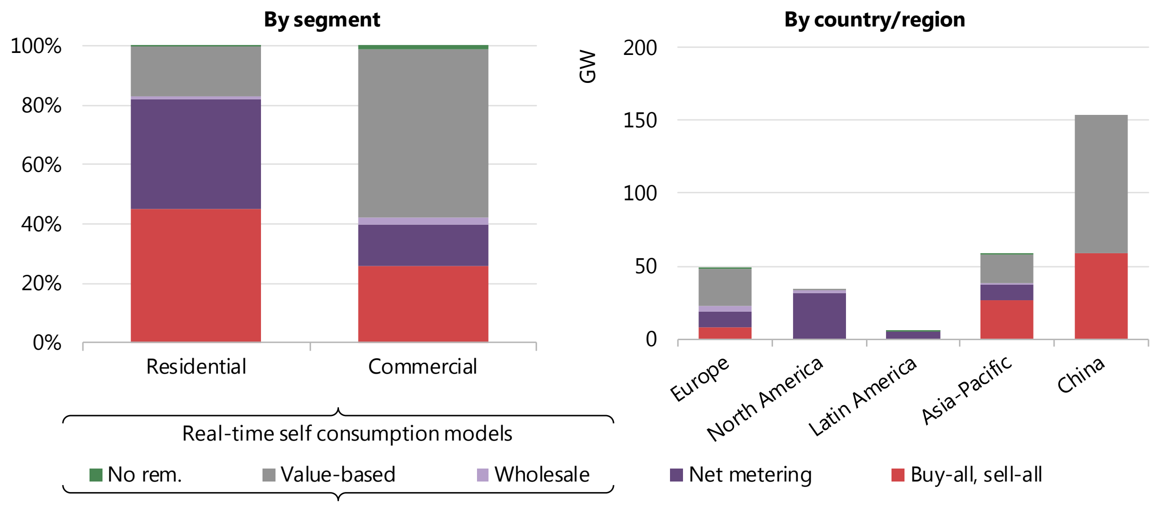
   b. **Net metering:** PV owners can self-consume the electricity they generate, which reduces their consumption from the network. In a net-metering scheme, a PV owner receives an energy credit for any excess generation exported to the network during a specific time period. This energy credit can be deducted from network electricity consumed on future bills at another time (e.g. in most US states, Brazil, Turkey and the Netherlands). The period over which these energy credits can be used (e.g. one year, one month) strongly influences the economic attractiveness for PV investors.

c. **Real-time self-consumption models:** PV owners can generate electricity for self-consumption and sell excess to the network (e.g. most Australian states and Denmark). While this appears similar to net metering, there are two main differences. First, energy accounting is done in real time (at hourly or less than hourly intervals). Second, PV owners are paid for each unit of electricity exported, rather than earning energy credits towards future bills. The price paid for exported electricity varies by jurisdiction and can be from zero to above the retail rate. In these models, remuneration rates range from wholesale to retail prices.

In essence, *Renewables 2019* categorises distributed solar PV remuneration schemes into five main categories: 1) buy-all, sell-all; 2) net metering; 3) real-time self-consumption at the wholesale price; 4) real-time self-consumption at a value-based price (usually between the wholesale and retail price), whereby utilities or regulators estimate the value of PV generation based on avoided generation capacity expansions, fuel expenditures and any additional costs, and on benefits to the system or society (grid integration costs, CO_2 reduction value, capacity credits, etc.); and 5) real-time self-consumption at zero remuneration.

The use of these schemes to increase distributed PV deployment varies by segment and region. Over 80% of residential growth during 2019-24 will be from buy-all, sell-all schemes or net metering, mainly in the United States and China. Conversely, the main driver for commercial growth is self-consumption in real time, largely because of the good match between electricity demand and peak PV production at midday. Value-based tariffs cover 30% of distributed PV growth up to 2024, especially driven by commercial systems in Europe and residential systems in Australia. Most US states, some countries in Europe, and relatively nascent markets such as Latin America and the Caribbean, India and Association of Southeast Asian Nations (ASEAN) economies are still implementing net-metering schemes that remunerate excess generation with retail tariffs.

Figure 2.6 Distributed PV remuneration for forecast growth, 2019-24



Notes: In buy-all, sell-all schemes, all PV generation is remunerated with a fixed tariff that can be higher or lower than the retail rate. No rem. = no remuneration of excess generation.

Countries use multiple policy tools to incentivise distributed PV applications. In some cases, PV owners are allowed to choose from among two or three policy alternatives targeting the consumption and sale of electricity (Table 2.4).

Table 2.4. Current distributed PV policy examples

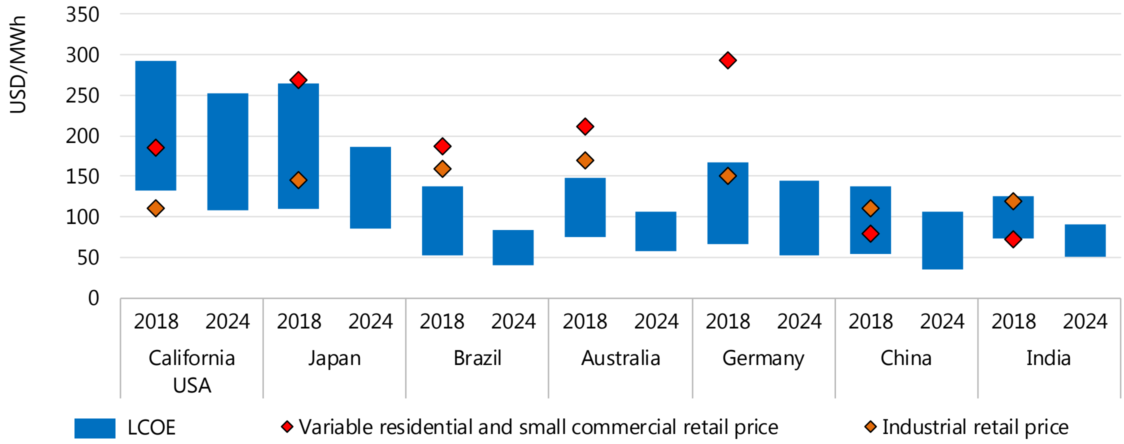
Country/ state/ province	Buy-all, sell-all model	Net metering		Real-time self-consumption models	
		Energy accounting	Remuneration of grid exports beyond energy accounting	Energy accounting	Remuneration of grid exports
China	Y	N	N/A	Y – real time	Value-based
New York (USA)	N	N	N/A	Y – real time	Value-based
California (USA)	N	Y – annual	Value-based	N	N/A
Germany		N	N/A	Y – real time	Value-based
Japan	Y	N	N/A	Y – real time	Value-based
Australia	N	N	N/A	Y – real time	Value-based
France	Y	N	N/A	Y – real time	Value-based
Spain	N	N	N/A	Y – real time	Wholesale or value-based
Turkey	N	Y – monthly	Value-based	N	N/A
Flanders (Belgium)		Y – annual	Value-based	Y	Zer0- to wholesale price
Netherlands	N	Y – annual	Retail	N	N/Al
United Kingdom	N	N	N/A	Y	Value-based
Maharashtra (India)	N	Y – annual	Value-based	N	N/A
Telangana (India)	N	Y – biannual	Value-based	N	N/A
Israel	Y	Y – monthly	Value-based	N	N/A
Viet Nam	Y	N	N/A	N	N/A
Chinese Taipei	Y	N	N/A	N	N/A
Sweden	N	N	N/A	Y – real time	Value-based
Denmark	N	N	N/A	Y – real time	Value-based
Italy	N	N	N/A	Y	Value-based
Indonesia	N	N	N/A	N	N/A
Thailand	N	Y – annual	Value-based	N	N/A
Philippines	N	Y – monthly	Wholesale	N	N/A
Mexico	Y	Y – annual	Value-based	Y	Wholesale

Economic attractiveness of distributed PV

While many factors can influence a customer's decision to install solar PV, the economic attractiveness of the investment – whether the investment will generate a financial return as well as electricity – is a key consideration. Policy, regulation and retail tariff design details directly influence the attractiveness of distributed solar PV and thus the pace of its deployment globally over the forecast period. Residential and commercial investors assess economic attractiveness by considering variables such as investment costs, the LCOE of PV generation, the variable component of the retail price, self-consumption rates and remuneration of excess generation.

Along with policy schemes, distributed solar PV costs have declined significantly, facilitating the adoption of residential, commercial and industrial applications worldwide. Since 2010, the LCOE of distributed PV has fallen 40-70% depending on the country, and reductions are expected to continue over the forecast period (Figure 2.7). *Renewables 2019* therefore anticipates distributed PV generation costs comparable to today's electricity prices, not only in most developed countries but also in an increasing number of emerging and developing economies.

Figure 2.7 LCOE for distributed PV systems, and variable residential, small commercial and industrial retail electricity prices, 2018/19



Source: IEA analysis based on IRENA (2019), *Renewable Cost Database*.

For the buy-all, sell-all model, the LCOE is the main indicator used to assess the economic attractiveness of distributed solar PV systems. Large distributed PV markets such as China, Germany, Japan and France offer fixed tariffs for all PV generation for 20 years (Table 2.5). In China, this model has propelled exponential expansion of commercial and industrial systems because the LCOEs of many systems have been lower than the tariffs offered. In Japan and Germany, however, tariff reductions have eroded the economic attractiveness of projects.

Table 2.5. LCOE range for commercial and residential systems and buy-all, sell-all tariffs, 2018/19

Country	LCOE range (USD/MWh)	Buy-all, sell-all tariffs (USD/MWh)	Contract length (years)
China	55-140	60-83	20
France	95-185	125-210	20
Germany	65-165	85-124	20
Japan	110-225	125	20

Note: In Germany, buy-all, sell-all tariffs are for small commercial systems of less than 100 kW only.

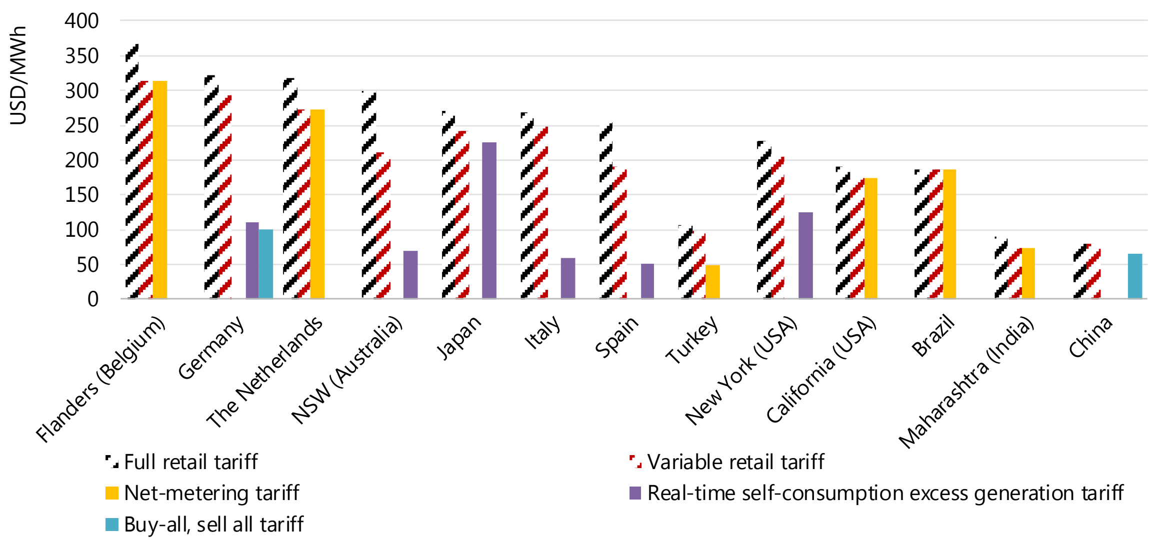
For net metering and real-time self-consumption models, the comparison of LCOE with retail electricity prices is only the first indicator of economic attractiveness. Three other variables are also important:

- **Length of energy accounting periods:** The length of net-metering energy accounting periods strongly influences economic attractiveness for private PV investors. The lengthier the accounting period, the more PV owners can apply their excess production as credit against what they consume from the grid. Accounting can be yearly, quarterly, monthly or daily; with annual accounting, for instance, PV owners can apply excess generation in the summer as a credit against net consumption in winter months.

- **Remuneration of excess generation:** Rates vary significantly across countries/states/provinces. They range from as low as USD 0/MWh in countries where there is no regulation, up to USD 230/MWh in Japan (Figure 2.8). Many countries are currently switching from retail- to value-based remuneration. In many European countries as well as some US and Australian states and China, compensation for excess generation is 20-80% below the variable retail price.

- **Evolution of variable retail tariffs:** A distributed solar PV application is expected to operate 20-25 years. During this period, retail price design may change, such that a higher share of revenues becomes fixed, reducing the future revenues of a net-metering scheme.

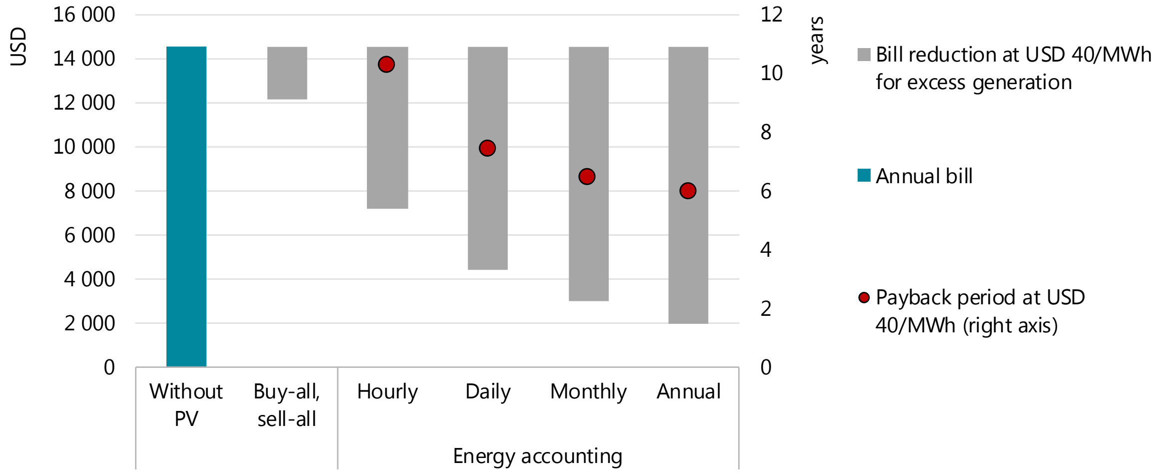
Figure 2.8 Full and variable retail electricity prices and residential PV remuneration prices



Note: NSW = New South Wales.

PV owners calculate their profitability based on how much they can save on their annual energy bills by not buying electricity from the utility. In this sense, the most profitable scheme (i.e. with the shortest payback period) for PV owners is net metering with annual energy accounting, as it provides the most retail credits for PV generation. If electricity generation from the PV system covers all annual demand, the PV owner pays only annual fixed charges. With shorter energy accounting periods, profitability declines because PV owners receive fewer retail credits and have to sell more electricity to the grid at below the retail rate (and lower remuneration for excess generation results in a longer payback period). In Figure 2.9, for instance, hourly energy accounting produces a 65% lower rate for excess generation and increases the payback period from six to ten years.

Figure 2.9 Annual bills and payback periods for small commercial PV systems under various energy accounting



Notes: Investment cost: USD 1 225/kWh.

Self-consumption and BTM storage: the combination of distributed solar PV and BTM storage can create economic value by increasing self-consumption or delivering services to the grid (ancillary services if PV is coupled with storage). Adding storage raises investment costs considerably, however, so additional revenue is required to recover the investment. Additional revenue can be gained by increasing the share of self-consumption or by using energy arbitrage to shift the sale of electricity to the grid to times when electricity prices are higher (peak hours). Government incentives may also help to recover part of the additional investment. The success of these measures depends on tariff design and time-based electricity pricing (time-of-use, peak and off-peak). In addition, the aggregation of multiple BTM storage units could provide ancillary services to generate additional revenue. Government subsidies have been the main driver for BTM storage in recent years, while costs have dropped by almost half since 2016.

Box 2.2. Deployment and cost trends for BTM storage

Falling technology costs, combined with incentives offered by many countries, have spurred significant expansion in BTM storage. Annual capacity additions more than doubled year-on-year in 2018, rising to close to 2 GW from only 100 MW five years ago (see figure below).

Korea had the most annual additions, followed by Europe and China. Although 92% of installations are concentrated in the top six markets, the share of additions in the rest of the world has increased rapidly.

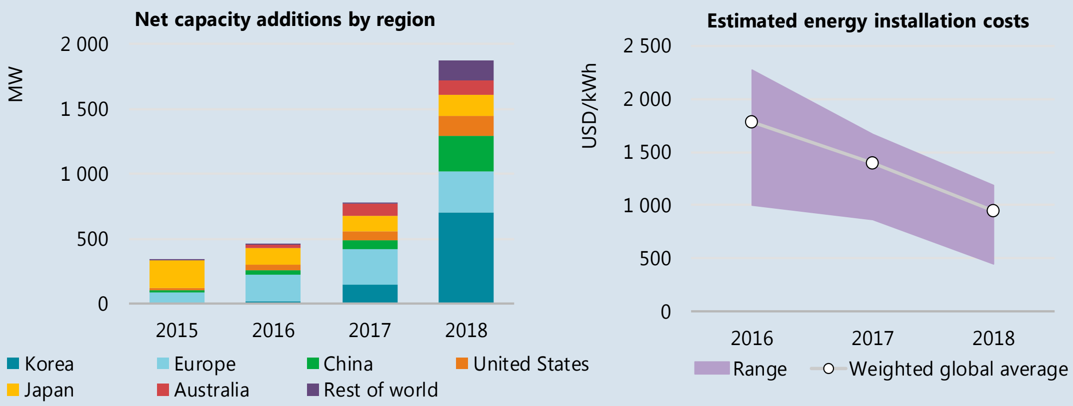
BTM capacity additions in Korea were driven by economic value, resulting from renewable energy certificates (RECs) and high wholesale power prices (USD 100/MWh). Solar PV projects with storage receive four to five RECs (valued at USD 66/MWh each) until 2020, expected to support rapid deployment of commercial applications in the short term.

Growth in Europe was led by Germany and Italy. Germany's BTM storage expanded even beyond the support of subsidy programmes, to over 100 000 installed systems (IEA, 2019a). In Italy, retail electricity prices for most residential customers are now much lower than remuneration granted for excess generation, so economics are driving BTM storage expansion.

China's BTM growth was driven by commercial/industrial applications benefitting from peak/off-peak tariffs. However, tariff design changes and safety concerns over energy storage in commercial buildings introduce a degree of uncertainty for future growth.

In the United States, a number of state-level policies and incentives are prompting growth, including New York's Climate Leadership and Community Protection Act, which aims to achieve a fully decarbonised energy supply by 2040, and California's Self-Generation Incentive Program, which has been extended to 2024. Other states, including Nevada, Massachusetts and Hawaii, have added or expanded their targets and support measures (IEA, 2019a)

Deployment and cost trends for behind-the-meter storage



Sources: IEA analysis, with calculations based on IEA (2019b), *World Energy Investment 2019*; Clean Horizon (2019), *Energy Storage Project Database*; CNESA (2019), *CNESA's 2018 Year in Energy Storage*; BNEF (2019a), Bloomberg Terminal.

Japan has been a leading market in the past five year. As the Residential Surplus Electricity Purchasing Scheme will be discontinued for half a million households in 2019, BTM storage may provide an option for them, raising self-consumption and enabling electricity bill savings.

Expansion in Australia has also been significant in recent years. As state government subsidies remain the main driver for residential storage growth, Australia is expected become the largest residential storage market (BNEF, 2019b).

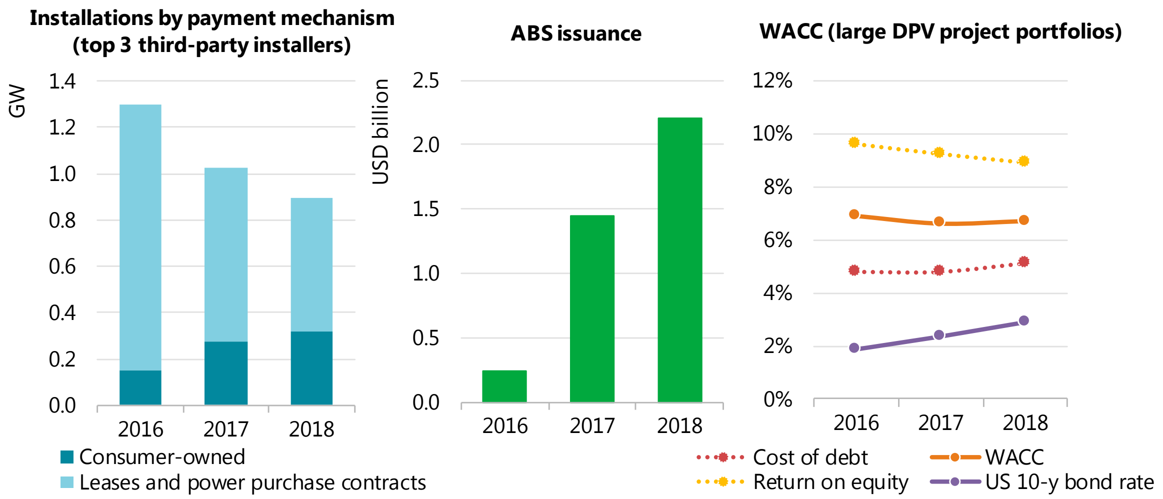
Remuneration schemes for exporting electricity to the grid will expire soon in a number of countries that supported distributed PV early on. This could spur growth in storage of self-produced electricity, as selling electricity to the grid will become less profitable than consuming it on-site. Plus, future regulations and frameworks allowing for the provision of ancillary services, demand-side management and aggregation of distributed BTM storage units may unlock additional revenue streams and drive further expansion.

Trends in financing and funding models for distributed solar PV

Most distributed solar PV investments are financed by consumers and companies (often supplemented by loans) who then own the systems, or through equipment leases and PPAs in which third parties install and retain ownership of the asset (Figure 2.10). Both models depend on the ability of the owner to commit significant capital upfront, which is then recovered over a number of years through electricity bill savings and other remuneration.

In the United States, the evolution of payment and financing options has been particularly dynamic, supporting a diversity of models. US investment in distributed solar PV was around USD 15 billion in 2018, the second-largest after China, and the market has remained one of the fastest-growing in terms of installations, despite capital costs that exceed the global average. In addition to federal and state policy support, the availability of financing has continued to improve, with more participants and products entering the market.

Figure 2.10 Payment mechanisms, securitisation and the cost of capital for distributed solar PV investments in the United States



Notes: ABS = asset-backed securities; WACC = weighted average cost of capital; DPV = distributed solar PV. WACC is reported for mid-cost systems and is expressed on an after-tax basis.

Source: IEA analysis, with calculations for ABS issuance based on Climate Bonds Initiative dataset provided to the IEA; WACC based on Feldman and Schwabe (2018), Terms, Trends and Insights on PV Project Finance in the United States, 2018 and Federal Reserve Bank of St. Louis (2019), *FRED Economic Database*.

Payment mechanisms in the United States are evolving towards increased consumer ownership. One-third of installations are third-party-owned, with a higher share in the residential sector, but the portion has declined in the past five years (Barbose and Darghouth, 2018). The top third-party installers now account for a smaller share of the market, and more of their sales are to consumers who purchase the distributed PV system outright (Figure 2.10).

This shift reflects more financing options for consumers and a desire by developers to reduce their own debt. Such pressure results from the significant upfront capital expenditures required, with investments recovered only over long periods through payments under leases or PPAs with consumers, creating a temporal mismatch between funding needs and revenues. Many financial institutions now offer solar loans, which have helped to facilitate direct ownership, with tenors of

7-25 years and interest rates of 2.5-7%. Consumers are also choosing to repay loans through their property taxes under the Property Assessed Clean Energy programmes that are now active in 20 states. The security provided by the tax mechanism reduces recovery risks for lenders.

At the same time, developers and financing companies are using secondary markets to refinance their own leases, contracts and solar loans, which redistributes financing costs and risks among more investors. In 2018, a record amount (over USD 2 billion worth) of ABSs based on existing US distributed solar PV projects was issued – equal to around 15% of total new investments in the sector.

All these developments have helped keep the cost of capital relatively steady. Broadly, the cost of financing for large portfolios of distributed PV projects remained stable (at a slightly lower level than two years ago) during 2018, even as US benchmark interest rates rose, with somewhat more debt used to finance projects and a greater variety of equity sponsors. Overall, market participants appear to be able to introduce new financial mechanisms into the market and to respond to changing risks quickly, suggesting that financing amplifies the effects of evolving policy conditions. Still, improving US distributed solar PV economics requires more financing options along with better project development (e.g. to reduce BoS costs) and industry maturation.

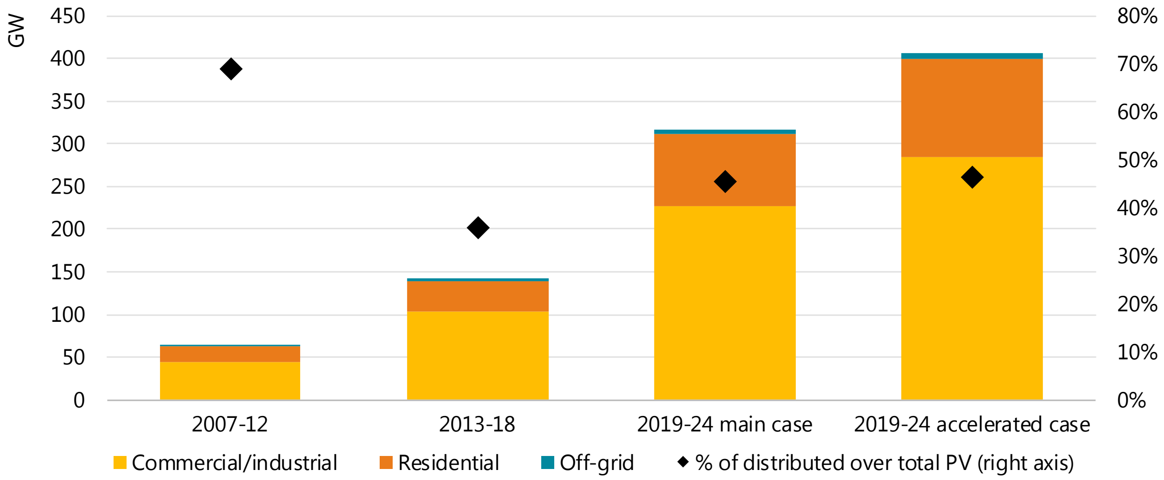
Trends vary considerably elsewhere. In Australia, another dynamic market, residential ownership predominates, with some payment models structured around leases and relatively fewer based on PPAs. Australia is one of the few markets outside the United States where developers have bundled and securitised portfolios of projects for refinancing by institutional investors. In Germany, most installations have been financed by consumers. Still, the KfW development bank has provided concessional financing to installations integrating battery storage, and several aggregation companies have recently begun to offer solar PV and battery systems on a PPA basis.

In emerging economies, consumers generally have higher credit constraints, and financing can be a considerable barrier in the absence of risk-mitigation measures. In such markets, local banks have limited lending capacity and tend to prefer the larger transactions associated with utility-scale projects. There is also a lack of frameworks in place to evaluate the creditworthiness of smaller companies and consumers. Consequently, in China the government has encouraged banks to make solar loans and green mortgages available to consumers at favourable lending rates (around 5%). In India, domestic lending capacity has been reinforced by development financing: preferential lines of credit of USD 625 million have been earmarked for distributed PV development by the World Bank, in collaboration with the State Bank of India, and another USD 100 million has been designated by the Asian Development Bank with the Punjab National Bank. While dispersal of these rooftop loans is currently under way, an acceleration in investment has yet to be seen.

Distributed PV forecast

Globally, distributed solar PV capacity is forecast to increase by over 250% during the forecast period, reaching 530 GW by 2024 in the main case. Compared with the previous six-year period, expansion more than doubles, with the share of distributed applications in total solar PV capacity growth increasing from 36% to 45% (Figure 2.11). Commercial and industrial systems remain the largest growth segment because they are usually more inexpensive and have a relatively stable load profile during the day that can enable larger savings on electricity bills, depending on the policy scheme in place.

Figure 2.11 Distributed PV capacity growth by segment

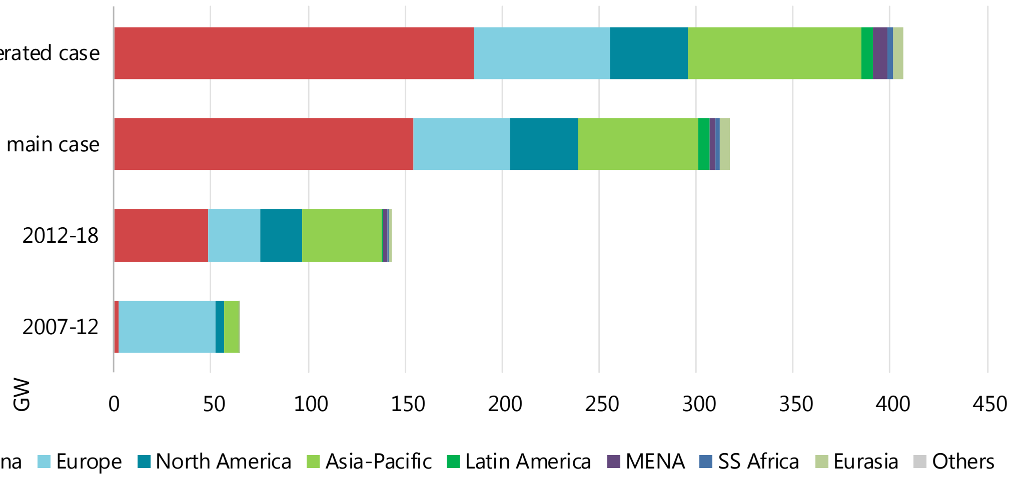


Over 30% of global installed PV capacity in 2024 is expected to be commercial and industrial applications. Residential systems account for 27% of all distributed PV expansion, as their significant growth (250%) over the forecast period is driven by high retail electricity prices and expanding policy incentives in both developed countries and emerging economies. Of all renewable technologies, additional growth potential is highest for distributed PV because consumer adoption can be very rapid once the economics become attractive.

Distributed PV growth could therefore be almost 30% higher in the accelerated case, assuming: 1) faster investment cost reductions, especially in countries where BoS costs remain high; 2) clarification of regulatory and incentive schemes in multiple markets, especially concerning remuneration and the length of self-consumption accounting periods; 3) the reduction of non-economic barriers such as protracted application processing, high connection fees and unjustified deployment caps; 4) access to affordable financing, especially in emerging economies; 5) speedy implementation of retail market reforms, enabling more cost-reflective electricity pricing for residential and commercial users.

China demonstrates the largest distributed solar PV growth over 2019-24, accounting for half of total capacity expansion, followed by the Asia-Pacific region, led by Japan and India (Figure 2.12). With clarification of the EU 2030 targets and formulation of countries' National Energy and Climate Plans, Europe's distributed solar PV expansion gains speed compared with the past six years, encouraged not only by high retail prices but by the lack of land available for large-scale utility projects. In North America, despite incentives diminishing at the federal level, state policies remain strong in the United States, while Mexico is emerging as a new growth market, especially for ratepayers with high consumption. Furthermore, distributed PV deployment is expected in many countries in Latin America, the Middle East and Africa as a result of expanding policy coverage and sustained cost reductions.

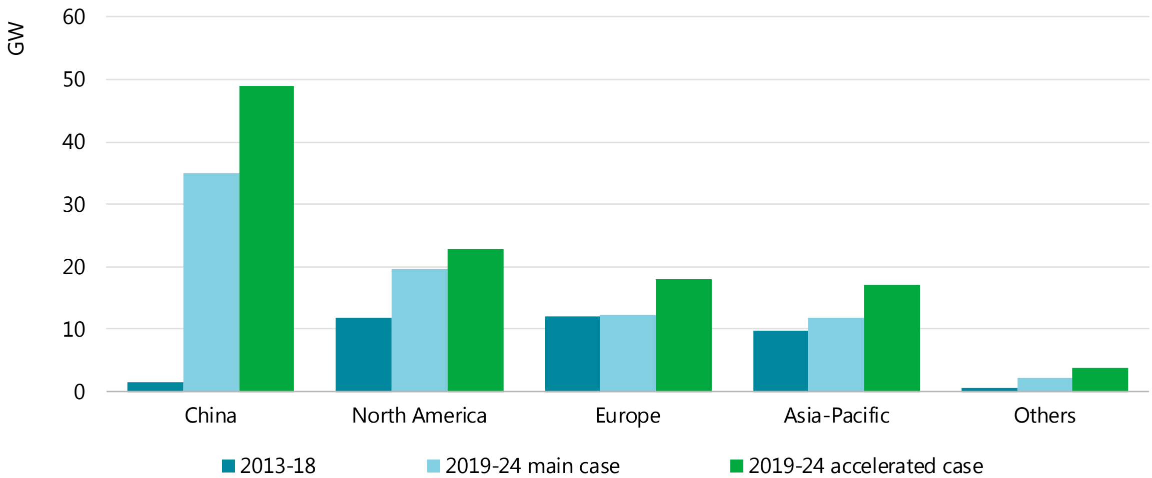
Figure 2.12 Distributed PV capacity growth by country/region



Residential PV forecast

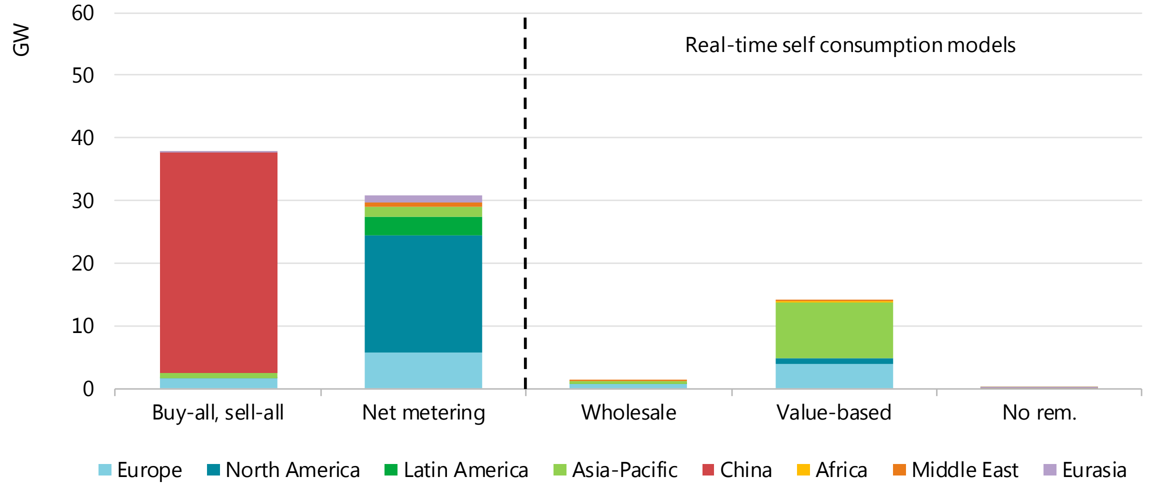
Residential solar PV capacity expands from 58 GW in 2018 to 143 GW in 2024, and annual capacity additions are expected to more than triple to over 20 GW by 2024. China's residential PV growth is forecast to accelerate substantially compared with the previous six years. As a result, the country registers the largest installed residential solar PV capacity in the world by 2024 thanks to FITs under the buy-all, sell all model, surpassing the European Union, the United States and Japan (Figure 2.13).

Figure 2.13 Residential solar PV capacity growth by country/region



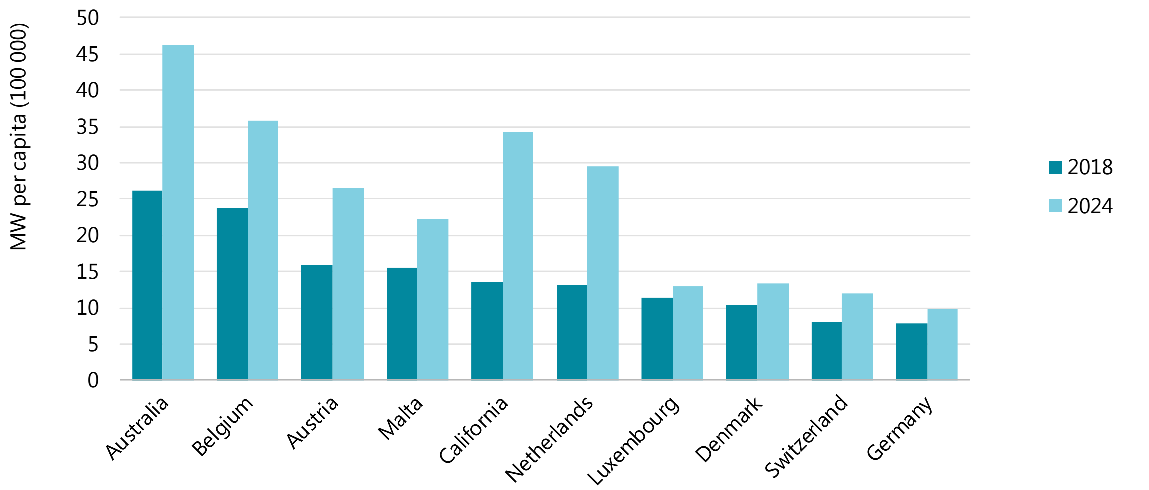
The United States is the second-largest growth market after China, with expansion driven by federal tax incentives and annual net-metering schemes in many states (Figure 2.14). In addition, California's new mandate requiring PV panels on new homes and buildings of up to three storeys after 2020 contributes to growth. Australia and Japan lead Asia-Pacific deployment, while growth continues to be limited in India and other emerging and developing countries due to minimal policy incentives, the absence of regulations (or their inadequate implementation), and low, cross-subsidised residential electricity tariffs, making the economics unattractive. In Latin America, residential expansion is expected to accelerate because of new net-metering and self-consumption policies in Brazil, Chile and Argentina.

Figure 2.14 Residential solar PV capacity growth by remuneration policy



Residential solar PV installation density can provide additional insights beyond the capacity deployed. In 2018, Australia, Belgium and Austria had the highest residential solar PV capacity per capita (Figure 2.15). By 2024, Australia and Belgium are still in the lead, but California and the Netherlands are expected to become the third and fourth markets in terms of residential PV installations per capita owing to rapid deployment over the forecast period.

Figure 2.15 Residential cumulative solar PV capacity per capita



China

China's residential PV capacity increases from an estimated 2 GW in 2018 to 37 GW 2024 in the main case. Its residential PV market is relatively nascent because government policies have focused mostly on large-scale utility or commercial PV projects, which have been economically more attractive. Residential retail prices are relatively low (USD 65/MWh to USD 90/MWh), making self-consumption economically unattractive in most provinces. However, the government's new policies have excluded small rooftop projects from the auction scheme and allocated a fixed additional subsidy of USD 27/MWh on top of the benchmark coal price (USD 45/MWh to USD 65/MWh) under the buy-all, sell-all model. Under the current subsidy cap, the annual residential rooftop market is expected to cover around 3.5 GW in 2019. In addition, some projects under the poverty alleviation programme are eligible for higher subsidies as part of the regional economic development budget.

Renewables 2019 expects these two major subsidy programmes to boost residential PV market expansion over 2019-24. However, financing residential systems remains a challenge in China and the third-party ownership model is restricted, hampering accelerated expansion. If access to affordable financing were enlarged and business models were improved, China's residential PV market could grow 40% more quickly under the accelerated case.

United States

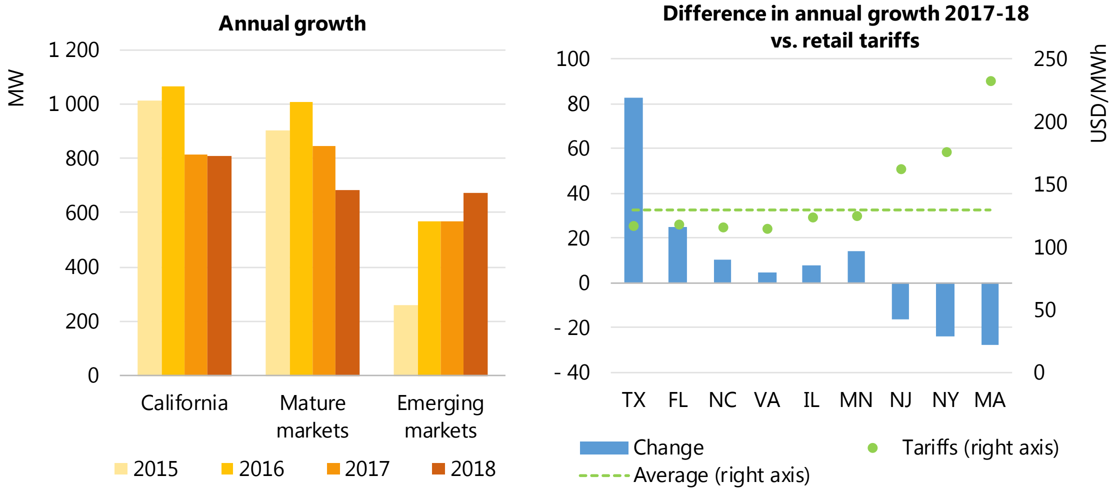
Residential solar PV capacity in the United States is expected to more than double over 2019-24, mostly because of net-metering schemes. Most of the growth is expected in California and new emerging markets where early-adopter[7] potential remains untapped (Figure 2.16). However, looming policy transitions and the high costs of acquiring new customers are challenges to faster growth.

The pace of deployment will be influenced mostly by California, the state that continues to lead the annual market. After a period of decline, annual growth is expected to rebound in 2019 as installers adjust pricing strategies to recent changes in rate structures (time-of-use pricing is required under the new net-metering scheme) and then accelerate from 2020 onwards as the rooftop mandate for new residential buildings enters into force.

Outside of California, growth is expected to continue shifting away from mature markets experiencing early-adopter saturation. Despite relatively high retail tariffs and robust policy support, annual growth slowed last year in Massachusetts, New York and New Jersey due to perceived market saturation and high costs for new customer acquisitions. Whether or not this trend continues over next five years is a key forecast uncertainty, particularly considering the ongoing policy transitions in these states. Both Massachusetts and New Jersey are reforming their renewable certificate schemes, while New York is switching from retail- to value-based remuneration for excess generation.

[7] Early adopters are customers willing to try a new technology soon after it becomes available on the market, before the majority of the population is ready to purchase it.

Figure 2.16 US residential solar PV capacity



Notes: Mature markets are the top nine markets for cumulative installed capacity in 2015 after California. TX = Texas; FL = Florida; NC = North Carolina; VA = Virginia; IL = Illinois; MN = Minnesota; NJ = New Jersey; NY = New York; MA = Massachusetts.

Source: Data adapted from EIA (2019), Monthly Electric Power Industry Report.

However, expansion in emerging markets that have lower residential PV penetrations is expected to offset falling growth in the north-eastern states, as the business case for self-consumption is improving at lower electricity tariffs due to falling system costs. Good solar resource potential, falling system costs and remuneration at retail rates with annual accounting of self-consumption prompted rises in annual growth in 2018 in Texas, Florida, Virginia and North Carolina, where tariffs remain below the national average. These states are expected to continue driving growth over the forecast period, and robust expansion is also expected in Illinois and Minnesota, where incentives for excess generation on top of net metering compensate for lower retail tariffs.

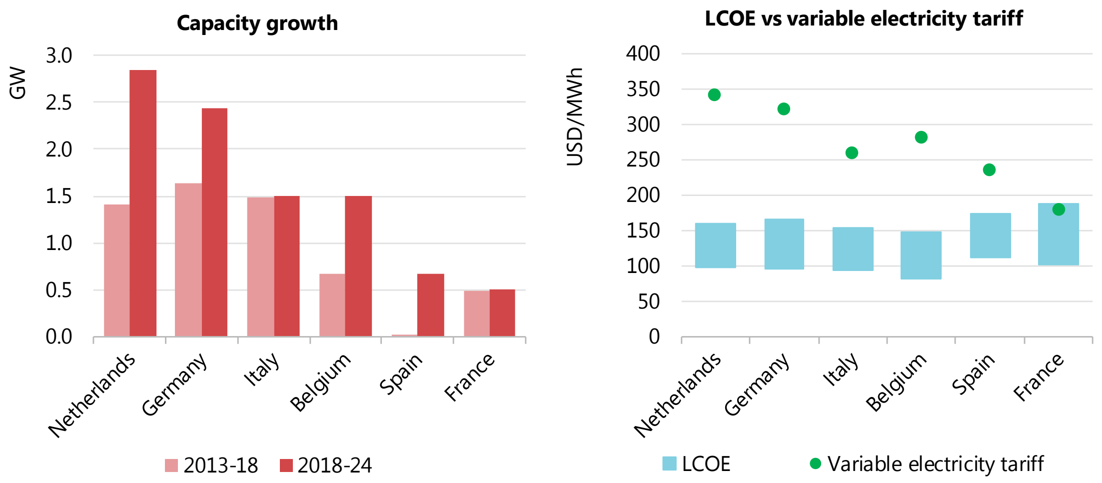
The Investment Tax Credit (ITC) remains an important stimulus for growth across all states, but how its phase-out over 2019-22 will affect national annual deployment levels is a forecast uncertainty. The ITC currently provides a 30% deduction on system costs for projects that begin construction by the end of 2019, but it will drop to 26% in 2020, 22% in 2021 and 0% in 2022. The impact is most uncertain in states where the phase-out coincides with policy transitions (the north-east) or reviews of net-metering rules (South Carolina, Connecticut and Kentucky). However, the forecast assumes that stable growth resulting from California's rooftop mandate will temper any slowdown in these markets. Should the project economics in these markets remain attractive post-ITC, residential PV growth in the United States could be 16% higher according to the accelerated case. In mature markets, maintaining economic attractiveness would require installers to adapt business models to the new policy environment to establish a new customer base, whereas in emerging markets it would be possible with stronger state incentives to offset any remuneration rate drops. Minimising permitting delays to reduce installation costs would also accelerate deployment across all markets.

Europe

Residential solar PV in Europe is forecast to expand by half (13 GW), with five markets accounting for almost 70% of deployment: Netherlands, Germany, Italy, Belgium, Spain, and France (Figure 2.17). Compared with the previous six-year period, the Netherlands overtakes Germany as the largest residential PV market owing to attractive net-metering economics derived from falling system costs, high retail prices and remuneration of excess generation at retail rates.

A substantial amount of residential growth in Europe is expected to be through net-metering or buy-all, sell-all schemes. However, self-consumption is increasingly important in the European Union due to rising electricity prices and the revised EU Renewable Energy Directive (2018/2001). The directive, which entered into force in 2018, seeks to create a more favourable environment for self-consumption by requiring member states to address financing and regulatory barriers to self-consumption of renewable electricity. The directive entitles renewable self-consumers to consume, store and sell excess generation from renewable sources. It also seeks to discourage any discriminatory charges by requiring fees to be cost-reflective and by banning double grid fees for storage. These regulations apply both individually and collectively to multi-tenant entities, third-party businesses, aggregators and renewable communities. Some member states recently enacted frameworks to facilitate the uptake of more self-consumption in the residential sector, but the co-existence of other support schemes (such as buy-all, sell-all and net metering) in some markets may complicate the business case.

Figure 2.17 Residential PV capacity growth, and LCOE in relation to retail electricity tariffs, 2018/19



Note: System costs in the Netherlands reflect VAT exemption (21%) for solar PV.

Residential PV capacity in the **Netherlands** is forecast to more than double during 2019-24 owing to attractive economics under the annual net-metering scheme, in addition to tax incentives. In 2018, the Netherlands led EU residential deployment with 600 MW, mainly for self-consumption in response to high electricity prices. The net-metering scheme provides energy credits for excess generation injected to the grid at variable retail rates, with annual energy accounting. When production exceeds total annual household demand, a further value-based price is paid per unit. In 2019, the scheme was extended to 2030, and long-term certainty is expected to ensure stable annual growth until the end of the forecast period. After 2023, fiscal incentives and net-metering tariffs are anticipated to gradually become less attractive.

Germany's residential PV capacity is expected to increase more than one-third, driven by attractive economics stemming from the combination of relatively high electricity prices, low PV system prices, and self-consumption with excess generation remunerated at fixed value-based tariffs (either administratively set tariffs or wholesale rates topped by a premium) providing revenue certainty (Figure 2.17). Rising electricity prices also increase the expectation that these policies will remain key enablers for growth over the forecast period.

The forecast was revised upwards from *Renewables 2018* after a proposal to extend policy support for distributed PV was announced. Support for remunerating electricity exported to the grid was set to expire when cumulative installed PV capacity reached 52 GW (estimated to happen between 2020 and 2021), but the recently released 2030 Climate Plan proposes to lift this cap and extend support. The proposal still needs to be ratified by parliament, but the main case forecast expects this provision to be passed, supporting stable residential PV growth. Recent regulatory changes could pose a challenge, however: in 2018, fixed tariffs were reduced unexpectedly, as were the annual deployment caps, triggering deviations from normal levels. This, coupled with a lack of long-term certainty over support for battery storage, could challenge the economics for residential systems. Growth could be two-thirds higher if the economics for self-consumption improve more quickly.

As in *Renewables* 2018, **France**'s residential PV capacity is expected to increase by more than one-third by 2024. PV owners can benefit from two policy schemes: buy-all, sell-all, and self-consumption with injected generation remunerated at a premium to retail electricity prices. Due to low retail electricity prices, the main driver for growth is expected to remain the buy-all, sell-all scheme; however, self-consumption may make up a larger share of growth if it becomes economically attractive and consumer awareness improves. This will depend on the interaction between electricity tariffs and the recently passed support measures: in 2017, a series of measures was passed to improve the self-consumption framework for systems < 100 kW – such as exemptions from the renewable surcharge, investment grants, tax reductions and reduced grid connection fees. However, limited consumer awareness of this support for self-consumption, coupled with low retail rates, has caused investments to be focused on the buy-all, sell-all scheme. Residential growth could be 50% higher if the economics for self-consumption and consumer acquisition rates improve, which would require a sustained rise in electricity prices and the effectiveness of the #PlaceAuSoleil executive plan. The plan extends the renewable surcharge exemption for self-consumption projects, allowing collective self- consumption within a 1-kilometre radius, and will facilitate third-party leasing. It also aims to increase auction volumes for PV installations above greenhouses and crops (agri-PV) and on rooftops.

In **Belgium**, the residential sector is still the country's largest PV segment and it is expected to expand by more than half. The net-metering scheme remains attractive for systems under 10 kW, while larger residential applications benefit from self-consumption paired with guaranteed payback after 15 years at a 5% internal rate of return (IRR) through green certificates. Under the accelerated scenario, growth is 40% higher, assuming accelerated uptake under the new net-metering scheme in Wallonia and faster growth in support of the country target submitted to the European Union (for roughly 8 GW by 2025).

Residential PV capacity increases by more than one-third in **Italy** over 2019-24, driven by the lucrative combination of self-consumption with value-based remuneration and tax breaks.

Growth in the segment is 20% higher in the accelerated case when additional benefits for self-consumption under the new renewables decree supporting the 2030 EU target of a cumulative 50 GW of PV are factored in.

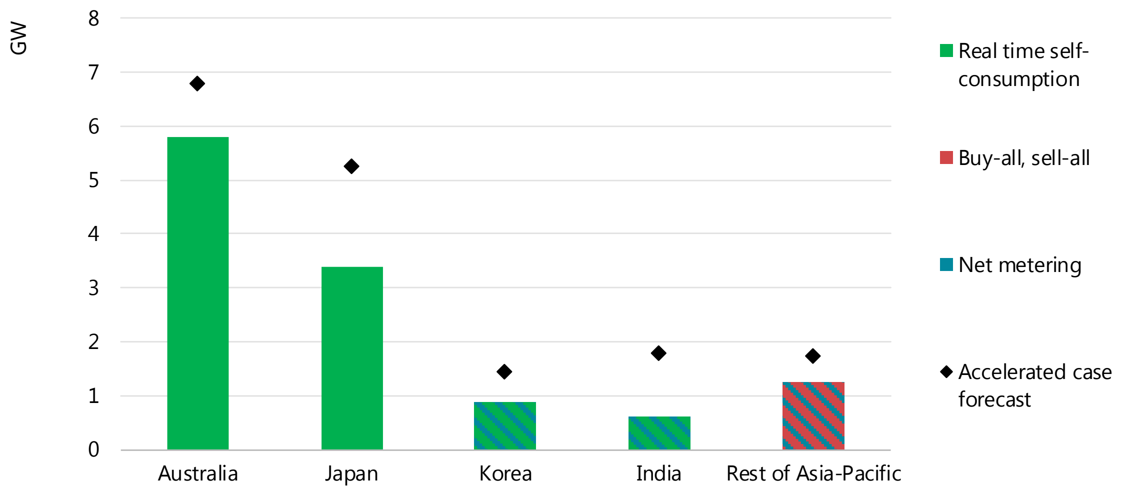
Spain's residential PV segment is expected to expand more than twice as much as forecast in *Renewables 2018* owing to an improved self-consumption framework from recent regulatory reforms. Prior to the reforms, obtaining remuneration for residential systems required a complex administrative process to register them as generators, and remuneration for excess generation was available only at wholesale rates. The recent measures simplify the process for systems of < 15 kW by requiring only one registration and ensuring connection within 15 days. In addition, the introduction of retail rates for remuneration with hourly accounting and rising electricity prices are also expected to make residential PV more economically attractive. Growth could be more than 80% higher if consumer risk perception (shaped by previous policies that discouraged self-consumption) were reduced. Greater collective self-consumption, introduced in the recent reforms, would also accelerate deployment.

In **Poland**, the residential PV segment is forecast to almost double (to 0.5 GW by 2024) as electricity prices rise and net metering becomes more widely available. Currently, installations of up to 10 kW receive 0.8 W back for each watt injected to the grid, while installations of up to 50 kW receive a 0.7-W credit. Net-metering customers have 12 months to use their credit, but the country is amending its system to allow more clients to participate and to extend credit validity from 12 months to 24, making self-consumption increasingly attractive.

Asia-Pacific

Residential PV capacity in the Asia-Pacific region (excluding China) expands 70% (12 GW) over the forecast period, driven by self-consumption models, with value-based remuneration in Australia and Japan, net metering in India, Korea and other ASEAN countries, and a buy-all, sell-all scheme in Chinese Taipei (Figure 2.19). Growth is 43% (17 GW) higher in the accelerated case, however, led by Australia and Korea and by more rapid adoption by residential customers in India with supportive distribution companies (DISCOMs) and new financing solutions.

Figure 2.18 Asia-Pacific residential PV capacity growth, 2019-24



Australia remains the largest market for residential solar PV in the Asia-Pacific region, with its capacity forecast to double to almost 12.5 GW by 2024. Under the Small-scale Renewable Energy Scheme (SRES), the federal government offers an upfront subsidy of USD 460/kW, or almost one-third of average total installation costs in 2018/19. The SRES will phase down through 2030, but whether the pace of system cost declines will directly offset subsidy reductions remains a forecast uncertainty.

High retail prices have been key in motivating people to install PV systems to reduce their energy bills. Retail prices in Australian states range from USD 150/MWh to USD 250/MWh including all transmission and distribution costs, which are charged both as a fixed and as a variable component of electricity bills. Overall, the variable part of the bill, which reflects actual savings from self-consumption, makes up around 65-75% of total residential bills. Remuneration of excess generation in many Australian states is value-based and updated annually by state regulators. Retailers are allowed to compete, offering different remuneration tariffs for excess generation, usually ranging from USD 70/MWh to USD 100/MWh with higher and lower rates available under certain retail price structures. Higher FITs are often offset by higher fixed daily charges, making Australia one of the most advanced countries in terms of retail market liberalisation as well as integration of distributed solar PV. As a result, in some states such as Queensland and South Australia, one-third of all freestanding dwellings have rooftop solar PV installed. Local midday grid integration challenges have emerged, however, as residential demand is low at this time and the majority of solar generation is exported, increasing night-time ramping requirements.

Japan remains the second-largest residential PV market in the Asia-Pacific region as a result of the generous FIT it provides for excess generation. With the recent reduction to the FIT in 2019, however, it is now lower than the variable retail rate in many regions. This development is expected to promote self-consumption but can also affect economic attractiveness negatively. In addition, the number of FIT approvals over the forecast period is expected to decline significantly compared with the 2012-15 period, resulting in stable annual growth of 560 MW through 2024.

In 2019, half a million households will no longer be eligible for the Residential Surplus Electricity Purchasing Scheme introduced in 2009, under which utilities bought excess generation at a fixed price (USD 485/MWh) for ten years (METI, 2019). According to new regulations, remuneration for PV owners under the old scheme will drop by 80%, a measure that is expected to promote self-consumption for residential customers. For the residential segment, the potential for additional capacity expansion in Japan is limited and will depend on FIT approvals and the economic attractiveness of storage, which will improve the business case for self-consumption.

Korea's residential growth forecast has been revised upwards from *Renewables 2018* owing to ongoing subsidy programmes for residential PV installation; net metering to reduce electricity bills; and a new strategic policy for renewables announced in April 2019, allowing residential PV owners to sell surplus generation at a REC multiplier of 1.0 after self-consumption. This legal amendment is expected to be implemented by the end of 2019.

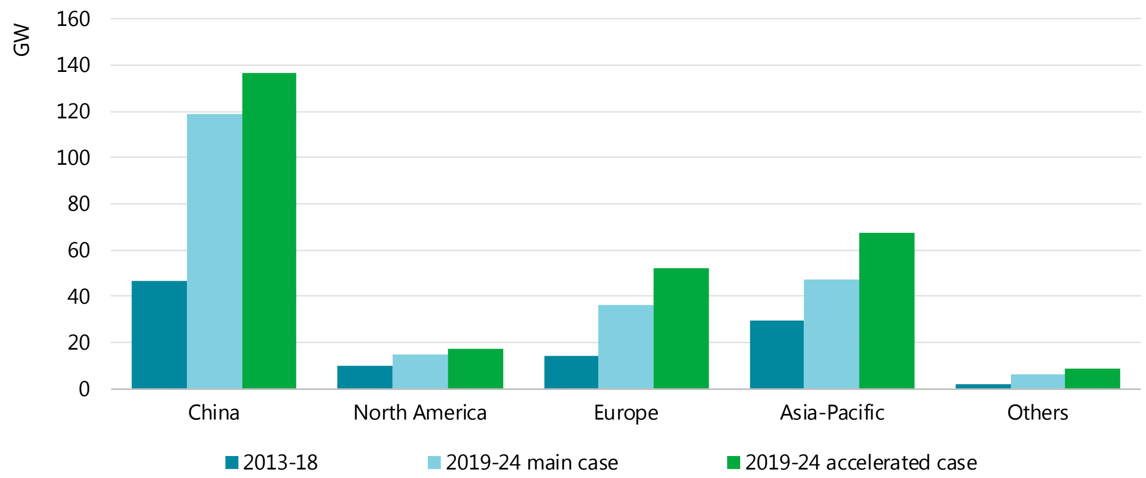
In **India**, the nascent residential PV market is expected to more than double, growing by 600 MW over 2019-24 with high self-consumption by residential customers. However, expansion is limited somewhat by cross-subsidisation of residential electricity tariffs and the resulting lack of commercial interest by the DISCOMs in losing the most valuable residential customers in the higher-consumption categories. Furthermore, improved access to financing and viable third-party business models at scale could result in threefold growth (1.8 GW), reflected in the accelerated case.

Residential PV in **Chinese Taipei** expands threefold over the forecast period, driven by the generous FIT under the buy-all, sell-all scheme. Nevertheless, the forecast has been revised down slightly to reflect the 2019 FIT reduction and those expected in the future. Under the accelerated case, growth is 5% higher, reflecting wider adoption by residential customers. However, a lack rooftop availability and low retail electricity rates limit further growth.

Commercial/industrial

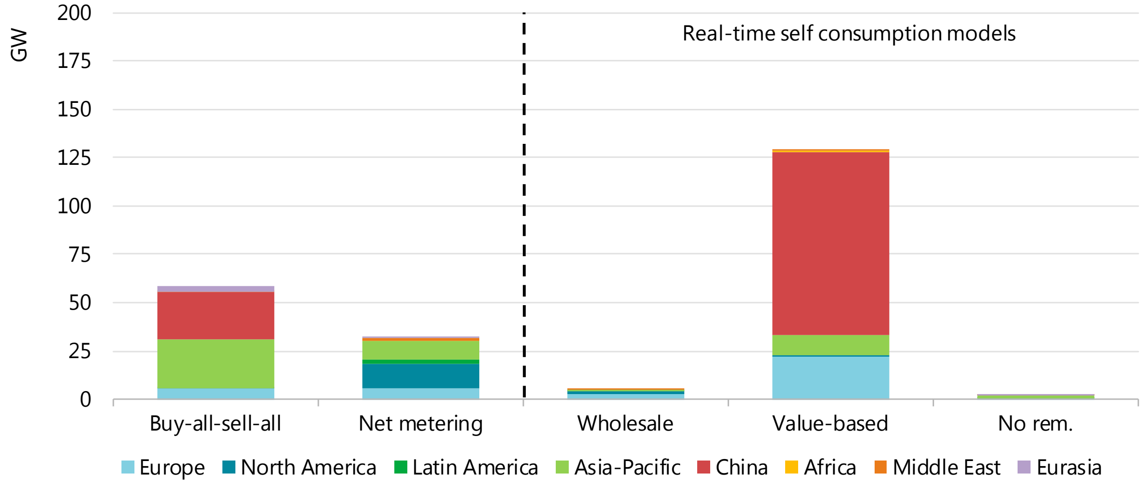
Commercial and industrial solar PV capacity is forecast to expand from 150 GW in 2018 to 377 GW in 2024, with annual capacity additions increasing by 50% to 44 GW in 2024. China remains the largest growth market, but unlike for the residential segment, expansion in the Asia-Pacific region is larger than in Europe and North America, mainly owing to strong policy incentives in Japan, Korea and India (Figure 2.19). In the European Union, commercial PV growth in the main case forecast accelerates compared with the previous six-year period, thanks not only to sustained deployment in Germany but also to emerging growth markets such as France, the Netherlands and Spain as a result of improved policy environments.

Figure 2.19 Commercial and industrial solar PV capacity growth by region/country



Real-time self-consumption models with value-based tariffs are the engine of commercial and industrial PV growth globally, mostly due to a policy shift from FITs to competitive auctions in China (Figure 2.20). Outside of China, a combination of remuneration policies is implemented in Europe, with value-based tariffs dominating, while net-metering schemes remain popular in the United States. In Asia-Pacific, buy-all, sell-all models with generous tariffs in Japan, Chinese Taipei and Korea, real-time self-consumption with value-based tariffs in Australia, and net metering in India are the key drivers of growth.

Figure 2.20 Commercial and industrial solar PV capacity growth by remuneration policy



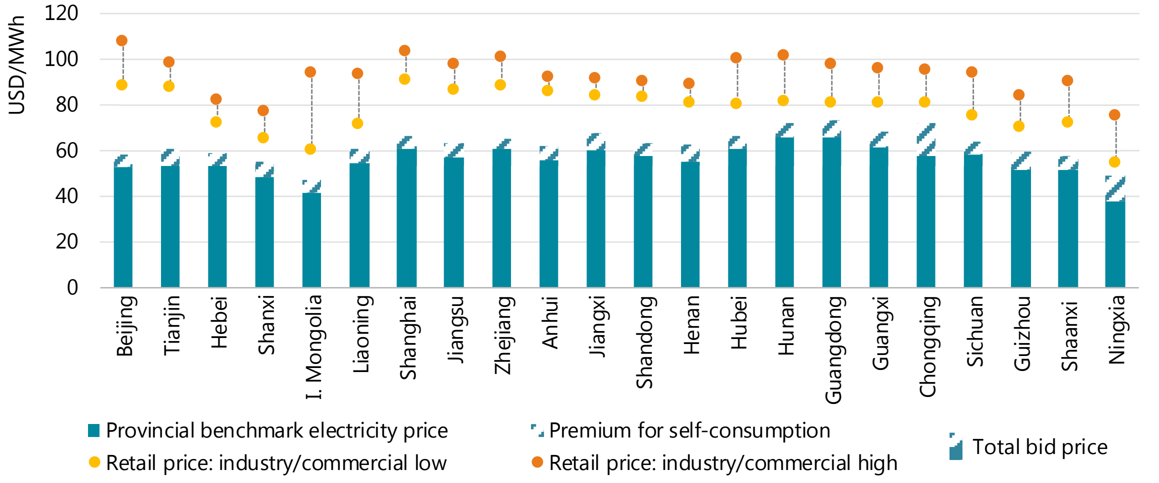
China

China's commercial and industrial PV capacity is expected to more than triple, reaching over 168 GW by 2024. The government has been promoting large-scale distributed solar PV applications closer to demand centres to alleviate curtailment. In 2018, commercial projects accounted for over 45% of total PV capacity additions, spurred by the previous FIT scheme, which ranged from USD 75/MWh to USD 105/MWh. Commercial/industrial PV owners have two options under the new incentive scheme: under the buy-all, sell-all model, they are required to compete for subsidies as part of the new auction scheme, but auction ceiling prices are lower than the previous FITs (from USD 59/MWh to USD 82/MWh). Or, under the self-consumption and excess generation model:

- A developer's bid price comprises the provincial benchmark electricity price based on coal-fired power and a fixed premium for self-consumption.
- For self-consumed electricity, system owners save the variable portion of the retail electricity price on their bills, plus receive the fixed premium defined in the auction.
- For electricity injected into the grid, system owners receive the total bid price.

In the first PV auction held in July 2019, almost 90% of the 4.7 GW of commercial and industrial PV projects chose the self-consumption model. Bid prices ranged from USD 47/MWh to USD 72/MWh, while the self-consumption premium was between USD 4.5/MWh and USD 11/MWh (Figure 2.21). Commercial and industrial retail rates are 20% to 200% higher than average bid prices, depending to what degree the province makes self-consumption model profitable, resulting in relatively short payback periods as China's investment costs are among the lowest.

Figure 2.21 Distributed PV bid prices in China under the self-consumption model in 2019, compared with retail electricity rates



Commercial/industrial capacity expansion is anticipated to contract slightly during the policy transition to competitive auctions, but to regain momentum after 2021. Most industrial and large commercial customers are able to consume most of their PV generation because their daytime loads are stable, making self-consumption economically attractive. In addition, the new regulation allows PV owners to sell their excess electricity to other consumers within the same distribution area.

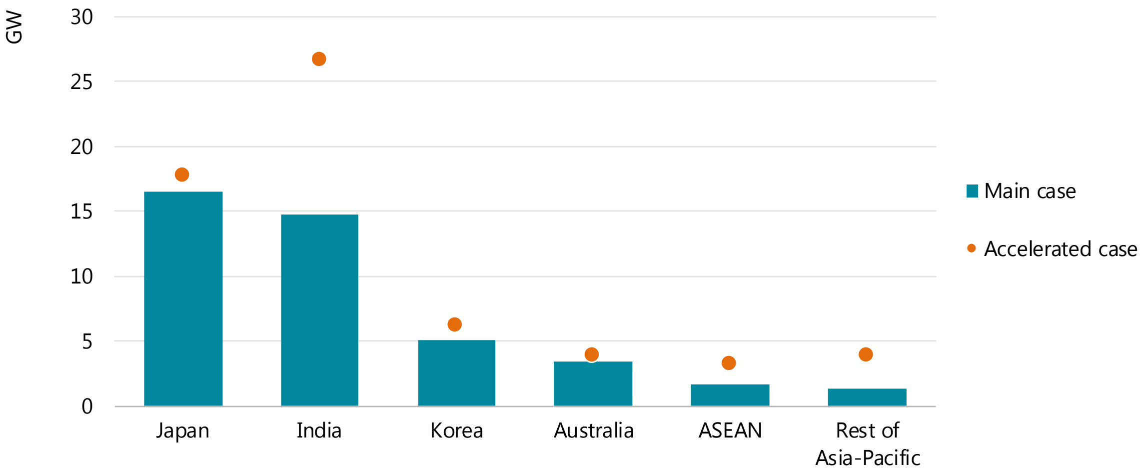
Asia-Pacific

The Asia-Pacific region is responsible for one-fifth (47 GW) of global commercial PV expansion during 2019-24, encouraged by a range of administratively set incentives, net-metering schemes, third-party PPAs and leasing models, as well as pure self-consumption business models (Figure 2.22). Japan and India are expected to lead growth, followed by Korea, Chinese Taipei, Australia and ASEAN economies. Enhanced access to financing and inclusive business models, regulatory certainty and removal of administrative barriers could result in 50% (67 GW) higher growth, as modelled under the accelerated case.

Japan's commercial PV growth is propelled by both FITs and auction schemes. The forecast has been revised up from last year to reflect the inclusion of large commercial/industrial applications (over 500 kW) in the auction scheme in 2019. In addition, *Renewables 2019* has adjusted direct current/alternating current (DC/AC) assumptions based on new data, resulting in greater DC capacity over the forecast period. After their recent downward revision, FITs are generally lower than commercial retail electricity prices, encouraging PV owners to self-consume more to reduce their electricity bills. It is therefore assumed that an increasing number of commercial system owners will choose to participate in the Surplus Electricity Purchasing Scheme instead of selling all electricity under the buy-all, sell-all model.

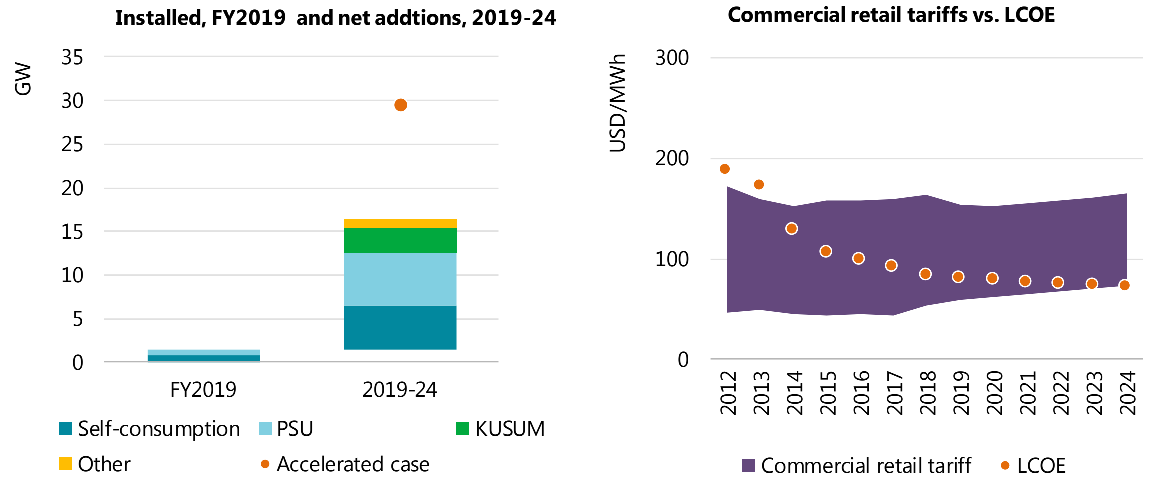
In Korea, commercial rooftop solar PV plants below 3 MW receive 1.5 RECs on top of the wholesale power price (system marginal price) for all electricity generation. Although REC and electricity prices fluctuate, average monthly remuneration varied from USD 160/MWh to USD 200/MWh in 2018. In addition, commercial and industrial PV installations combined with storage, discharging during non-peak times, currently receive five RECs (declining to four RECs in 2020), making the projects economically attractive. Uncertainty over the price of electricity and RECs in the long-term remain challenging for project financing, but remuneration is generous. In addition, a temporary FIT programme for small-scale PV (mainly less than 30 kW) will also be available until 2022. The FIT programme offers a fixed-price contract for 20 years at USD 170/MWh, and this generous tariff is expected to improve the bankability of small-scale commercial PV systems (IEA PVPS, 2019).

Figure 2.22 Asia-Pacific commercial PV capacity growth, 2019-24



In **India**, commercial PV capacity is expected to increase fivefold (15 GW) by 2024, led by projects developed on state-owned premises (public sector undertakings, or PSUs) (Figure 2.23). One-third of growth is in self-consumption installations under consumer and third-party ownership, while one-fifth is in grid-connected solar pumps under the KUSUM scheme. So far, installed commercial PV installations are equally divided into PSU and commercial rooftop installations for self-consumption, with or without remuneration for excess generation.

Figure 2.23 Distributed PV in India and target for 2022 fiscal year



Notes: FY = fiscal year. *Other* includes corporate PPAs and aggregated rooftop auctions for the commercial sector.

Source: MNRE (2019), FAQ: Grid-connected solar rooftop system.

PSU projects are expected to contribute most of the commercial distributed capacity growth owing to the availability of central government funding and greater transaction sizes for PSU tenders. However, slow uptake by governments and undersubscribed tenders resulting from domestic-content requirements remain challenging. A major obstacle to self-consumption in the commercial sector continues to be the caution shown by DISCOMs: they are losing their most valuable customers, who are critical for the functioning of cross-subsidised electricity tariffs. Inclusive business models that leverage the strengths of DISCOMs in consumer aggregation, billing efficiency and reliable payment history could provide new revenue streams for DISCOMs, resulting in greater acceptance.

Further growth in deployment of grid-connected solar pumps is expected through the KUSUM scheme, state-level rooftop auctions and, later in the forecast period, under corporate PPAs. In the accelerated case, expansion could be almost twice as high (30 GW) if access to financing is improved, conducive regulations are passed, DISCOMs more quickly enable self-consumption for their customers, and the PSU and KUSUM schemes achieve their ambitious targets.

In the **ASEAN** region, **Thailand** leads commercial PV expansion with fourfold growth during 2019-24. The pilot rooftop scheme, the second phase of the solar incentive programme for government agencies and agricultural co-operatives, and the forthcoming solar rooftop policy enabling three new modes (self-consumption, third-party PPAs and remuneration of excess generation by state utilities), as well as the global trend of rising cost-competitiveness, will drive growth. In the **Philippines**, the beginning of commercial PV deployment (550 MW) is expected to be spurred by the economical attractiveness and reliability of supply of self-consumption for commercial installations, and by some on-site corporate PPAs. **Indonesia**'s first commercial PV installations are also forecast (270 MW), but the recent net-metering regulation will need further refinement to spark higher growth. While **Viet Nam** is a regional hotspot for other renewable technologies, distributed PV is not expected to expand significantly after the abandonment of net metering. The accelerated scenario demonstrates more than twice the growth for ASEAN countries if all described challenges are addressed.

Europe

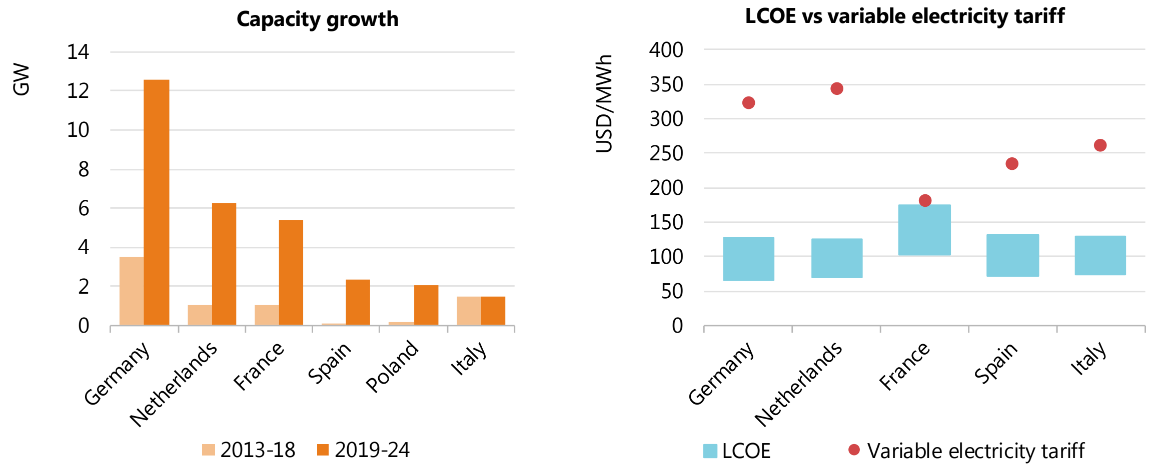
Commercial solar PV in Europe is forecast to grow by two-thirds (37 GW), with six markets (Germany, France, the Netherlands, Spain, Poland and Italy) accounting for 80% of deployment over the forecast period (Figure 2.24).

Germany's commercial PV capacity increases almost by half over 2019-24, stimulated by self-consumption with remuneration for excess generation becoming more economically attractive, thanks to high electricity prices and falling system costs. Approximately one-third of growth is expected to be from smaller systems (< 100 kW) eligible for a value-based fixed tariff for remuneration, while the remaining majority is from large commercial systems (> 100 kW) that are required to use the market premium model that remunerates excess generation at wholesale prices topped by a premium. In both cases, self-consumption of at least 10% is required for systems of > 10 kW and will be the main driver for growth. Also boosting growth is the recent proposal to extend policy support beyond the subsidy cap of 52 GW total capacity. However, the impact of recent policy changes on deployment remains a forecast uncertainty. The latest energy act, passed in November 2018, revised remuneration rates downwards and introduced faster decreases in remuneration levels over 2019-24. Growth is two-thirds higher in the accelerated case if the business case for self-consumption improves more quickly for smaller commercial systems.

In the **Netherlands**, commercial systems are the largest contributor to solar PV market growth. Cumulative capacity increases fourfold over 2019-24, driven by projects awarded support through Sustainable Energy Production (SDE+) auctions. The SDE+ provides a maximum 15-year variable remuneration rate for generation for systems of 15 Kw and over, covering the difference between the awarded tariff and the market price. Different payment levels exist for exported and self-consumed electricity.

The forecast has been revised up significantly from last year to reflect the strong performance of solar PV in 2018 SDE+ auctions, supplementing a project development slate that was already robust. Projects must be delivered 1.5 to three years from the time they are awarded, depending on capacity. Although the SDE+ is set for revision after 2020, the forecast assumes it will still offer support for solar PV, given the need to scale up renewable electricity generation significantly to meet the 2030 National Energy and Climate Plan goals. However, delivering anticipated growth is likely to require grid reinforcement in the northern and eastern regions, and potentially more widely. Growth could be 2.5 GW higher under the accelerated case, assuming grid constraints are avoided and ongoing generation and investment cost reductions for rooftop systems strengthen self-consumption economics.

Figure 2.24 European commercial PV capacity growth, 2019-24, and LCOE in relation to variable retail electricity tariffs, 2018/19



The forecast for **France** has been revised up by one-third from *Renewables 2018* owing to increased support for competitive auctions for rooftop systems in the latest long-term energy plan. Over 80% of growth is in large rooftop systems (> 100 kW) from competitive auctions for fixed remuneration rates (PPAs) for all generation. More than 800 MW of rooftop capacity was awarded in the first five rounds, driving the average winning bid price (USD 92/MWh) down almost 30% since the first auction in 2017. Outside of auctions, the increasing economic attractiveness of self-consumption for small commercial systems is expected to spur additional growth. Falling system costs, coupled with investment grants, exemptions from taxes and renewable surcharges, remuneration of excess generation and rising electricity prices improve the self-consumption business case for systems of < 100 kW.

However, auction design is emerging as an obstacle to faster deployment for large commercial systems (> 100 kW). For buy-all, sell-all rooftop auctions (for PPAs), undersubscription may pose a risk in the future because of high auction frequency and complex administrative processes. This was evident in the sixth auction, in which the average winning price was 10% higher than in the previous auction. In addition, a lack of competition caused the recent suspension of the new technology-neutral competitive self-consumption auction scheme. Only half of the 300 MW on offer over six rounds was awarded due to an auction design that favoured high rates of self-consumption (> 95%), making the economics unattractive for most commercial systems. Overall, commercial growth in France could be one-third higher under the accelerated case if the initiatives outlined in the #PlaceAuSoleil plan are implemented to ensure auctions are fully subscribed and the framework for self-consumption is improved. Among other measures, the plan aims to streamline administrative procedures, permit third-party leasing and shared generation, and continue to exclude self-consumption from the renewables surcharge.

Spain's commercial growth has been revised up by over 90% from *Renewables 2018* owing to regulatory reforms aimed at improving the economics of self-consumption with remuneration for excess generation. The main change is the removal of charges on self-consumed electricity for systems of > 10 kW introduced in 2015 (Royal Decree 900/2015). The removal of these charges, coupled with falling system costs, is expected to drastically improve economical attractiveness and accelerate deployment. Also supporting a more optimistic forecast is an improved business case for self-consumption in small commercial systems (< 100 kW). Prior to the 2018 reforms, remuneration was limited to wholesale rates and registering for support was a complex procedure. The new reforms simplify the administrative process and introduce the option of remuneration at value-based rates with hourly accounting. Rising electricity prices are also expected to improve the bankability of commercial systems for pure self-consumption. Faster rises in electricity rates result in 20% more growth in the accelerated case.

Commercial PV is expected to lead **Poland**'s PV growth, adding 2 GW of capacity during 2019-24 as a result of regularly held auctions for projects under 1 MW and planned adjustments to the net-metering system. Poland is working on extending net-metering availability from residential users only to small and medium-sized enterprises (SMEs) and agriculture entities. Rising electricity prices, falling module costs and wider net-metering availability increase the attractiveness of self-consumption and stimulate growth.

Commercial PV capacity in **Italy** is forecast to expand 13% over 2019-24, driven by the economic value of self-consumption and the investment support offered by white certificates and over-amortisation. Additional support for PV self-consumption under the new renewables decree could result in 40% more capacity in the accelerated case, further strengthened by the expected hike in retail electricity rates.

United States

Commercial solar PV capacity in the **United States** is forecast to more than double, increasing by 13 GW over 2019-24, as economic attractiveness increases with falling system costs and retail-rate remuneration for most excess generation. Annual additions are expected to slow in 2019, as growth returns to levels prior to the peaks in 2017 and 2018, which had been caused by looming policy transitions in California and Massachusetts. In California, developers rushed to lock in previous time-of-use rates before the new rates shifted peak pricing to later in the day, when most commercial systems are less likely to be exporting excess generation. In Massachusetts, consumers hurried to install before the transition from market-based to fixed remuneration rates that decrease by deployment level. Growth is expected to return in 2020 as these two markets adjust to the new policy environment, and it will continue until 2024 from community solar installations in New Jersey, Illinois and Minnesota. However, changes to incentive schemes, volume caps on incentives and net-metering reforms may challenge the pace of deployment in major markets. In newer markets, limits on system size for net-metering eligibility pose a threat to forecast expansion. Should faster system cost reductions offset the impacts of policy transitions, growth could be 14% higher in the accelerated case.

Middle East and North Africa (MENA)

Commercial solar PV in the **MENA** region is expected to more than triple, rising to 3 GW over the forecast period, led by the United Arab Emirates, Israel, Morocco, Egypt and Jordan as costs fall, electricity subsidies are gradually removed and supportive policy schemes are introduced. Net-metering is expected to drive the growth in most of the countries with additional deployment from buy-all, sell-all schemes and rooftop tenders in Israel. Aside from Israel, large systems greater than 1 MW are common in MENA's commercial segment owing to high resource potential and land availability. They are either owned by the consumer directly or by a third-party developer in distant location, who "wheels" the electricity across the grid to consumer sites while taking advantage of the net-metering scheme. Faster growth in the region is challenged by regulatory barriers that prevent timely grid connections, the lack of a framework for remunerating excess generation in countries outside those aforementioned, and subsidised electricity rates. Expansion could be twice as high if these barriers were removed and electricity tariffs became more cost-reflective, improving economic attractiveness.

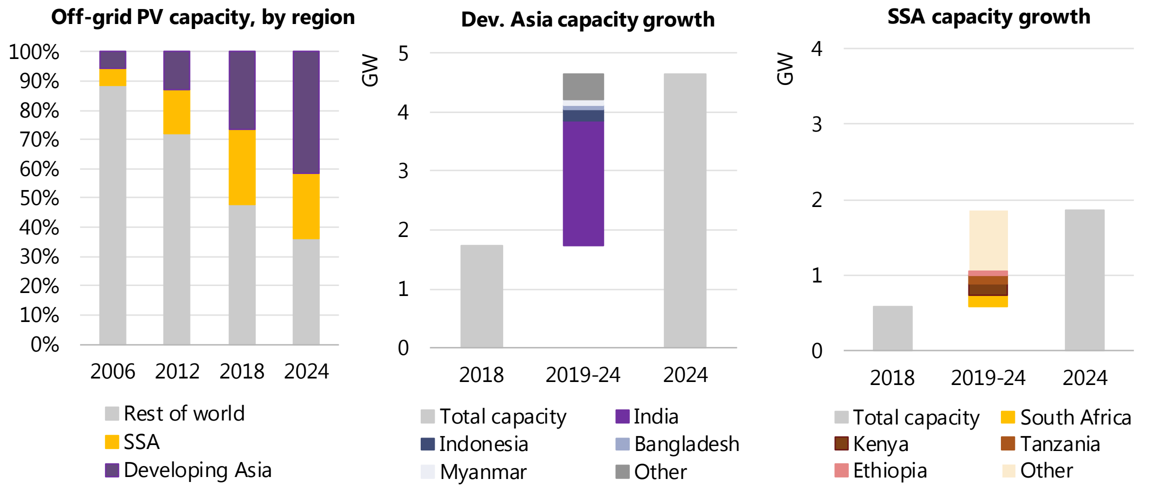
Off-grid solar PV

For the first time in history, in 2017 the number of people living without access to electricity dropped to below 1 billion. While the electrification rate in developing Asia has reached 90%, more than half of the sub-Saharan population does not have electricity access. While grid extensions continue to be pivotal to provide universal electrification, off-grid applications are the least-cost solution to bridge the electrification gap (IEA, 2018).

Historically, in 2006, due to high solar PV costs, nearly all off-grid capacity was located in China for electrification, and in Europe, North America and Australia for providing power in remote areas. However, rapid cost reductions of both modules and battery storage have shifted the off-grid market to sub-Saharan Africa and developing Asia, which together accounted for half of global off-grid solar PV capacity (2 GW) in 2018 (Figure 2.25).

Renewables 2019 forecasts a doubling of global off-grid capacity to over 9 GW in 2024, with developing Asia responsible for most of this growth, led by India as a result of its grant programmes. Nevertheless, off-grid PV is expected to represent less than 5% of Developing Asia's total solar capacity by 2024, as grid-connected PV applications expand much more quickly owing to relatively high electrification rates and better-developed grid networks able to accommodate on-grid additions (Figure 2.25). Meanwhile, in sub-Saharan Africa, off-grid installations represent around 20% of total PV capacity by 2024 as off-grid applications provide initial electricity access in regions with limited grid networks.

Figure 2.25 Shares of solar off-grid capacities installed and capacity additions by region



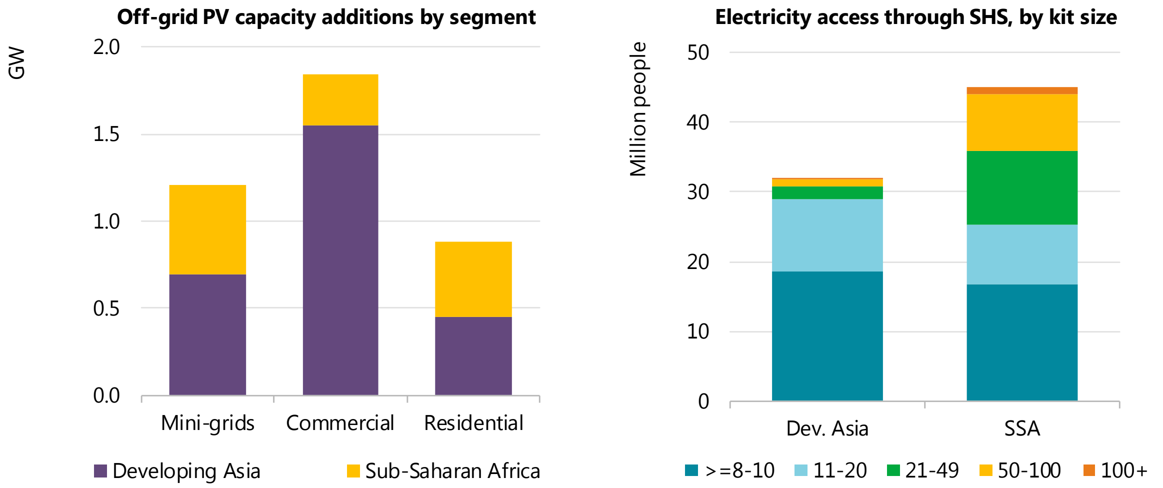
Note: SSA = sub-Saharan Africa.

In **developing Asia**, growth is driven by countries working towards universal electrification and backed by ambitious targets and policies (Figure 2.26). **India** is expected to dominate growth, as the country is nearing full electrification by extending its national grid and supporting off-grid solutions for commercial applications. Towards the end of 2018, India adopted the KUSUM policy to provide capital grants for stand-alone solar water pumps, prompting the *Renewables 2019* commercial off-grid forecast. **Bangladesh** aims to install 50 000 solar water pumps by 2025, contributing to important off-grid growth in the region, and Bangladesh, Indonesia and the Philippines support off-grid mini-grids by making affordable financing more accessible and by amending relevant regulations to reduce reliance on expensive diesel generators. Additionally, the Philippines aims to distribute 40 000 solar home systems (SHSs) by 2022, and in **Nepal** international aid organisations are assisting in the construction of several mini-grids.

In **sub-Saharan Africa**, countries are working on raising electrification rates, with several having concrete policies and financing platforms in place for off-grid PV expansion; however, private sector support is pivotal for off-grid PV expansion in the region. **Kenya** is a regional leader in off-grid business innovation and development: home to various private companies working on new business models and expanding their offers, Kenya leads SHS sales by volume in Africa, adding an estimated 11 MW in 2018 and an anticipated 120 MW more during 2019-24. To provide additional support for electrification, Kenya's Ministry of Energy launched the Off-Grid Solar Access Project (KOSAP) in 2019, financed and structured by the World Bank. The programme is designed to provide financing to private companies working on SHS kits, mini-grids and solar water pump installations.

Tanzania is another country with a strong SHS market. Off-grid applications for the residential sector are forecast to dominate off-grid growth, adding an estimated 110 MW of capacity. For mini-grid deployment, South Africa and Nigeria lead regional growth. In **South Africa**, the mining industry is investing in mini-grids to replace expensive diesel-fired generators, avoiding fuel delivery challenges in remote areas. **Nigeria** adopted detailed legislation regulating mini-grid licensing and tariffs as well as measures to reduce investor risks when grid access becomes available. With the support of international donors and financing institutions enabling access to additional financing, the mini-grid sector is expected to take off in both countries.

Figure 2.26 Off-grid PV additions by segment, and additional initial access by SHS kit size and region, 2019-24



In developing Asia, off-grid applications for the **commercial and industrial segment** lead growth as a result of policy adoptions in several countries that incentivise solar water pump uptake. In sub-Saharan Africa, off-grid expansion is evenly distributed among the three segments – **mini-grids, commercial and industrial**, and **SHS kits for residential use** – as countries in the region adopt a blend of policies, are aided by international financing institutions and receive increasing private sector support.

The **residential segment** is expected to provide initial electricity services to 32 million people in the developing Asia region over the next five years, mostly from smaller kits, as Pay As You GO (PAYGO) system sales have not yet expanded into this region. In sub-Saharan Africa, SHSs are expected to improve energy access for around 45 million people, as bundles from a higher range of sizes are gaining popularity.

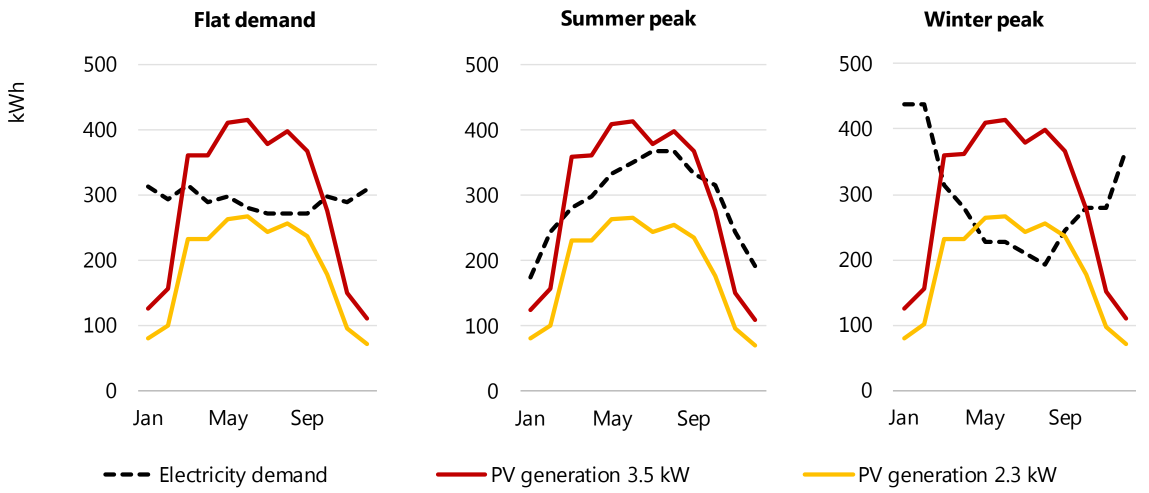
SHS kits can be purchased in one full payment by cash or through the PAYGO system, whereby clients pay an initial subscription fee and follow up with further instalments. The payment duration ranges from five months for 30-W to 60-W units, to a maximum of five years for 80-W packages. SHSs purchased through the PAYGO model are 25-40% more expensive than kits purchased in one installation, but the loan system enables initial electricity service access for clients with modest home budgets, who otherwise would not be able to afford the system.

Implications for policy making

Distributed solar PV expansion, driven by rapid cost reductions and policy support, is transforming electricity markets. Because the speedy adoption of residential, commercial and industrial PV systems is blurring the roles of electricity producers and consumers in many countries, this trend deserves careful attention from policy makers.

Poorly managed and over-hasty deployment, spurred by the economic attractiveness of distributed solar PV in comparison with retail electricity tariffs for private consumers, creates a number of concerns. They stem mainly from the time mismatch between PV output and electricity demand, particularly for household consumers in temperate countries whose peak demand is in the evening in winter. The supply-demand match is better in sunny countries, where peak demand occurs in the summer due to higher electricity consumption for air conditioning (Figure 2.27). PV output and demand are also better synchronised for commercial customers owing to higher daytime consumption.

Figure 2.27 Monthly generic (northern hemisphere) load profiles and PV generation



The first – and likely most important – concern is related to the fair allocation of fixed costs, notably distribution grid costs. Distributed PV will reduce grid costs only where local consumption of PV electricity implies a reduction in peak power loads. Even in sunny countries, air conditioning peak demand tends to be in the late afternoon or evening. Therefore, without affordable storage or the use of demand-side response, PV deployment is unlikely to reduce distribution grid costs.

At the same time, unless retail tariffs are restructured to account for distributed PV deployment, more distributed PV generation means less income for distribution and retail companies because PV owners purchase fewer kWh. In most countries, fixed grid costs are covered primarily by variable tariff charges, which has two consequences: 1) it increases financial pressure on distribution companies, which are in a very delicate position, as they are also centralised renewable electricity off-takers in many countries; and 2) it can ultimately raise retail electricity prices, as the same costs need to be allocated on a lower amount of kWh; this clearly raises a question of fairness between PV and non-PV owners.

Electricity tariffs usually also include other components such as taxes and levies, including FIT surcharges. Wider distributed PV deployment therefore means forgone renewable energy surcharges as well as other charges and taxes levied on a per-kWh basis, which will need to be recovered from other consumers. This can lead to the peculiar situation in which the customers who avoided paying for past PV cost reductions are precisely those reaping the benefits of the reductions. More distributed PV can also lead to forgone tax revenues for both local and central governments.

All these issues are particularly evident in countries employing net metering with annual energy accounting. Such an incentive scheme does not foster self-consumption and tends to encourage excess PV generation at times when there is no demand, remunerating it at a retail electricity price that often exceeds the value that PV production provides to the power system.

Policy makers will need to address these issues carefully in the future to balance the interests of all stakeholders.

PV owners

Small-scale solar PV generation costs are currently lower than the variable part of retail tariffs in many countries in the world where electricity prices are not subsidised. This trend continues over the forecast period even if retail prices remain at current levels, as residential and commercial solar PV costs are expected to decline further. Supported by policy schemes, consumers are seeking opportunities to save on their electricity bills and to investment in projects with reasonable payback periods, so low interest rates in many developed and some developing countries facilitate the adoption of distributed PV systems.

Depending on the length of net-metering accounting periods, surplus electricity export limits and system size, PV owners could reduce their electricity bills by up to 95% (ratepayers still have to pay monthly fixed charges). At today's electricity prices and assuming a 25-75% contractual self-consumption rate, PV owners in Japan could save USD 15 billion over the forecast period, and those in Germany USD 45 billion. In Australia, despite significant penetration of large residential systems, savings are relatively smaller because fixed charges account for only 30-35% of the electricity bill. In California, PV owners can achieve relatively higher savings through annual net metering and by having larger residential systems.

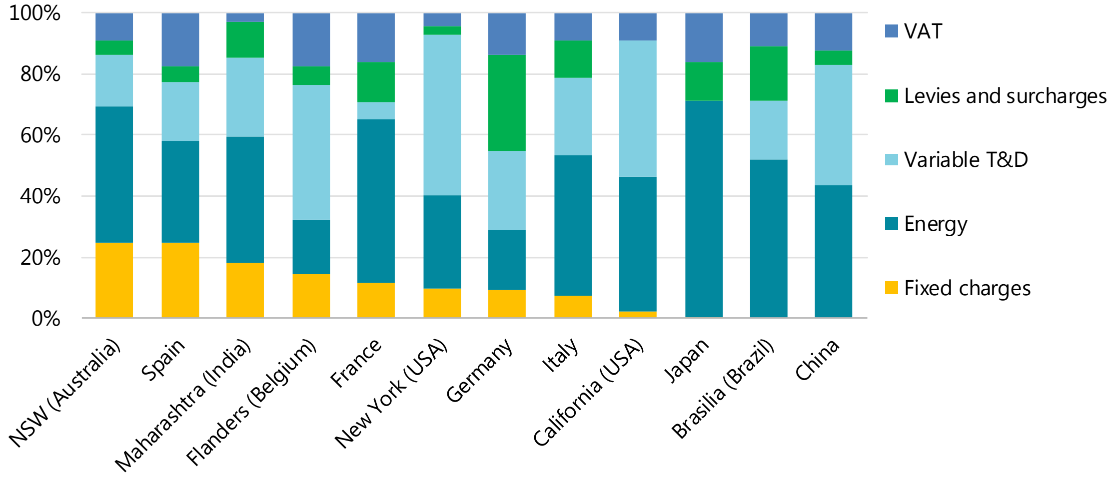
Electricity consumers in many countries are increasingly exposed to different electricity pricing schemes (time-of-use, on- and off-peak, two-part, etc.). In liberalised retail electricity markets, consumers can choose from a variety of suppliers based on what they are offering. In many countries, retailers include a PV system or energy efficiency services in their electricity offers, promising further bill savings. While being able to choose from among various pricing schemes can give consumers with distributed PV more control over their electricity production and consumption, they will be exposed to more complicated choices concerning investment returns as they switch from being pure consumers to producers of electricity. Thus, regulatory and retail price changes will have a stronger direct impact on PV owners than on pure consumers.

Retail price design matters for all stakeholders

Retail price design varies significantly by country and state/province. Knowing the exact share of each of the various rate components is important not only for assessing the economic attractiveness of distributed solar PV applications, but for utilities and governments to determine charges for electricity T&D, special levies and surcharges (including those for renewables, nuclear decommissioning, district heating infrastructure, etc.), and finally VAT.

Consumers are obligated to pay the fixed component of their electricity bill every month, regardless of their consumption. In many countries, fixed charges account for 3-15% of average residential electricity bills (Figure 2.28), usually covering monthly subscription, service and meter fees. In Spain as well as some Australian states and Canadian provinces, as much as 25-35% of the electricity bill can be fixed costs because some or most of the T&D charges are included. For consumers with PV systems, having a higher fixed component to the electricity bill means lower savings, but considering T&D charges as a fixed cost also means that distribution company revenues are less affected by wider PV self-consumption.

Figure 2.28 Residential electricity price structures of selected countries, 2018-19



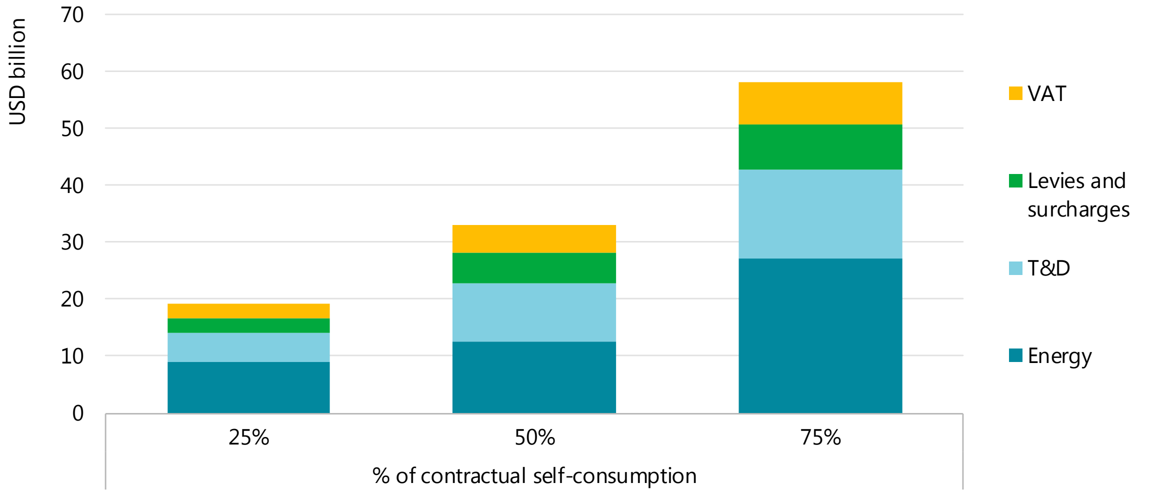
Theoretically, the self-consumption of electricity normally benefits both the consumer and the system when there is a good match between PV generation and demand. Consumers save the most on their electricity bills by maximising self-consumption while reducing the system's peak demand, avoiding additional generation and distribution investments.

In practice, however, the situation is much more complex. First, residential and commercial system expansion in one single distribution area may require additional investments to upgrade the distribution grid. Second, maximising self-consumption means decreasing revenues for the grid, as T&D costs are charged on a volumetric basis (per kWh) in many countries.

Variable or volumetric T&D charges account for 25-40% of retail electricity prices in many countries, with the distribution network usually representing a significant majority (70-90%) of these costs. Therefore, under volumetric retail pricing, higher PV self-consumption (real-time and contractual) results in less revenue for the distribution grid – even though PV owners still rely on the grid for their peak consumption and other grid services when the sun is not shining. Thus, grid maintenance costs remain the same, or possibly even rise because transformers need to be adapted to work both ways and, more importantly, some sections may have to be reinforced to transport higher fluxes. In addition to being responsible for maintenance, distribution companies also have the usual distribution system operator (DSO) obligations to the public (covering supplies for users with financial issues, providing renewable energy subsidies, overseeing public lighting, conducting R&D, etc.) even though their revenues are in rapid decline. This raises concerns over the fair sharing of grid costs between PV and non-PV consumers, as non-PV owners under a variable to heavy retail pricing schemes may be paying higher grid costs.

At current retail prices, distribution companies' annual variable grid revenue losses could reach over USD 15 billion (assuming 75% contractual self-consumption) by 2024 (Figure 2.29) – almost triple their losses in 2018 – and cumulative global T&D revenue losses could be up to USD 70 billion in the next six years, almost one-quarter of all T&D investment worldwide in 2018

Figure 2.29 Estimated annual revenue losses from distributed PV on different contractual self-consumption assumptions, 2024



Revenue losses due to contractual self-consumption can go beyond regulated distribution companies responsible for grid infrastructure. As the energy component is expected to account for 35-45% of total revenue losses, depending on contractual self-consumption assumptions, retailers could lose up to USD 28 billion annually by 2024 on energy sales, affecting their revenues. As a result, electricity generators will also sell less energy to retailers as self-consumption increases. In some cases, this impact could be moderated by avoiding additional investment in new generation capacity.

Government revenues are also affected: levies and surcharges, which include special electricity taxes, renewable energy and/or fossil fuel subsidies, nuclear decommissioning fees and other infrastructure costs, are also charged on a volumetric basis and will thus be reduced with increasing penetration of distributed PV. Taken together, value-added taxes, levies and surcharges could represent another 25-30% of total revenue losses, which would negatively affect government budgets worldwide.

Sustainable distributed PV deployment therefore depends on sound market design as well as policy and regulatory frameworks that balance the opposing interests of distributed PV investors, system operators, distribution companies and other (non-PV) electricity consumers. Tariff reforms and appropriate policies will be needed to attract investment in distributed solar PV while also securing enough revenues to pay for fixed network assets and ensuring that the cost burden is allocated fairly among all consumers.

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3. Transport biofuels

Highlights

- **Global biofuel production increased 10 billion litres (L) in 2018 to reach a record 154 billion L.** Double the growth of 2017, this 7% year-on year (y-o-y) increase was the highest in five years. Ethanol output expanded 6.6 billion L (6% y-o-y), mostly owing to significantly higher production in Brazil, and combined biodiesel and hydrotreated vegetable oil (HVO) output increased 3.6 billion L (9% y-o-y), with over half of this growth in the United States.
- **Biofuel output is anticipated to increase 25% during 2019-24**, to reach 190 billion L, with the forecast revised upwards from last year owing to better market prospects in Brazil, the United States and especially the People's Republic of China ("China"), which boasts the largest increase of any country. Asia accounts for half of growth, as the promise of using conventional biofuels to diversify transport fuel supplies and boost demand for agricultural commodities has resulted in ambitious biofuel mandates.
- **China leads forecast ethanol production growth, with output more than tripling to 11 billion L.** Concrete measures are being taken to raise ethanol consumption from around 2% to the target of 10% of national gasoline demand. Ethanol blending programmes are being expanded from 11 to 15 provinces, and production capacity is set to increase almost 50% by 2021 alone. Domestic output, however, is still expected to fall short of the ambitious target by 2024.
- **HVO production is set to more than double from around 5.5 billion L in 2018 to 13 billion L in 2024.** EU and US policy-driven demand spurs investments of USD 5 billion (United States dollars) in new projects, with most facilities planning to use waste and residue feedstocks. As a result, HVO accounts for one-fifth of forecast biofuel output growth. Most facilities plan to utilise waste and residue feedstocks, making HVO the largest source of advanced biofuel production growth over the forecast period. A number of plants will also produce aviation biofuels.
- **Around 9% of biofuels produced in 2018 were advanced**, with 13.5 billion L made from non-crop-based wastes and residue feedstocks – mostly biodiesel and HVO made from waste fats, oils and grease (FOG). A much smaller portion of advanced biofuels were produced by less mature technologies that use lower-cost, higher-availability feedstocks, as the high risk of investing in commercial-scale refineries that employ first-of-a-kind technologies hampers growth.
- **In the main case, renewable energy meets just 4.6% of transport fuel demand by 2024**, as most biofuel mandates require blending levels of only 10% or less (policies in Brazil, Indonesia and Thailand that target higher consumption are notable exceptions). Vehicle testing, greater use of "drop-in" fuels,[8] and frameworks that ensure biofuel sustainability are required to encourage higher biofuel blending levels. Electromobility's contribution also grows in importance, with renewable electricity providing 10% of renewable energy in transport by 2024.
- **The accelerated case demonstrates that biofuel output could increase a further 20% to 225 billion L by 2024** with more favourable market conditions and policies. Ethanol output could be 25 billion L higher than in the main case, with most additional production in China, India and the United States. Biodiesel and HVO output could rise a further 12.5 billion L, primarily in Brazil, the European Union and the United States.

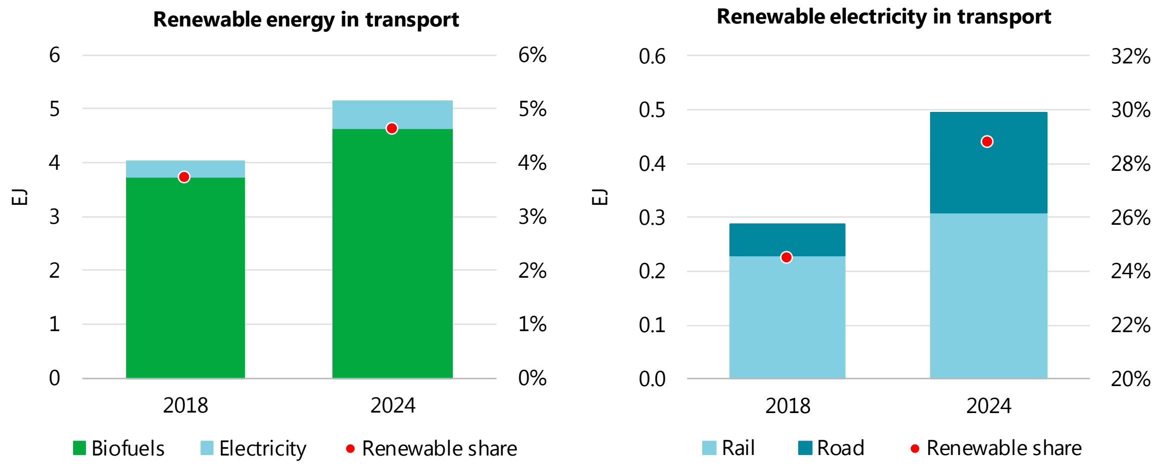
[8] Suitable for use at high blend shares, or unblended without technical modifications to engines or to fuelling infrastructure.

Renewable transport overview

Renewable energy met around 3.7% of transport fuel demand in 2018, with around 4 exajoules (EJ) of consumption (Figure 3.1). Biofuels provided 93% of all renewable energy, the remainder being renewable electricity. Biofuel output expands 24% (0.9 EJ) over 2019-24, while renewable electricity in transport is anticipated to increase 70% (0.2 EJ) with greater use of electrified rail as well as electric vehicles, combined with higher shares of renewables in electricity generation.

By 2024, the renewable energy share of transport demand increases only marginally to 4.6% (5.1 EJ). This increase is relatively small because transport fossil fuel demand also climbs 3% (3 EJ) with higher consumption in Asia, where vehicle ownership is on the rise being a key factor. The biofuel share of renewable energy in transport in 2024 decreases slightly to 90%.

Figure 3.1. Renewable energy and electricity in transport 2018, and forecast for 2024



Note: Electric vehicles have two to three times better fuel economy than internal combustion engine vehicles, which contributes to lower renewable energy consumption compared with biofuels.

Source: IEA (2019c), "Modelling of the transport sector in the Mobility Model".

Global biofuel production rose 7% in 2018 to reach 154 billion L. The forecast has been revised upwards since *Renewables 2018*, with output expected to increase by one-quarter to 190 billion L over the forecast period. This upward revision is primarily a result of improved market prospects in the United States, China and Brazil. Under the more favourable market conditions and policies of the accelerated case, global production could reach 225 billion L in 2024, a 20% increase from the main case.

Renewable electricity in transport increased 11% y-o-y in 2018 to reach just under 0.3 EJ; by 2024, consumption increases to 0.5 EJ, equating to a renewable share of 29% in electrified transport. China accounts for over 60% of renewable electricity used for transportation, shared roughly equally by road and rail. By the end of the forecast period, road transport consumes more renewable electricity than rail in the United States, but still less than rail in Brazil, India, Japan and the European Union. Therefore, rail is anticipated to be responsible for just under two-thirds of transport sector renewable electricity demand globally in 2024, even though the global electric car fleet expands from 5 million in 2018 to around 40 million by the end of the forecast period.

Global biofuel markets overview

China boasts the largest biofuel output growth of any country, which is the main reason that Asia provides half of production growth in the main case (Table 3.1). In Asian countries, rising road transport fuel demand, combined with new policy initiatives, stimulates increased biofuel production. These countries are increasingly adopting mandates for the consumption of domestically produced biofuels because of their potential to reinforce energy security while boosting demand for agricultural commodities and improving air quality (IEA, 2018).

Table 3.1. Global biofuel production

Billion L	2018	2019	2020	2021	2022	2023	2024	Share of production 2024	Share of growth 2019-24
North America	71.0	71.5	72.5	75.5	77.0	77.5	77.5	41%	19%
Latin America	43.0	43.5	44.5	46.5	47.5	49.5	51.5	27%	23%
Europe	20.5	21.0	23.0	22.0	21.5	21.0	21.5	11%	3%
Asia	16.5	19.5	22.0	26.0	30.5	32.0	35.0	20%	53%
Rest of world	1.5	2.0	2.0	2.5	2.5	2.5	2.5	1%	2%
Total	**152.5**	**157.5**	**164.0**	**172.0**	**178.5**	**182.5**	**187.5**	**100%**	**100%**

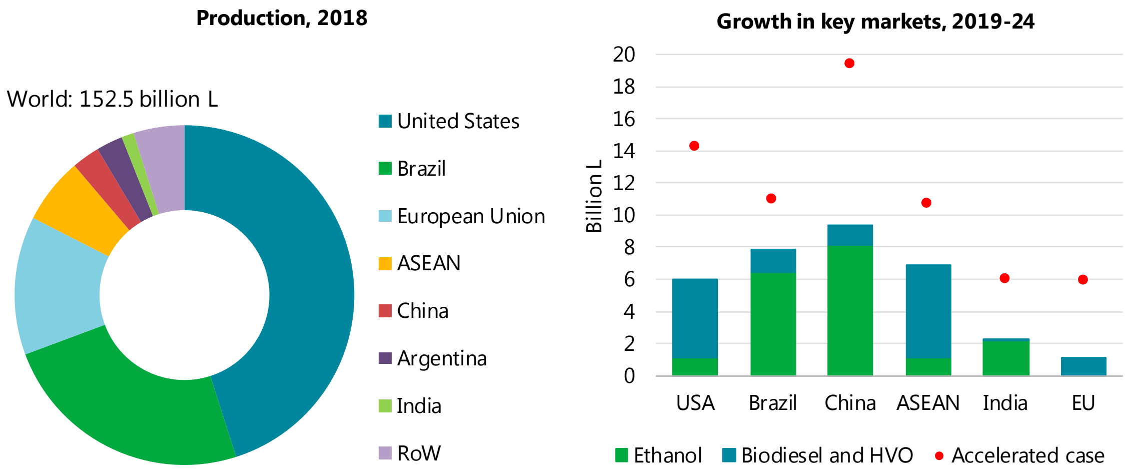
Notes: Includes ethanol, biodiesel and HVO production but excludes "novel advanced biofuels" as defined in Table 3.7. Rounded to the nearest 0.5 billion L. Europe refers to OECD Europe. Latin America excludes Mexico, which is covered under North America.

Sources: IEA (2019a), *Monthly Oil Data Service (MODS)*, May 2019, www.iea.org/statistics/; IEA (2019b), *Oil Information* (database), www.iea.org/statistics/; MAPA (2019), Produção, www.agricultura.gov.br/assuntos/sustentabilidade/agroenergia/producao; US EIA (2019), *Petroleum and Other Liquids*, www.eia.gov/petroleum/data.cfm.

The United States and Brazil were the largest biofuel producers in 2018 (Figure 3.2). Together they account for 40% of forecast biofuel output growth over 2019-24, providing two-thirds of main case production in 2024. The United States leads in total production of ethanol as well as biodiesel[9] and HVO by 2024, and Brazil ranks second for ethanol and third for biodiesel and HVO.

[9] Throughout this chapter, "ethanol" refers to fuel ethanol only; "biodiesel" refers to fatty acid methyl ester (FAME) biodiesel.

Figure 3.2. Biofuel forecast overview



Notes: ASEAN = Association of Southeast Asian Nations. RoW = rest of world. Includes ethanol, biodiesel and HVO production but excludes "novel advanced biofuels".

Sources: IEA (2019a), *Monthly Oil Data Service (MODS)*, May 2019, www.iea.org/statistics/; IEA (2019b), *Oil Information* (database), www.iea.org/statistics/; MAPA (2019), Produção, www.agricultura.gov.br/assuntos/sustentabilidade/agroenergia/producao; US EIA (2019), *Petroleum and Other Liquids*, www.eia.gov/petroleum/data.cfm.

Modest (5%) conventional biofuel production growth is anticipated in the European Union during 2019-24. The updated Renewable Energy Directive (RED) for the post-2020 period introduces a target of 14% renewable energy in transport by 2030, with a maximum contribution of 7% from conventional biofuels. In addition, member states may increase the contribution of conventional biofuels to renewable energy in transport by up to only 1 percentage point from the 2020 level. Strengthened policy support for conventional biofuels is therefore not expected after 2020 in the main case. Furthermore, lower anticipated demand for gasoline (-2%) and diesel (-10%) during 2019-24 will reduce the biofuel demand created by existing mandates, and ethanol and biodiesel production will consequently fall slightly.

Ethanol markets: Regional forecast

Fuel ethanol production expanded 6% y-o-y in 2018, to 110 billion L globally; almost 60% of this increase resulted from record production in Brazil. Global output is anticipated to increase almost 20% over the forecast period, to 130 billion L by 2024.

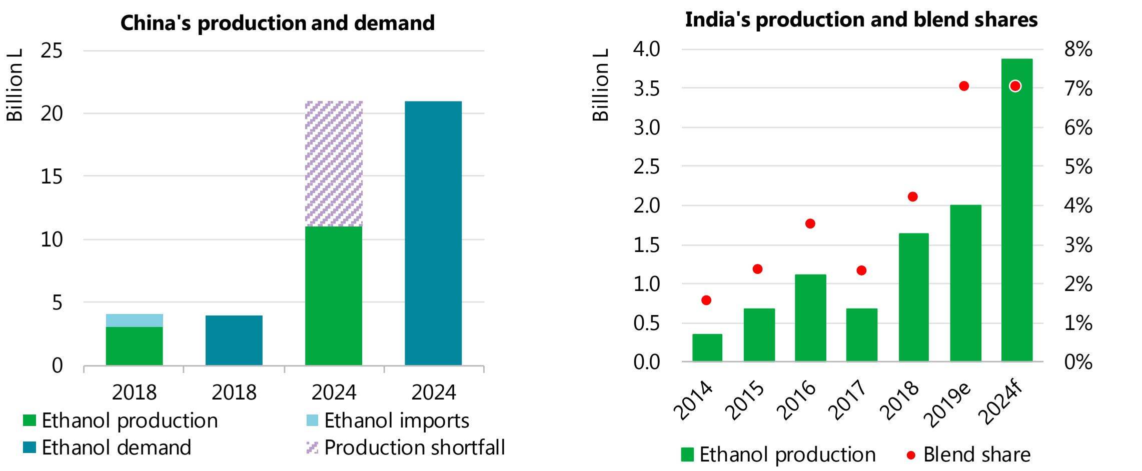
China is expected to lead global ethanol production growth (Figure 3.2). In 2018, fuel ethanol production was around 3 billion L, and output is forecast to more than triple to 11 billion L by 2024 – a significant upward revision from last year's forecast. Ethanol consumption currently satisfies around 2% of gasoline demand. However, offsetting a larger portion of crude oil imports through higher ethanol consumption is the principal motivation behind plans to roll out E10 ethanol blends nationwide.

Concrete developments to meet this aim are beginning to take shape: the expansion of fuel ethanol consumption from 11 to 15 provinces is already under way, with coastal areas leading the transition to E10. Plus, the E10 supply programme has been introduced in Guangdong, the area of China that consumes the most gasoline, with plans announced for Guanxi and Shandong provinces. Tianjin has also begun to supply E10 to consumers.

A number of new facilities are under construction to meet this higher demand, with production capacity increasing by close to 50% (to over 7 billion L) over the next two years and further plants in development. The main feedstock for ethanol production is corn, but some is from cassava.

Nevertheless, domestic ethanol output is anticipated to reach only just over half the level required to meet 10% of nationwide demand during the forecast period (Figure 3.3), which, considering average annual gasoline demand growth of 3% per year, equates to around 21 billion L by 2024. Delivering forecast growth will require greater consumer recognition and acceptance from blenders of E10. Although ethanol imports reached record levels in 2018, the eligibility of imports to make up the anticipated shortfall in demand in 2024 is unclear.

Figure 3.3. China and India forecast summary



Notes: "Production shortfall" refers to the difference between forecast 2024 production and demand, based on nationwide E10 introduction. 2019e = 2019 estimate; 2024f = 2024 forecast. Production data for India are for the annual calendar year, while blend shares are for December to November.

Source: F.O. Lichts (2019), India fuel ethanol blending hits record level.

Ethanol output in **India** rebounded in 2018 to a record 1.6 billion L. Higher output resulted from favourable weather conditions and a large supply of molasses feedstocks, as well as higher oil prices, which boosted ethanol demand from national oil marketing companies. Ethanol blending surpassed 4% in 2018 and is expected to meet the national 5% blending mandate[10] for the first time in 2019. Judging by year-to-date blending, consumption could reach 7% (Figure 3.3).

Production is anticipated to more than double to 3.9 billion L by 2024, an upward revision from last year's forecast, as long-term drivers for ethanol industry expansion are strong. India has an indicative blending target of 20% by 2030 (comprising conventional and cellulosic ethanol), but a shift in the vehicle fleet to accommodate this higher ethanol share is needed to meet the goal.

[10] A 10% blending target is in place for the major ethanol-producing states.

With gasoline demand anticipated to expand one-third during 2019-24, using domestically produced ethanol is a means to offset oil demand, in line with the challenging aim of reducing crude oil imports 10% by 2022. In addition, ethanol production supports the national sugar industry, as product diversification is particularly important when sugar prices are low.

Measures from India's 2018 national biofuels policy are also being enacted. Ethanol production capacity is expected to expand significantly with the approval of subsidised government loans for nearly 120 greenfield and brownfield projects at sugar mills and other sites. Furthermore, whereas previous regulations allowed only molasses from the sugar industry to be used for ethanol production, the new policy widens the range of permitted feedstocks, with production from sugar cane juice and damaged food grains already in progress. Interstate taxation issues that hampered the movement of ethanol across state boundaries have also been addressed.

Ethanol output in **Brazil** increased almost 15% y-o-y in 2018, to a record 31.8 billion L (Figure 3.4) owing to two key factors. First, recent investments in ethanol equipment and storage made it possible for sugar mills to switch more flexibly from sugar to ethanol production based on profitability. Consequently, with international sugar prices being low in 2018, mills maximised ethanol production at the expense of sugar.

Second, there was higher domestic demand for unblended hydrous ethanol for the country's large flexible-fuel vehicle (FFV) fleet, as fiscal incentives, the weak Brazilian real and higher oil prices during much of the year made it more price-competitive with gasoline.

Ethanol production is anticipated to increase by 20% to around 38 billion L by 2024. The introduction of the Renovabio scheme in 2020 (Box 3.1) will provide an additional income stream for producers in the form of tradable emissions reduction certificates.

This is expected to improve the economics of biofuel production and in turn support fuel ethanol production capacity expansion through the enlargement of existing sugar mills and the reinstatement of idle ones, as well as greenfield investments. This is especially important given the poor financial health of many mills, as should a significant number of active mills fall out of production the amount of growth expected in the forecast would reduce.

Box 3.1. How will Brazil's RenovaBio policy work?

Brazil will introduce RenovaBio, its flagship biofuels policy, in 2020. It is the core policy to increase the share of sustainable biofuels in Brazil's energy mix to 18% by 2030, as outlined in its Nationally Determined Contribution (NDC) under the United Nations Framework Convention on Climate Change (UNFCCC) Paris Agreement. RenovaBio will help Brazil achieve this target by providing a framework to raise demand for biofuels (e.g. ethanol, biodiesel, biojet fuel and biomethane) and make their production more profitable.

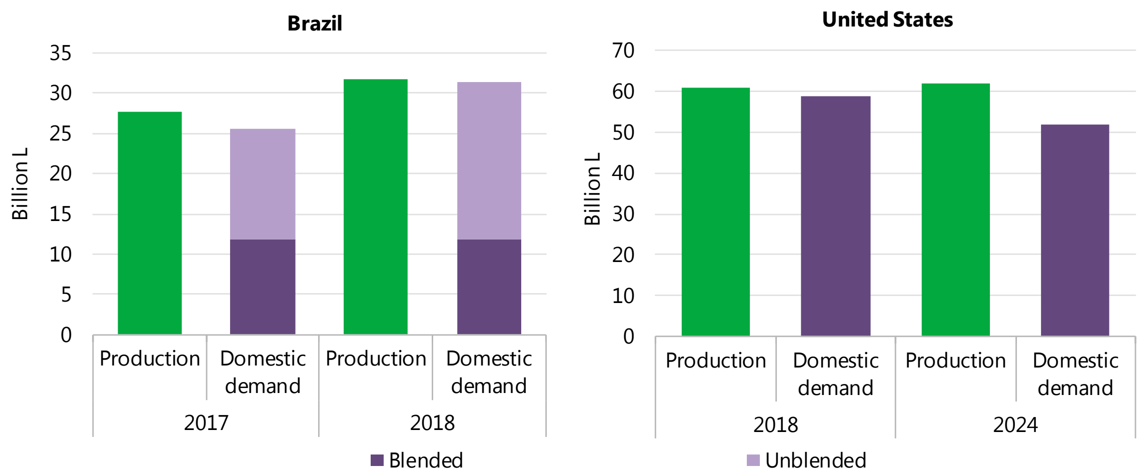
The National Energy Policy Council (CNPE) established the target to reduce transport fuel carbon intensity 10% by 2028. To achieve this reduction, the National Agency of Petroleum, Natural Gas and Biofuels (ANP) will set annual targets for individual fuel distributors based on their fossil fuel market shares. To meet these targets, fuel distributors will need to acquire decarbonisation certificates (called CBIOs), each of which is equal to 1 tonne of mitigated carbon dioxide (CO_2). The ANP can impose penalties such as fines or alternative sanctions on non-compliant fuel distributors.

The carbon intensity of biofuels from participating producers will be established through third-party certification using a standardised methodology (RenovaCalc). This will in turn determine the emissions reduction offered by the biofuel in comparison with a fossil fuel benchmark. The volume of biofuels sold, multiplied by the assessed lifecycle carbon intensity of the fuel, determines the number of CBIOs to be issued to a certified biofuel producer.

The trading of CBIOs through a stock exchange could provide not only an additional revenue stream for biofuel producers, but a platform through which fuel distributors may obtain the CBIOs they need to meet their obligations. Although producer participation in the programme is voluntary, non-participation will make them ineligible for the additional revenue from producing CBIO certificates. The programme also covers imported biofuels and is firmly committed to ensuring that no deforestation occurs.

An expansion of corn ethanol production also supports forecast output growth, with a number of plants in development. Several factors encourage investment in this area: 1) low set-up and competitive production costs; 2) the prospect of additional revenue from the production of dry distillers' grains, a valuable feed source for Brazil's cattle herds; and 3) corn's short agricultural cycle compared with sugar cane, which means a faster scale-up of feedstock availability.

Figure 3.4. Ethanol production and demand overview



Source: UNICA (2019), *UNICA Data* (database), www.unicadata.com.br.

In the United States, ethanol production rose by around 1.7% y-o-y to 60.1 billion L in 2018, with continued high capacity utilisation by facilities. Output is forecast to stabilise at this level, with 62 billion L anticipated in 2024 – almost 50% of global production. The Renewable Fuel

Standard (RFS2)[11] is the key federal policy mechanism supporting US biofuel consumption, and corn ethanol has now reached its statutory limit under the policy.

Blending gasoline with 10% ethanol (known as E10) is standard practice. However, the increasing efficiency of the vehicle fleet is expected to result in a 4% contraction in gasoline demand over the forecast period, consequently reducing domestic ethanol consumption (Figure 3.4).

Nevertheless, increased exports are expected to keep production stable as domestic demand falls. In 2018, the United States sustained its three-year trend of expanding fuel ethanol exports, with over 6 billion L supplied to Brazil, Canada, India and other countries. However, maintaining the export growth needed to offset lower US demand will require the opening-up of new markets, especially in Asia. Prospects for exports to the European Union have also widened with the withdrawal of anti-dumping duties in 2019, but US ethanol must still meet the greenhouse gas (GHG) emissions reduction requirements of the EU market.

Higher consumption of E15[12] ethanol blends has a lower impact on the forecast. Although regulation reforms permitting year-round E15 sales make supplying it more attractive for service stations,[13] only around 1% of them stock the blend nationally, and expanding supplies to the approximately 20 states where E15 is not currently available will take time. The US Environmental Protection Agency has issued a waiver permitting E15 use in cars of model year 2001 or newer, so vehicle suitability should be less of a constraint on increased E15 consumption than fuel distribution infrastructure.

E15's price competitiveness with E10 at the pump will also affect demand, with the break-even crude oil price for ethanol production in the United States at USD 65-75 per barrel (bbl). Consumption of E85 also makes a modest contribution to the forecast, with around 4 500 service stations currently offering the blend.

Table 3.2. Annual production in other key ethanol markets (billion L)

Country/region	2018 output	2024 output	Forecast revision	Forecast overview
European Union	5.2	5.1	▲	Stable gasoline demand; stronger policy support post-2020 not anticipated; anti-dumping duties on US ethanol repealed; growing E10 demand in France.
Canada	1.9	2.0	►	4% reduction in gasoline demand; Ontario mandates increase to E10 in 2020; federal Clean Fuel Standard regulations for liquid fuels in place by 2022.
Thailand	1.5	2.2	▲	Gasoline demand up 13%; new capacity coming online; fiscal incentives for FFVs; E20/E85 blends subsidised; long-term target to 2036.
Argentina	1.1	1.3	►	17% increase in gasoline demand; 12% mandate in place; proposed mandate increase not in forecast; production from both sugar cane and corn.

Note: Up arrow indicates forecast revised upwards from last year, down arrow indicates forecast revised downwards, and right arrow indicates forecast has remained stable.

[11] The RFS2 runs until 2022; however, because of the policy's importance to the agriculture sector and ethanol's octane value, IEA biofuel forecasts assume that the policy remains in place throughout the forecast period.
[12] Gasoline blended with 15% fuel ethanol by volume. E85 refers to gasoline blended with up to 85% fuel ethanol by volume.
[13] E15 requires separate storage and pump infrastructure from E10.

Biodiesel and HVO markets: Regional forecast

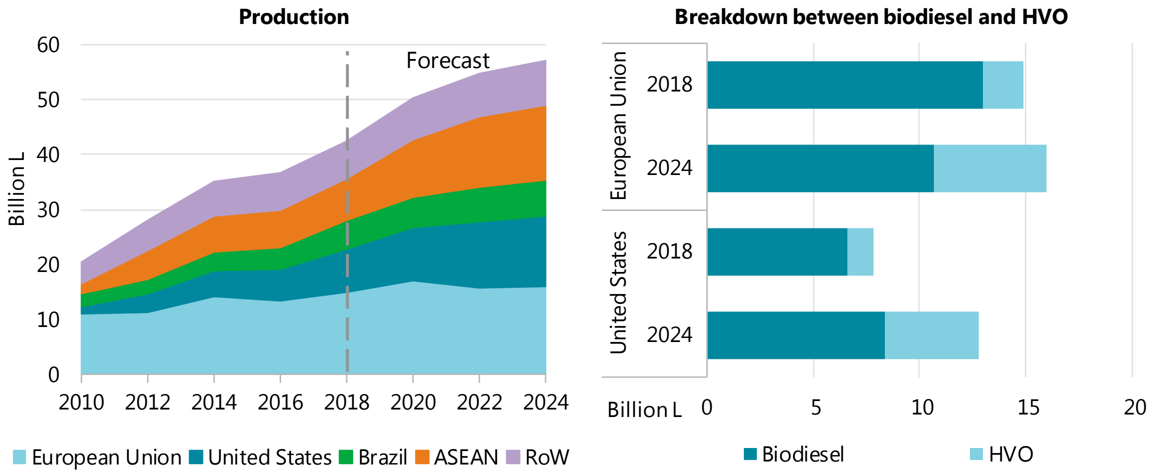
Biodiesel and HVO production rose 9% from 2017 to 2018, reaching 43 billion L. Production is forecast to expand one-third, to around 57 billion L in 2024.

With output of 14.9 billion L, biodiesel and HVO production in the **European Union** decreased 2% in 2018. France, Germany, Spain and the Netherlands combined were responsible for two-thirds of total production. The removal of anti-dumping duties on biodiesel imports from Argentina and Indonesia, and the subsequent reestablishment of shipments, caused imports to increase threefold y-o-y. This constrained output of the least competitive European biodiesel producers.

Production is anticipated to increase 15% (17 billion L) by 2020 as a result of progressively higher biofuel mandates in various member states. For example, in France, Italy, Poland and Spain, mandates will be increased in an effort to meet the RED 2020 target of 10% renewable energy in transport. According to the latest data (for 2017), Finland and Sweden have already exceeded the 10% target, while Austria and France have achieved over 9% renewable energy in transport.

After 2020, output gradually declines to 16 billion L in 2024. Fewer diesel car registrations (only 36% of EU passenger car registrations were diesel in 2018) and the increasing efficiency of the vehicle fleet means diesel consumption drops 10% over the forecast period. This consequently reduces biodiesel and HVO demand created by mandate policies, but HVO facilities coming online in France, Italy and some Nordic countries offset the impact of this reduction on forecast production (Figure 3.5).

Figure 3.5. Biodiesel and HVO forecast overview



In the **United States**, biodiesel and HVO production rose 30% in 2018, reaching a record 7.8 billion L. Demand spurred by the RFS2 underpinned increased production, as biodiesel and HVO qualify for both the biomass-based diesel and advanced biofuel categories. Other factors supporting robust production were an abundant soybean crop and the imposition of anti-dumping duties on imports from Indonesia and Argentina that rendered them uneconomic.

Output is expected to increase strongly to 12.5 billion L by 2024 (Figure 3.5). Given stagnant diesel demand and stable exports, expanded production is based on gradually rising domestic demand to comply with the RFS2 and California's Low Carbon Fuel Standard (LCFS).

Biodiesel and HVO will be the main sources used to meet the higher renewable fuel demand from the RFS2 until 2022, given that corn ethanol has already reached the allowed limit and cellulosic ethanol production remains minimal. Significant investment in HVO capacity, referred to as renewable diesel in the United States, means it makes a larger contribution to forecast growth than biodiesel.

California accounted for 8% of US diesel demand in 2017, and tighter annual carbon intensity requirements of the state's LCFS will stimulate demand for low-carbon biodiesel and HVO from waste and residue feedstocks. Biodiesel and HVO already provided 30% (by volume) of the lower-carbon-intensity fuel consumed under the scheme in 2018.

In **Indonesia**, the biodiesel market is in transition from being export-driven to serving higher domestic consumption. Production was 4 billion L in 2018, and output is anticipated to expand 90% over the forecast period, to 7.5 billion L. Growth is delivered by new plants coming online and by underutilised capacity ramping up production.

This upward revision of the forecast reflects 2018 regulations that extended biodiesel consumption to new market segments not covered in the B20[14] mandate – rail, power generation and certain industrial sectors – thus ensuring higher domestic demand. Higher biodiesel consumption from the transport mandate is augmented by 10% diesel demand growth over 2019-24. Although an increase to B30 fuel in the transport mandate starting in 2020 is not considered within the main case forecast, it remains a possibility with vehicle testing under way.

Indonesia's oil import dependency is rising as demand increases and domestic production falls. Improving security of supply is therefore a key aim of measures that support domestically produced biodiesel consumption in transport.[15]

Higher domestic consumption, combined with trade barriers in key export markets, is likely to reduce the share of production exported over the forecast period. In addition to US anti-dumping duties, the requirement to scale down and ultimately phase out high indirect land use change (ILUC) biofuel consumption in the European Union may have an impact on some Indonesian palm oil biodiesel. Sustainability certification covered around 17% of Indonesian palm oil production in 2018, but biodiesel producers will have to compete with the cosmetics and food production industries to obtain certified-sustainable palm oil.

Brazil produced a record 5.2 billion L of biodiesel in 2018 – a 20% y-o-y increase – with soybean oil as the main feedstock, accounting for 70% of production. A good soybean harvest, combined with stronger demand resulting from the blending mandate being increased to 10% in 2018, spurred greater production.

Output growth of almost 30% is forecast to 2024, with production scaling up to around 6.5 billion L and consequently reducing current biodiesel plant overcapacity. The primary

[14] B20 indicates 20% biodiesel blending with fossil-based diesel, while B7 refers to a 7% blend, B10 equals 10% and B30 equals 30%.
[15] Further analysed in Chapter 5.

impetus for higher output is a staged mandate increase to 15% by 2023, starting with a rise to 11% in September 2019. Incremental increases will be dependent on automotive industry testing to assess the effects of using higher blend levels, so the possibility of increases not being implemented places downward pressure on the forecast. Diesel demand is also anticipated to increase 8% during 2019-24, and the introduction of the RenovaBio policy in 2020 may stimulate more output from lower-carbon waste oil and animal fat feedstocks.

Table 3.3. Annual production in other key biodiesel and HVO markets (billion L)

Country/ region	2018 output	2024 output	Forecast revision	Forecast overview
Argentina	2.7	2.3	▲	B10 mandate; 4% increase in diesel demand; 1.4 billion L/year tariff rate quota agreed for EU exports; exports to the United States remain closed.
Thailand	1.6	2.1	▼	Transition from B7 to B10 in 2020 is assumed; 10% increase in diesel demand; voluntary B20 for road freight and public transport began in 2018.
China	1.0	2.3	►	Stable diesel demand; limited policy support; most output from used cooking oil (UCO); higher imports from ASEAN; growth in line with 13th Five-Year Plan.
Malaysia	1.1	1.2	►	Transition from B7 to B10 mandate in 2019; 9% increase in diesel demand; current plant overcapacity; uncertainty over future EU exports.

Note: Up arrow indicates forecast revised upwards from last year, down arrow indicates forecast revised downwards, and right arrow indicates forecast has remained stable.

Conventional biofuels: Accelerated case forecast

With more favourable market conditions and enhanced policies, conventional biofuel production could expand a further 20%, to reach 225 billion L by 2024 and meet 6% of road transport fuel demand.

In the accelerated case (Table 3.4), annual ethanol production is 155 billion L by the end of the forecast period, or 25 billion L more than in the main case (19% higher).

Table 3.4. Annual ethanol production, accelerated case (billion L)

Country/ region	2024 output acc. case	% increase above main case	Market overview
China	20.5	85%	10% ethanol blending nationwide; significant additional investment in new production capacity; rollout of fuel supply infrastructure.
United States	67.0	8%	Expanded E15 supply and consumption, such that ethanol meets 12.5% of gasoline demand; access to new markets raises exports to 10 billion L.
European Union	7.7	48%	Faster scale-up of demand by 2020 and implementation of the 1% increase permitted under the RED;[16] expansion of E10 in more member states and E95[17] in road freight.
India	6.2	60%	Ethanol meets 13% of gasoline demand by 2024 to be on track for 20% by 2030; streamlined OMC procurement; interstate permitting and refinery storage barriers reduced.
Brazil	40.0	5%	RenovaBio facilitates new capacity deployment; low levels of lost capacity from sugar mills in debt; transition to new cane varieties; robust increase in corn ethanol production.
Other countries	10.2	58%	Argentina, Canada, Mexico, the Philippines and Thailand.

Note: OMC = oil marketing company.

In the accelerated case, biodiesel and HVO output climbs to 70 billion L by 2024 (Table 3.5), a 12.5-billion-L (22%) increase from the main case.

Table 3.5. Annual biodiesel and HVO production, accelerated case (billion L)

Country/region	2024 output acc. case	% increase on main case	Market overview
United States	16.0	85%	Ongoing support from RFS2 post-2022; LCFS frameworks in more states; long-term availability of tax credit; higher HVO output boosted by demand from road freight.
European Union	18.5	8%	Faster scale-up of demand by 2020 and implementation of the 1% increase permitted under the RED; higher HVO output boosted by demand from road freight.
Indonesia	9.0	48%	B30 in road transport; biodiesel introduced in industry sector; larger volumes of certified-sustainable supplies maintain and open up access to export markets.
India	1.6	six-fold increase	2% of diesel demand met by biodiesel by 2024 to be on track for 5% by 2030; supply chains for FOG feedstocks are mobilised; higher uptake in rail and captive fleets.
Brazil	8.0	20%	Higher blend shares approved by automotive industry; higher voluntary use in captive fleets; feedstock diversification (e.g. more tallow); HVO industry start-up.
Other countries	9.8	39%	Argentina, China, Malaysia, Singapore and Thailand.

[16] The updated RED permits member states to increase the contribution of conventional biofuels to renewable energy in transport by up to only 1 percentage point from the 2020 level.
[17] E10 is available in Belgium, Bulgaria, Finland, France, Germany and Luxembourg. The Netherlands is supposed to make E10 available in 2019. E95 is 95% ethanol, with lubricants and additives to improve ignition and protect against corrosion.

Whether the accelerated case can be achieved depends on several factors outside of government and biofuel industry control. First, the suitability of vehicle fleets will dictate the pace at which higher blends rates can be introduced. In several markets (e.g. India for ethanol and Indonesia for biodiesel), automotive industry testing is needed before blending mandates can be increased.

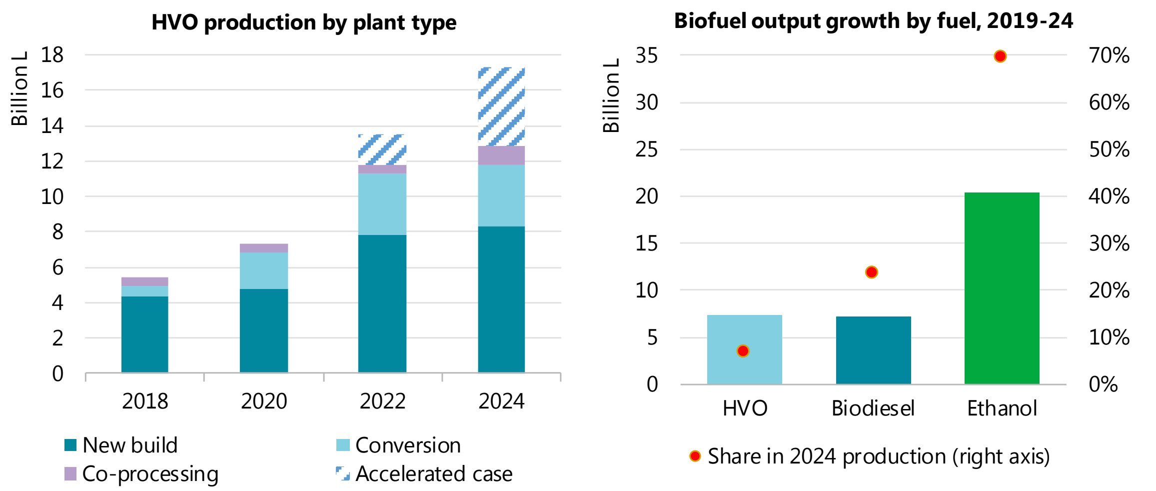
For crop-based feedstocks, weather conditions affect price and availability, and for ethanol markets the price of sugar determines the attractiveness of ethanol production. For instance, ethanol production in Brazil and India rose significantly in 2018 because international sugar prices were low. Crude oil prices also affect the competitiveness of transport biofuels with fossil fuels for consumers and determine how much subsidisation is required under policy frameworks (e.g. in Indonesia and Thailand).

Focus on HVO

HVO production is set to more than double in the main case during 2019-24, from around 5.5 billion L to almost 13 billion L (Figure 3.6), as policy frameworks in Europe and the United States spur significant investment in new capacity to meet higher demand. HVO makes up the largest share of advanced biofuel output growth over the forecast period. Most new plants intend to use waste and residue feedstocks for production, so mobilising supply chains for these feedstocks will be crucial to deliver forecast production growth.

HVO accounts for one-fifth of all forecast biofuel output expansion, a contribution similar to that of biodiesel, indicating its growing importance in global biofuel markets. Despite this strong increase, however, HVO still accounts for less than 10% of cumulative biofuel production in 2024 (Figure 3.6).

Figure 3.6. HVO production forecast and comparison with other biofuels



Output growth in the main case reflects USD 5 billion of investment in HVO plants, mostly for new refineries. The capacity of fossil fuel refineries converted to HVO production also increases because investment costs are lower and project delivery is quicker than for new-build plants. The co-processing of biomass feedstocks to produce HVO in fossil fuel refineries makes up a smaller portion of forecast growth.

Additional projects are included in the accelerated case, but they are at an early stage of development.[18] Their delivery would boost HVO production to around 17 billion L by 2024, with investments of USD 7.5 billion in new capacity.

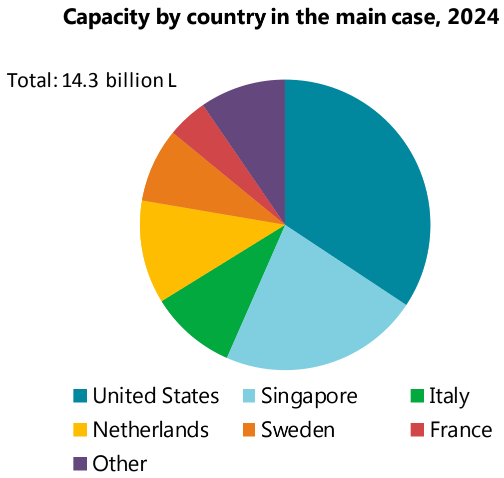
Because of its technical characteristics, HVO is less constrained by blend limits than biodiesel, offering higher flexibility for blenders. Technically a "drop-in" fuel, it can be used unblended (HVO100) in some diesel engines and without modifications to fuelling infrastructure. However, blends with fossil diesel (e.g. 30-50% by volume) are more common, with the blend rate determined by factors such as the cost of HVO relative to fossil diesel, and fuel supply logistics.

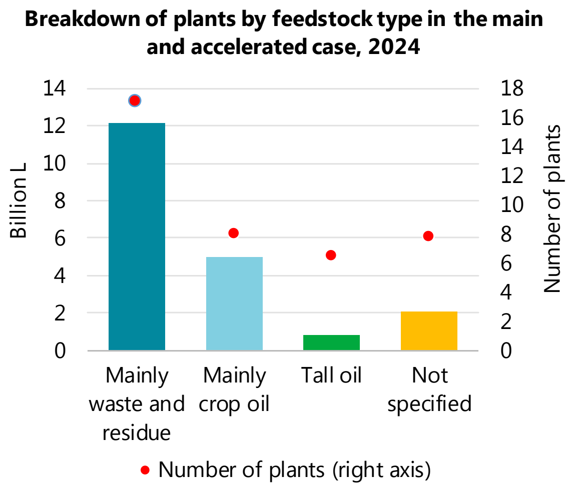
For fossil diesel that does not comply with fuel specifications, blending with HVO can improve its characteristics. HVO's high cetane number indicates it has good cold-start properties. In addition, its low aromatic content means it emits lower levels of air pollutants than fossil diesel when used in vehicles with older, less sophisticated engines and exhaust after treatment.

The higher value of co-products from HVO production, compared with those from biodiesel, also explains its growing market share. Glycerine, the primary co-product from biodiesel production, has food and cosmetics applications, but its value is lower than that of the propane, naphtha and chemicals that are part of an HVO plant's product slate. HVO refineries can also produce renewable aviation biofuel.

Europe and the United States currently dominate HVO production and, judging by upcoming projects, this will still be the case in 2024 (Figure 3.7).

Figure 3.7. HVO capacity in the main and acclerated cases, 2024





Note: Tall oil is a by-product of the pulp and paper industry.

[18] Financial close has not been reached and feedstock is unspecified.

In Europe, the updated RED policy framework for 2021-30 offers scope to increase waste- and residue-based HVO consumption. Fuels produced from UCO and animal fat feedstocks are permitted to make up 1.7% (before double-counting provisions are applied[19]) of the 14% renewable energy in transport targeted for 2030, equivalent to approximately 5.5 billion L of HVO. In addition, member states can request that the European Commission raise the cap, provided there is evidence of adequate feedstock availability. There is not a cap on production from other feedstocks (e.g. tall oil).

In the United States, the RFS2 and California's LCFS are driving HVO deployment: it accounted for 5% of fuels used in compliance with the RFS2 in 2018 and 20% under the LCFS. The RFS2 runs until 2022, with its continuation thereafter yet to be determined, whereas California's LCFS is in place until 2030. The state of Oregon and the Canadian province of British Columbia also have similar policies.

The carbon intensity reduction offered by a fuel relative to its cost determines the attractiveness of using that fuel to comply with LCFS policy frameworks. The HVO used to meet California's LCFS is produced primarily from low-carbon feedstocks such as tallow, technical corn oil[20] and UCO. Consequently, the average carbon intensity of the HVO used for compliance in 2018 was 65% lower than that of fossil diesel, yielding a value of USD 0.34/L based on average LCFS credit prices in 2018.

Requirements of the policies supporting HVO demand in Europe and the United States imply that most production in 2024 will be from waste and residue feedstocks (Figure 3.7, right), which offer the lowest lifecycle emissions. Of the plants already operational and in development, two-thirds plan to use mainly UCO, animal fat and other waste and residue feedstocks, and others intend to supplement the primary use of oil-crop feedstocks with a portion of wastes and residues.

Sourcing waste and residue feedstocks economically is therefore crucial to attain the main and accelerated case forecasts. The dispersal of UCO and animal fat resources over a wide area means that further mobilisation of supply chains will be required, so businesses that aggregate scattered feedstock supplies and the traders that form the links will play a key role in ensuring that biofuel producers do not need to expand their core business into low-volume supply procurement.

While UCO and animal fat feedstock supplies are ultimately finite, they are adequately available to allow for considerable scale-up of current HVO production. Nevertheless, attaining the main and accelerated case forecast volumes may require Europe and the United States to source supplies from a wider range of countries – especially Europe, where the collection market for UCO is approaching saturation (China already supplied 30% of Europe's demand in 2017 [Greenea, 2018]). Creating an alternative market for UCO also has the associated benefit of limiting excessive reuse of cooking oil unfit for human consumption, which is a prominent health issue in China, India and other countries.

[19] Under the RED, countries can enact provisions to double-count the energy content of biofuels made from UCO and animal fats towards the transport renewable energy target. This also applies to other biofuels classified as advanced within the RED.

[20] A non-edible residue from corn ethanol production.

Technological development of pre-treatment to expand the range of waste and residue feedstocks suitable for HVO production is anticipated in the forecast period. The leading global HVO producer has invested in pre-treatment research and development, and more than 80% of its feedstocks were from waste and residues in 2018 (Neste, 2019). Another means of producing low-carbon HVO is to electrolyse water with renewable electricity to generate the hydrogen needed for the production process. A project in Paraguay proposes to use this approach.

Although concrete project development in Indonesia is not yet evident, interest in HVO production has been expressed. Should projects materialise, it is likely that palm oil and palm oil mill effluent would be used as feedstocks.

Aviation biofuel forecast

Hydroprocessed esters and fatty acids synthetic paraffinic kerosene (HEFA-SPK) is currently the only aviation biofuel with notable commercial availability, and forecast HVO capacity growth strengthens prospects for higher HEFA-SPK production. The one refinery that currently offers continuous production has planned to expand its capacity significantly, and seven new HVO projects have indicated they will also produce the fuel. The delivery of these projects, along with two additional plants based on Fischer-Tropsch technology that are in development, could result in 1 billion L of aviation biofuel production by 2024 in the main case (Table 3.6).

Table 3.6. Aviation biofuel forecast overview (million L)

2018 production	2024 main case production	2024 accelerated case production	1% of aviation fuel demand (2024)
15	1 000	2 800	4 500

Under the accelerated case – which assumes that additional projects are deployed, new plants come into use more quickly, and HEFA-SPK makes up a larger portion of refinery products – aviation biofuel production reaches almost 3 billion L. However, even this level of output is equivalent to less than 1% of anticipated aviation fuel demand in 2024 (Table 3.6).

Enhanced policy support for aviation biofuels in the United States and several European countries should ensure higher demand, which would underpin production growth. Nevertheless, more widespread policy support and narrowing of the cost gap between HEFA-SPK and fossil jet kerosene will also be required for production to expand as forecast.

Approval of HEFA+ (a fuel with a similar quality specification to HVO's) for use in aviation in blends of up to 15% is currently under consideration. While not included in the accelerated case, the approval of HEFA+ could increase aviation biofuel output even further because it has a lower cost premium than HEFA-SPK compared with fossil jet kerosene and is easier to produce at existing HVO facilities.

Advanced biofuels markets

Advanced biofuels accounted for 9% of biofuel production in 2018, with 13.5 billion L made from non-crop-based waste and residue feedstocks (Table 3.7). Most of this production (an estimated 12 billion L[21]) was biodiesel and HVO made from FOG feedstock; novel advanced biofuels produced using less mature technologies from lower-cost, higher-availability feedstocks (e.g. agricultural residues and municipal solid waste [MSW]) made up only a small share of advanced biofuel production. Even by 2024, novel advanced biofuels account for only 1.5-2% of total biofuel production, as the high risk of investing in commercial-scale refineries using first-of-a-kind technologies, in addition to currently high production costs, hampers growth.

Table 3.7. IEA advanced biofuel definitions

Fuel	Definition	Technology example
Advanced biofuels	Sustainable fuels produced from non-food-crop feedstocks, capable of significantly reducing lifecycle GHG emissions compared with fossil fuel alternatives, and which do not directly compete with food and feed crops for agricultural land or adversely affect sustainability.	Biodiesel, HVO and biomethane, when waste/residue feedstocks are used.[22]
Novel advanced biofuels	Advanced biofuels made using technologies that are not yet fully commercialised.	Cellulosic ethanol and other biofuels made through thermochemical processes. HVO when 100% waste/residue feedstocks are used.

Note: These are the categories used for IEA forecasts and long-term modelling scenarios; they may differ from the definitions used under various policy support schemes.

Most of the biodiesel and HVO produced from FOG resources came from the European Union and the United States because they have policies that place a premium on feedstocks that deliver biofuels with very low lifecycle CO_2 emissions. Significant feedstock resources in Brazil (tallow) and China (UCO) also place these countries among the largest global producers.

Table 3.8. Biofuel production overview 2018 (billion L and %)

Conventional ethanol	Conventional biodiesel and HVO	Advanced biodiesel and HVO	Novel advanced biofuels
110 (71%)	31 (20%)	12 (8%)	1.4 (1%)

The production of biodiesel and HVO from FOG feedstocks is technically mature, and these fuels emit far less GHG emissions than fossil diesel, while also creating fewer land-use-change

[21] Output is estimated because exact data on the production of biodiesel and HVO from waste and residue feedstocks are unavailable.

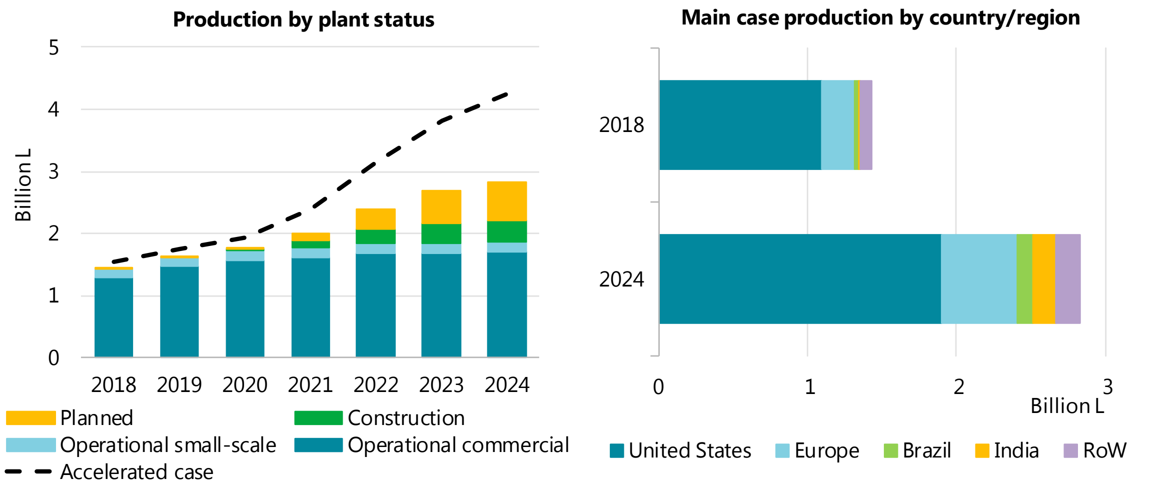
[22] Biodiesel and HVO plants that use oil crop feedstocks along with wastes and residues are included in the conventional biofuel forecast. Biomethane is not covered in the advanced biofuel forecast because data on production from waste and residue feedstocks subsequently used in transport are lacking.

concerns than conventional (crop-based) biofuels. Although there is potential to scale up production, feedstock availability is ultimately finite. For this reason, fuels made from these feedstocks constitute only part of the portfolio of low-carbon biofuels needed to decarbonise the transport sector in the long term.

In addition, even though they are less technically mature, there continues to be interest in other novel advanced biofuel technologies that utilise lower-cost, higher-availability feedstocks such as MSW and agricultural and forestry residues.

Renewables 2019's forecast for novel advanced biofuels details the status of technologies that require ongoing support to overcome financial, technical and market barriers (Figure 3.8). Novel advanced biofuel production doubles from 1.4 billion L in 2018 to 2.8 billion L in 2024 in the main case, an upward revision of last year's forecast to account for higher HVO production from plants exclusively using waste and residue feedstocks.

Figure 3.8. Novel advanced biofuel forecast overview



Despite ongoing development in the sector, most production at the end of the forecast period comes from plants that are currently operational.

The high investment risks associated with constructing commercial-scale refineries that use first-of-a-kind technologies impedes more significant production growth: at present only one-fifth of announced projects have secured the necessary construction financing. Furthermore, while the forecast identifies around 120 novel advanced biofuel projects, half of these are small-scale demonstration plants with low levels of production.

In the accelerated case, novel advanced biofuel output reaches 4.2 billion L by 2024, an almost threefold increase from 2018 production, which corresponds to just over 2% of total forecast biofuel production. The accelerated case assumes that 60% of announced projects get developed as a result of better investment conditions for advanced biofuel facilities.

Efficient and reliable performance of the first commercial plants is required to reduce investment risks for replication projects, and operational learning and improved pre-treatment processes are necessary to quickly scale up output to rated capacity.

As supportive policy frameworks are in place in the European Union, India and the United States, these countries account for most production in 2024 (Figure 3.8). However, quota policies guaranteeing fuel offtake in a greater number of countries (especially China and Brazil) would support not only accelerated case amounts, but even greater production.

Financial de-risking is also crucial to deliver higher advanced biofuel production, and policies designed for this purpose already encourage project development in countries at the forefront of this industry. In India, partial grant funding is available for up to 12 commercial-scale cellulosic ethanol plants developed under public-private partnerships, whereas loan guarantees support advanced biofuel projects in the United States and project co-funding is available in Canada.

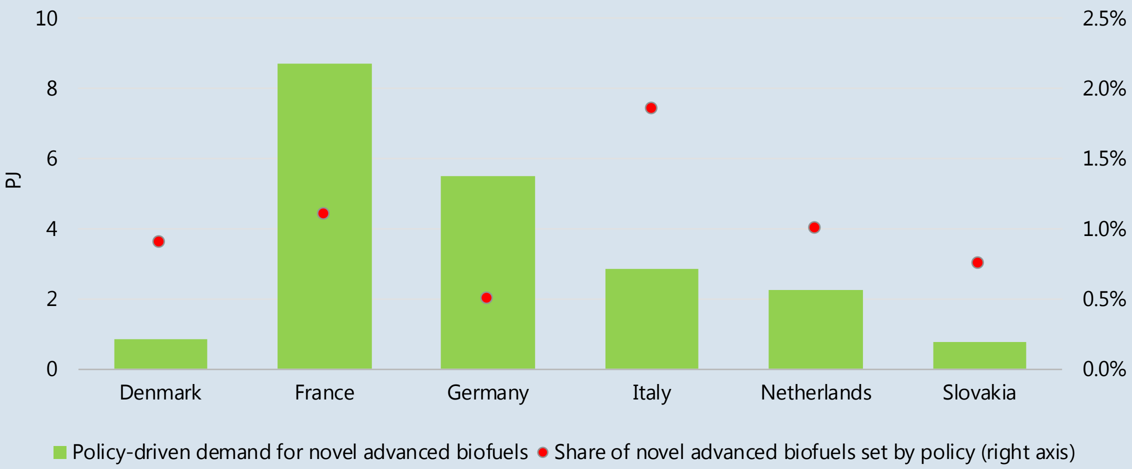
Box 3.2. How will EU targets affect novel advanced biofuel demand in 2025?

The RED policy framework ensures long-term EU demand for novel advanced biofuels, and if the targets included in policies already outlined by some member states to raise consumption are met, they will prompt investment in new technologies and encourage biofuel feedstock diversification – and take the European Union half way to its 2025 interim target. Nevertheless, realising the RED target for 2030 will require policy support in more member states, in addition to progress in the development of less mature technologies.

The updated RED for 2021-30 stipulates that 1.75% of transport fuel demand in 2030 (before double-counting provisions are applied) should be met by fuels categorised by the IEA as novel advanced biofuels. Thirteen member states explained how they intend to fulfil this requirement in their draft National Energy and Climate Plans (NECPs) submitted to the European Commission: ten have already defined quota policies that will raise demand for novel advanced biofuels beyond 2020, and three have established a target for 2020.

The fulfilment of current policies in these 13 member states will result in 32 petajoules (PJ) of novel advanced biofuel demand in 2025, which is significant considering that global production of novel advanced biofuel was around only 44 PJ in 2018.

Novel advanced biofuel demand from quota policies in 2025, in energy terms



Notes: France's policy requires 1.8% of gasoline and 0.85% of diesel demand (by energy) to be met by advanced biofuels. Transport energy demand in 2025 is based on IEA analysis. Double-counting provisions are assumed for all countries, although double-counting status for Germany and Slovakia in 2025 had not been defined at the time of writing.

Furthermore, the majority of novel advanced biofuel production in 2018 came from plants that used only UCO and animal fat feedstocks, which do not count towards the 1.75% RED target. Fuels from these feedstocks fall under a separate quota of 1.7% of EU transport energy demand in 2030 (before double-counting).

As novel advanced biofuel output from other feedstocks amounts to less than 10 PJ, meeting these mandates will require a rapid scale-up in the production of cellulosic ethanol, biomethane and biofuels from thermochemical processes that use different feedstocks. The NECPs of the Czech Republic, Estonia and Italy indicate that biomethane will be the main fuel used to meet their advanced biofuel policy goals.

If all currently defined EU member state quotas are met, novel advanced biofuels will supply 0.5% of EU transport energy consumed in 2025 – half of the 1% interim target for the European Union as a whole. This takes into account the RED provision that permits member states to count the energy content of advanced biofuels twice; without double-counting, the amount of anticipated EU transport demand covered by novel advanced biofuels in 2025 falls to 0.25% (in energy terms).

Nordic countries are at the forefront of advanced biofuel project development. Aside from Denmark (0), Finland has established a 30% target for biofuels in road transport by 2030, without double-counting. Sweden, which already has the highest share of renewable energy in transport in the European Union, has committed to reduce domestic transport GHG emissions 70% by 2030 (from the 2010 level, excluding aviation). A CO_2 emissions reduction obligation for fossil fuel suppliers and large consumers is in place to support this target, as are energy and carbon taxation, demonstrating that quota polices are not the only policy tool to encourage biofuel deployment.

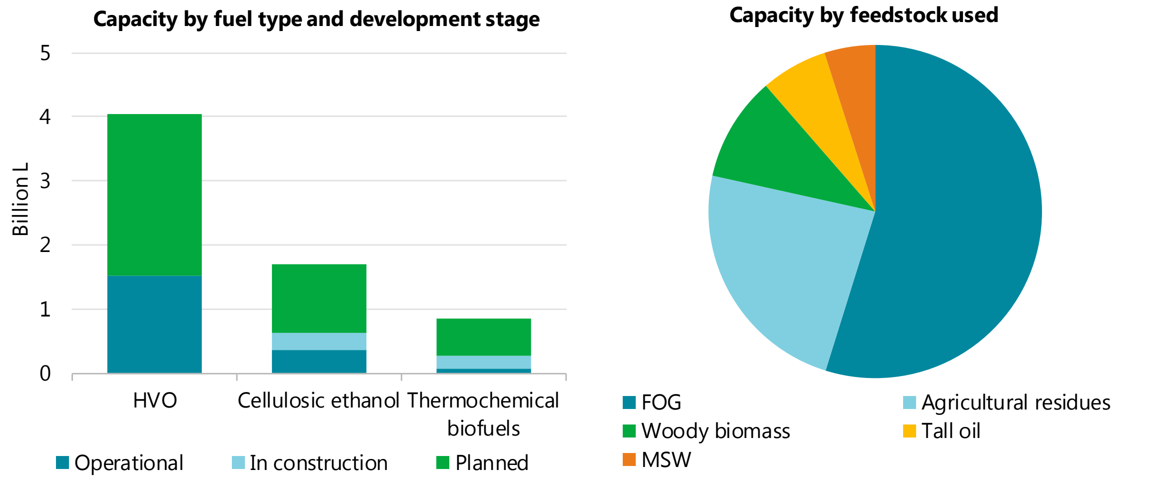
Although a range of novel advanced biofuels can be used to meet the EU target, to give an indication of the level of investment needed, if cellulosic ethanol were used exclusively to meet announced quotas, consumption of 1.3 billion L would be required in 2025.

This amount – far higher than current global production – equates to the output of roughly 30 commercial-scale refineries, compared with the four currently operational, and approximately USD 3.5 billion of investment by 2025. Nevertheless, this is significantly less than global investments in biofuel production in 2018 of around USD 6 billion (equal to 1% of total fuel supply investments) and is far below oil refinery investments of USD 24 billion last year.

Although the emergence of policies under the RED framework guaranteeing that novel advanced biofuel offtake will stimulate the advanced biofuel industry, over half of EU member states have yet to present advanced biofuel policies to reach the 2030 target. Therefore, scaling consumption up further will require stronger policy ambition from not only more EU member states but other countries, since imported novel advanced biofuels can also be used to achieve the goal.

The largest operational capacity of all novel advanced biofuel technologies is currently for the production of HVO exclusively from FOG and tall oil feedstocks, and numerous additional projects are in development (Figure 3.9).

Figure 3.9. Advanced biofuel technology and feedstock overview



Note: Graphs refer to plants currently operational or in development as of June 2019. Only HVO plants that use 100% waste and residue feedstocks are included in the novel advanced biofuel forecast.

Even though most new capacity in construction is dedicated to cellulosic ethanol, production from commercial-scale facilities remained below rated capacity in 2018 despite some progress in scaling up output. Several of these plants are in an extended commissioning phase because of the intense learning curve required to raise yields and utilisation rates through core-process optimisation, design improvements and modifications to improve reliability. The principal feedstocks for cellulosic ethanol are agricultural residues such as bagasse and corn stover.[23]

Several conventional corn ethanol plants in the United States have installed technology to produce cellulosic ethanol from corn fibre residues, resulting in 2-4% of production coming from cellulosic feedstocks. Replication across the approximately 200 US corn ethanol plants could increase cellulosic ethanol production to 1-2 billion L.

The accelerated case assumes that ten plants install such technology each year. Furthermore, with corn ethanol production in China, Argentina and Brazil (in addition to other countries), there is potential for a more widespread rollout should policies such as certificate schemes and low-carbon fuels standards and mandates be established to ensure a premium price and/or captive demand for cellulosic ethanol.

Advanced biofuel production from thermochemical processes is currently minimal, with most facilities still at demonstration scale. Interest in these technologies persists, however, owing to their potential to make use of solid biomass and MSW feedstocks (Figure 3.9). Consequently, 200 million L of capacity is in construction and there are 600 million L worth of planned projects.

[23] *Bagasse* is the residue left after the juice has been extracted from sugar cane. *Corn stover* refers to the leaves, stalks and cobs left after corn (maize) has been harvested.

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4. Renewable heat

Highlights

- Accounting for 50% of global final energy consumption in 2018, heat is the largest energy end-use and contributes 40% of global carbon dioxide (CO_2) emissions. Industrial processes account for half of global heat consumption while the other half is used mostly in buildings for space and water heating as well as cooking, and for agriculture. Fossil fuels continue to dominate heat supplies, while modern renewables (i.e. excluding the traditional use of biomass) met only 10% of global heat demand in 2018. Renewable heat consumption expands 22% during the outlook period (2019-24), with its share reaching 12% by 2024. Overall, this projected deployment is not in line with global climate change targets. Greater ambition and stronger policy support are needed to ramp up the use of renewables for heat and to improve energy efficiency in both buildings and industry.

- **Modern bioenergy accounted for more than two-thirds of global renewable heat consumption in 2018**, with a higher penetration in industry than in buildings. Bioenergy is expected to lead renewable heat expansion, its use rising 12% during 2019-24, with almost two-thirds of this increase in industry. India is anticipated to nearly catch up with Brazil as the largest industrial bioenergy consumer thanks to extensive bagasse use in its sugar and ethanol industry. In buildings, direct and indirect uses of bioenergy together make up roughly half of renewable heat consumption globally. The European Union is expected to be responsible for more than half of the increase in bioenergy consumption in buildings, owing to the deployment of woodchip and pellet stoves as well as bioenergy consumption for district heating.

- **The amount of renewable electricity used for heat is projected to increase 41% over the projection period**, accounting for one-fifth of global renewable heat consumption by 2024 as the share of renewables in electricity generation rises and more electricity is used for heat generation. In absolute terms, this increase (two-thirds of which is in buildings) is almost equivalent to bioenergy expansion. The People's Republic of China ("China"), the European Union and the United states together are responsible for almost two-thirds of this growth. In China, renewable electricity consumption for heat increases as heat production is electrified and heat pumps become more widespread. In the European Union and the United States, rapid expansion in the share of renewables is the key reason for higher renewable electricity consumption for heat.

- **Having expanded 82% since 2013, solar thermal energy accounted for around 7% of global renewable heat consumption in 2018**. Despite a continuous decline in capacity additions in the last five years, solar thermal consumption is expected to increase almost 50% over the outlook period, mostly in buildings, with China still responsible for more than 40% of this growth, followed by the United States and the European Union.

- Policy attention and support for the uptake of renewables in the heating and cooling sector remains limited despite its large share in final energy consumption. Very few national heat policies were implemented, revised or extended in 2018, and new policy developments for renewable heat in industry were scarce. However, at the subnational level an increasing number of cities and local governments are using their regulatory and purchasing authority to encourage the use of renewables through municipal mandates and policies for buildings, and through their management of urban district networks. Given the local nature of the heat sector, subnational governments have a key role in scaling up renewables use.

Global overview and outlook

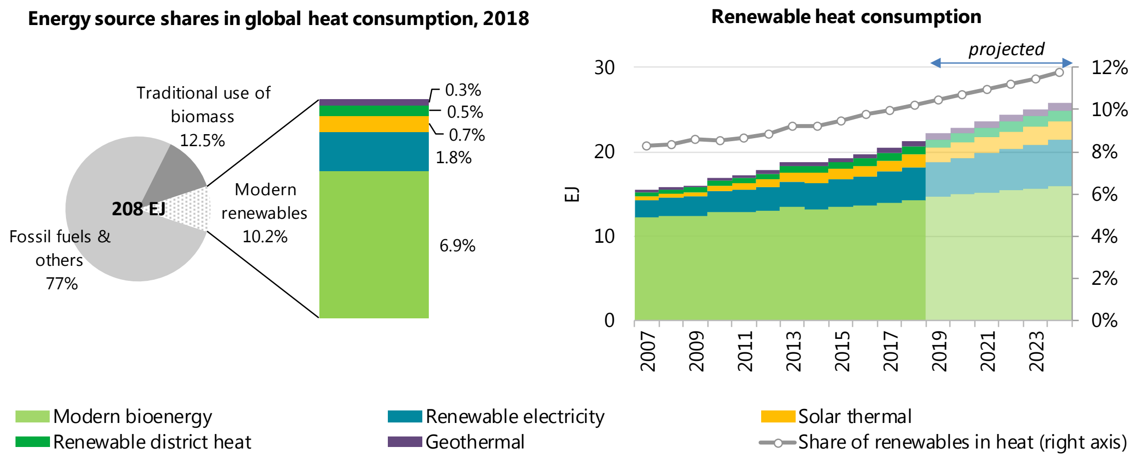
Heat accounted for half of global final energy consumption in 2018, remaining the largest energy end-use before transport (29%) and electricity (21%). About 50% of total heat produced was used for industrial processes, another 46% was consumed in buildings for space and water heating and, to a lesser extent, for cooking, while the remainder was used in agriculture, essentially for greenhouse heating.

With coal, natural gas and oil meeting more than three-quarters of global heat demand, the sector remains heavily fossil-fuel dependent (Figure 4.1). As a result, heat-related CO_2 emissions increased 9% during 2009-18. The sector contributed 40% (13.2 gigatonnes of carbon dioxide [$GtCO_2$]) of global energy-related CO_2 emissions in 2018, a share that has remained almost unchanged for the past decade.

The traditional uses of biomass, which generally induce negative human health, socioeconomic and environmental impacts, still account for more than 12% of global heat demand. Reducing such inefficient uses significantly will be required to advance towards the United Nations' 7th Sustainable Development Goal (SDG) of ensuring affordable, reliable, sustainable and modern energy access for all.

Along with energy efficiency improvements, direct and indirect uses of modern renewables[24] can help decarbonise the end-use sector and provide a cleaner and more sustainable heat supply.

Figure 4.1. Heat consumption by source, and renewable heat consumption outlook



Note: EJ = exajoules.

Sources: IEA (2019a), *World Energy Statistics and Balances 2019* (database), www.iea.org/statistics/; IEA (forthcoming), *World Energy Outlook 2019*.

[24] In this report, "modern renewable heat" excludes the traditional use of biomass. It covers direct and indirect (i.e. through district heating) final consumption of bioenergy, solar thermal and geothermal energy, as well as renewable electricity for heat, based on an estimate of the amount of electricity used for heat production and on the share of renewables in electricity generation. The term "modern bioenergy" also excludes the traditional use of biomass. For the sake of simplicity, "modern renewables" is referred to as "renewables" in the remainder of this report.

Although renewable heat consumption increased 19% over 2013-18, its share in overall heat demand amounted to around only 10% in 2018, much lower than that of renewables in electricity generation (25%). As renewable heat consumption is expected to continue expanding at the same pace, its share reaches only 12% by 2024 (Figure 4.1).

Bioenergy remains by far the largest renewable heat source and is expected to lead growth with a 12% (1.7 EJ) increase during 2019-24. The industry sector consumes two-thirds of total modern bioenergy, mainly for industrial processes.

Owing to the combination of heat electrification and the increasing penetration of renewables in the power sector, renewable electricity use for heat[25] increases 41% (1.6 EJ) globally over the period, showing similar absolute growth to bioenergy, with buildings accounting for more than two-thirds of it.

Table 4.1. Global trends and outlook for renewable heat, 2012-24

		2012 (EJ)	2018 (EJ)	2024 (EJ)	Total share of modern renewables in 2018	Historical growth 2013-18	Projected growth 2019-24	CAAGR 2013-18	CAAGR 2019-24	Change in CAAGR
Total energy consumption for heat		**201**	**208**	**219**	**9.8%**	**3%**	**6%**	**0.6%**	**0.9%**	▲
Total modern renewables for heat	**Total renewables**	**17.7**	**21.2**	**25.8**	**100%**	**19%**	**22%**	**3.0%**	**3.3%**	▲
	Modern bioenergy	13.1	14.3	16.0	67%	10%	11%	1.6%	1.8%	▲
	Solar thermal	0.84	1.53	2.24	7.2%	82%	47%	10.5%	6.5%	▼
	Geothermal	0.34	0.62	0.89	2.9%	83%	42%	10.6%	6.0%	▼
	Renewable electricity	2.81	3.81	5.39	18%	36%	36%	5.2%	5.9%	▲
	Renewable district heat	0.74	0.94	1.33	4.4%	26%	10%	4.0%	5.9%	▲
Industry and Agriculture	**Total renewables**	**9.3**	**10.9**	**12.9**	**100%**	**17%**	**18%**	**2.7%**	**2.8%**	▲
	Modern bioenergy	8.18	9.41	10.6	86%	15%	13%	2.4%	2.0%	▼
	Solar thermal	0.01	0.02	0.09	0.2%	34%	393%	5.0%	30%	▲
	Geothermal	0.07	0.13	0.15	1.2%	87%	16%	11%	2.6%	▼
	Renewable electricity	0.75	1.00	1.49	9.2%	34%	49%	5.0%	6.8%	▲
	Renewable district heat	0.30	0.36	0.60	3.3%	21%	65%	3.2%	8.7%	▲
Buildings	**Total renewables**	**8.4**	**10.3**	**12.9**	**100%**	**22%**	**25%**	**3.3%**	**3.8%**	▲
	Modern bioenergy	4.84	4.89	5.35	48%	1%	9%	0.2%	1.5%	▲
	Solar thermal	0.83	1.51	2.15	14%	83%	42%	10.6%	6.0%	▼
	Geothermal	0.27	0.49	0.74	4.8%	82%	49%	10.5%	6.9%	▼
	Renewable electricity	2.06	2.81	3.90	27%	36%	39%	5.3%	5.6%	▲
	Renewable district heat	0.44	0.58	0.73	5.6%	30%	27%	4.4%	4.0%	▼

Note: CAAGR= compound average annual growth rate.

Sources: IEA (2019a), *World Energy Statistics and Balances 2019* (database), www.iea.org/statistics/; IEA (forthcoming), *World Energy Outlook 2019*.

Following rapid deployment during 2005-13, **solar thermal** market growth has since slowed, with a decline in new capacity additions for the fifth year in a row last year due to shifting market dynamics in China. Despite this slowdown, solar thermal heat consumption is expected to remain

[25] The fraction of electricity used for heat that can be attributed to renewable sources, calculated based on national shares of renewable sources in electricity generation.

strong at an increase of almost 50% (+0.7 EJ) over 2019-24, of which 90% will be in buildings owing to its relatively low cost.

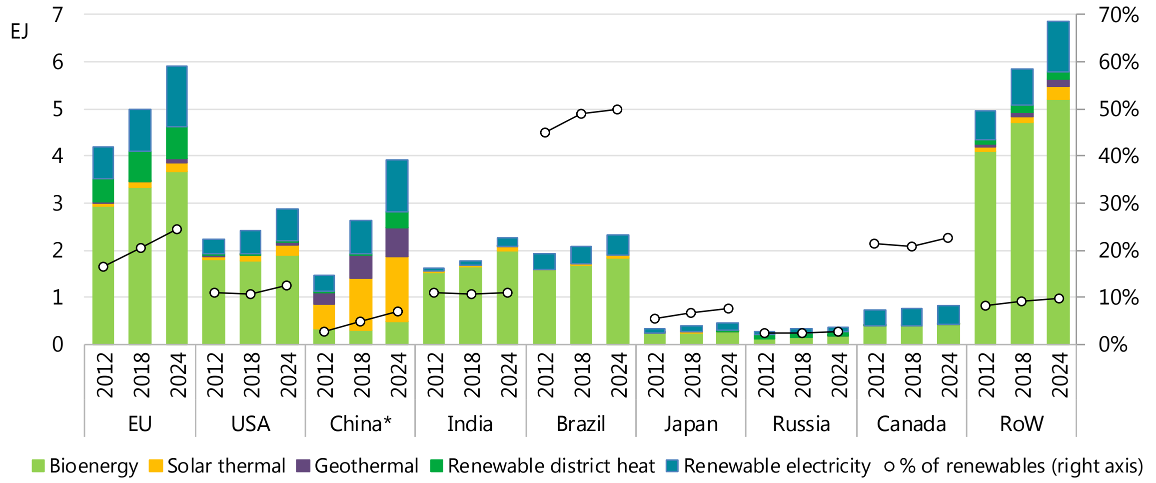
Although the **direct geothermal** share in global renewable heat consumption remains limited, it is projected to increase more than 40% (+0.3 EJ) over the outlook period, with almost two-thirds of this growth in China and the United States.

Regional trends and recent policy developments

China, the European Union, India and the United States together account for more than two-thirds of the increase in global renewable heat consumption during 2019-24 (Figure 4.2).

In **China**, overall heat demand is expected to level off, owing partly to greater energy efficiency and to a structural shift towards less energy-intensive economic activities. Renewable heat consumption expands 50% between 2018 and 2024, displacing another 1.3 EJ of fossil-based energy consumption annually by 2024. Solar thermal energy in buildings and renewable electricity lead this transition, motivated by air pollution concerns in cities and supported by policies such as the Clean Winter Heating Plan for Northern China introduced under the 13th Five-Year Plan (FYP), which set various renewables targets for 2021.

Figure 4.2. Renewable heat consumption for selected countries



*Although China does not currently report any renewable heat use in industry in its statistics, some bioenergy is consumed.
Note: RoW = rest of world.
Sources: IEA (2019a), *World Energy Statistics and Balances 2019* (database), www.iea.org/statistics/; IEA (forthcoming), *World Energy Outlook 2019*.

In the **European Union**, renewable heat consumption increases 19% in the next six years, meeting almost one-quarter of slightly declining (-1%) heat demand by 2024 (the slight decline is thanks to energy efficiency improvements). The 2018 revision of the Renewable Energy Directive (RED) should stimulate this expansion with its updated target of at least 32% renewables in final energy consumption (up from 27%) as well as a new indicative target to raise the share of renewables in heating and cooling by 1.3 percentage points annually. Final National Energy and Climate Plans (NECPs) are to be released by the end of 2019, outlining individual member country commitments towards the collective EU goals for 2021-30.

The **United States** displays a similar pattern, with heat demand growth decelerating and renewable heat consumption increasing 19% in 2019-24. More than three-quarters of the increase in renewable heat use is in buildings, of which renewable electricity for heat is anticipated to make the largest contribution, followed by solar thermal. This trend results mainly from an increasing penetration of renewables in the US electricity generation portfolio, which accounts for nearly 40% of the country's growth in renewable heat consumption over the outlook period, while the electrification of heat uses plays only a minor role.

In **India**, the share of renewables in heat remains flat at around 11% despite projected 26% growth in renewable heat consumption over 2019-24, due to a continually expanding share of fossil fuels being used to meet growing heat demand. Renewable heat uptake in India results mostly from increased bagasse use in the sugar industry, making it the largest single consumer of biomass for heat in 2024. Support schemes are currently in place for biomass co-generation,[26] biogas plants and solar thermal projects.

Thanks to the extensive use of biomass in the form of bagasse residues for co-generation in the sugar and ethanol industry, renewables account for almost half of **Brazil**'s heat consumption. However, the share of renewables is anticipated to remain almost unchanged from 2018 to 2024 despite a 12% increase in renewable heat consumption, as industrial heat demand growth accelerates as a result of economic recovery.

In **most other emerging and developing economies**, heat demand continues to rise, driven by economic and population growth. However, renewable heat consumption does not expand quickly enough to keep pace with demand, preventing an increase in the share of renewables.

Policy attention and support for the uptake of renewables in the heating and cooling sector remains limited despite its importance in final energy consumption. For instance, only 47 countries – mostly from the European Union – had national targets for renewable heat in 2018 (compared with 162 countries with targets for renewables in the power sector), and only 20 countries had nationwide regulatory heat policies in force (REN21, 2019a). These numbers have remained relatively flat in recent years, with very few national heat policies introduced or revised in 2018 and very limited new policy developments for renewable heat in industry.

At the subnational level, however, cities and local governments have shown more dynamism. An increasing number of cities are using their regulatory and purchasing authority to support the use of renewables through municipal mandates and policies for buildings, and through their management of urban district networks (REN21, 2019b). In 2018, for instance, Copenhagen set a target for its co-generation plants to be 100% biomass-fuelled by 2025, while many of the world's largest municipalities, including London, New York and Tokyo, have committed to achieve net-zero-carbon operating emissions in buildings (i.e. excluding construction and end-of-life emissions) by 2050. Given the local nature of the heat sector, subnational governments have a key role in scaling up renewables use.

Renewable heat policies are often implemented alongside energy efficiency measures. Building energy codes for new buildings and retrofits are currently one of the key regulatory instruments used to deploy renewable heating and cooling, while financial incentives consist mostly of loans, grants and investment subsidies. The EU energy label, which promotes energy-efficient heaters and places renewables-based heaters in the top categories, is another example of how energy efficiency policies can promote renewable heating. As an effective means to limit CO_2 emissions, renewables for heat also receive support under climate change strategies – either directly through specific targets for renewable energy, or indirectly through carbon emission targets and economic instruments such as carbon taxation (e.g. as in Sweden) or cap-and-trade systems (e.g. under the EU Emissions Trading Scheme).

[26] *Co-generation* refers to the combined production of heat and power.

The projected deployment of renewables in the heat sector during 2019-24 is significantly below the levels modelled in the International Energy Agency (IEA) Sustainable Development Scenario (SDS). According to the SDS, renewable heat use needs to expand 37% more quickly over the outlook period than what is forecast – with stronger increases in renewable electricity for heat and solar thermal for buildings especially – to meet long-term climate, clean-air and energy access goals (IEA, 2018a). Greater ambition and stronger policy support are therefore needed to ramp up renewables use for heat in both buildings and industry.

Table 4.2. Recent policy developments

Geography	Recent heat-related targets and policy developments
China	"100 Cities and Towns" plan; 136 biomass and waste co-generation demonstration projects.
European Union	Target of 32% of renewables in final consumption by 2030. Indicative target of 1.3% annual increase in renewable heating and cooling share over 2020-2030. Final NECPs to be released by the end of 2019 by each member country.
Denmark	Target (not legally binding) of 100% independent from fossil-fuels and net-zero emissions by 2050.
France	Heat fund budget increased by 14% to EUR 245 million.
Germany	Biomass and deep geothermal installations eligible for funding under the Market Incentive Programme (MAP).
United Kingdom	Heat Networks Investment Project (HNIP) offers grants and loans to public and private sectors. Changes in the domestic Renewable Heat Incentive (RHI) scheme (including revision of tariffs and the option for households to assign their RHI payment rights to investors).
Ireland	Installation grant for heat pumps and operational support for biomass and anaerobic digestion heating systems under the Support Scheme for Renewable Heat (SSRH), open to commercial, industrial, agricultural, district heating, public sector and other non-domestic heat users.
Croatia	Environmental Protection and Energy Efficiency Fund (FZOEU) offers EUR 1.5 million in grants for renewables in the residential sector, including for solar hot water.
Lithuania	Target of 90% renewables in heating and cooling by 2030.
India	Continuation of a capital subsidy scheme for installation of solar thermal systems. Fiscal support for investment in new bagasse co-generation systems.
Kenya	Solar water heater regulation suspended in August 2018.[27]
California (USA)	Revised energy standards for buildings with requirements for renewable energy use, including for heat pumps.
British Columbia (Canada)	The CleanBC plan, introduced in December 2018, offers rebates for heat pumps and support for renewable energy use in public infrastructure through the CleanBC Communities Fund; it targets 15% gas consumption from renewable sources.

[27] This regulation, introduced in 2012, made it mandatory for all premises with hot water requirements exceeding 100 litres per day to install and use solar water heating systems. Solar water heater uptake has remained low, however, due mainly to high upfront costs and a lack of confidence and awareness (EED Advisory, 2017). In 2018, the regulation was legally challenged based on property owners' rights.

Buildings

Global heat demand for buildings rises just 2.3% over the outlook period, driven mainly by population and building floor area expansion. However, regional trends vary depending on energy efficiency policies and their implementation. In the European Union and Japan, for instance, buildings sector heat demand has levelled off or even decreased slightly in the past decade, thanks to energy efficiency measures. Over 2019-24, modern renewables use is expected to increase 25% while the use of non-renewables in buildings begins to decline in absolute terms. The share of renewables in buildings is therefore estimated to increase from 11% in 2018 to 13% in 2024. China and the European Union together currently account for over half of renewable energy consumption in buildings and they are expected to lead growth over the period, followed by the United States and India (Figure 4.3).

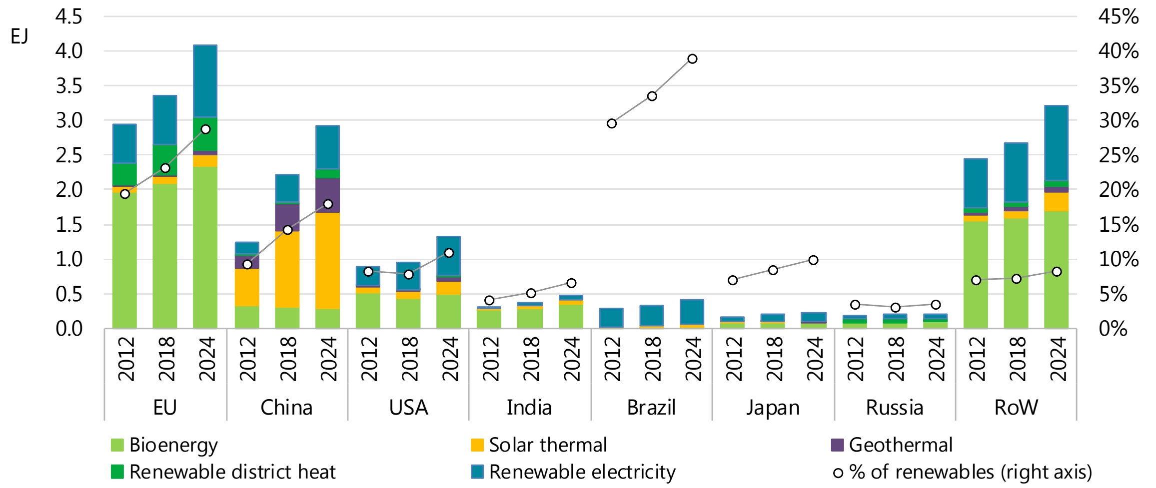
Despite demonstrating a relatively low CAAGR (1.5%), modern **bioenergy** remains the largest renewable heat source for buildings during the outlook period. Direct and indirect uses of bioenergy together account for roughly half of total renewable heat consumption in buildings globally, with the European Union responsible for 47% owing to the deployment of woodchip and pellet stoves and boilers, as well as the use of bioenergy in district heating networks.

Renewable electricity, which is currently the second-largest renewable heat source in buildings, is expected to contribute the greatest absolute growth (+1.1 EJ), led by the European Union (+0.33 EJ), China (+0.22 EJ) and the United States (+0.16 EJ). While the electrification of heat and the diffusion of heat pumps are important factors for greater renewable electricity use in China, greater penetration of renewables in the national electricity generation portfolios is the key factor in the European Union and in the United States.

Global **solar thermal** use for buildings is anticipated to expand 42% during 2019-24, with 44% of this increase in China despite a slowing market, and another quarter from the United States and the European Union together, where solar thermal growth is projected to accelerate.

A strong increase in direct **geothermal** use is also expected (+49%), albeit from a small base, again with China, the United States and the European Union together responsible for more than 80% of additional consumption.

Figure 4.3. Renewable heat consumption in buildings for selected countries

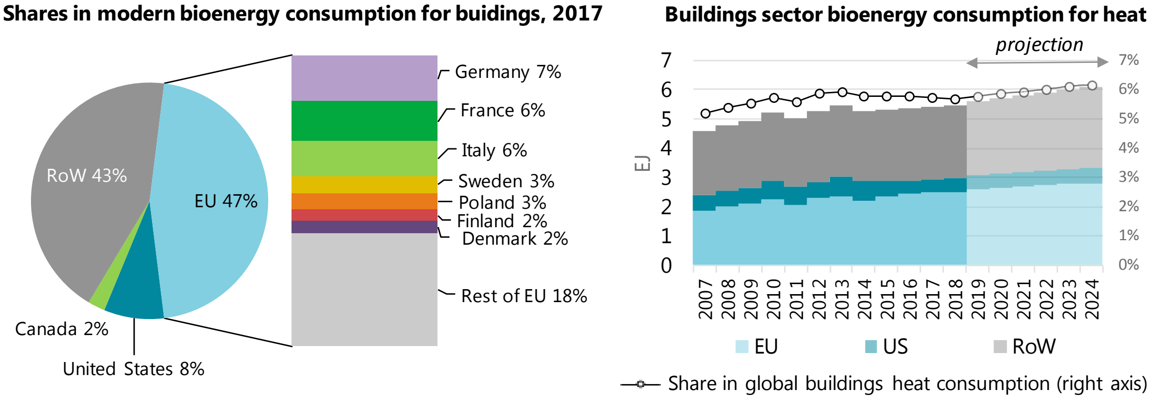


Sources: IEA (2019a), *World Energy Statistics and Balances 2019* (database), www.iea.org/statistics/; IEA (forthcoming), *World Energy Outlook 2019*.

Bioenergy

In 2018, modern bioenergy met around only 6% of total buildings sector heat demand worldwide. It accounted for 53% of all modern renewable heat consumption in the buildings sector globally, providing space and water heating through a range of technologies (e.g. solid biomass stoves, boilers and district heating networks). Residential buildings account for the majority of demand, while biomass heating consumption in commercial and public buildings is lower and results mostly from indirect use through district heating networks. Significant annual fluctuations in biomass consumption for buildings can occur as a result of prevailing weather conditions and fuel costs (i.e. compared with fossil fuels).

Figure 4.4. Modern bioenergy consumption in buildings



Sources: IEA (2019a), *World Energy Statistics and Balances 2019* (database), www.iea.org/statistics/; IEA (forthcoming), *World Energy Outlook 2019*.

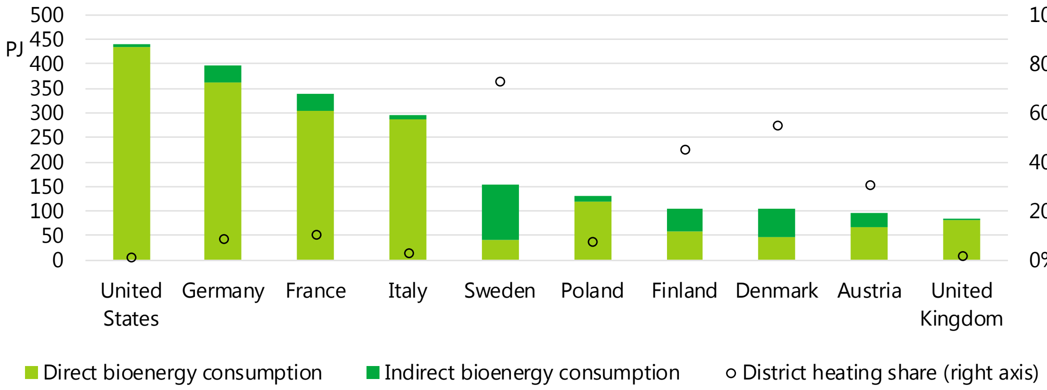
Modern bioenergy use in buildings has increased only 10% globally in the past decade, due partly to a lack of policy support. With 9% growth expected during 2019-24, modern bioenergy contributes less than one-fifth of the 2.6 EJ growth in buildings sector renewable heat consumption. Nonetheless, it remains the main renewable heat source over the next six years.

With the RED promoting renewable heat use, the **European Union** is the largest consumer of modern bioenergy for buildings at 47% (2.5 EJ) of global demand in 2018, half of which was in France, Italy, Germany and Sweden (Figure 4.4). These four countries – Italy first – lead Europe's steadily growing pellet consumption for heating, which reached 15 million tonnes (Mt) in 2017, up 12% from the previous year (Bioenergy Europe, 2018). Pellet stove installations in Europe have expanded more than fourfold in the last ten years. Italy leads deployment, with a cumulative 2.6 million systems in 2017 owing to a ten-fold increase in the last decade under the support of the *conto termico* scheme. In France, pellet stove installations have been expanding robustly since 2012 and further growth is anticipated as a result of carbon tax hikes and because the government has extended the tax credit scheme as well as introduced a premium for replacing low-efficiency fossil fuel appliances. Residential pellet boiler stocks are also expanding, although these appliances remain less common. District heating networks are another important application in the European Union, representing 17% of bioenergy consumed for heat in buildings in 2018, with Sweden, Denmark and Finland in the lead (Figure 4.5).

EU bioenergy use in buildings rises 0.28 EJ over the outlook period, to meet 20% of overall building heat demand, stimulated by the updated RED's indicative target for member states to increase the share of renewable energy in heating and cooling by 1.3 percentage points per year.

Following the European Union, the **United States** has the largest single-country consumption of bioenergy in the buildings sector. In 2017, about 2% of households (2.1 million) used wood as their primary heating fuel, with higher shares in the north-eastern and north-western states that have less well-developed natural gas network infrastructure. In these areas, the economic case for using biomass for heating is stronger because it is competing with heating oil, which is more expensive than natural gas. Another 8% of households used solid biomass as a secondary heat source (US EIA, 2018), which makes bioenergy consumption particularly sensitive to weather and fuel price fluctuations in the country. Overall consumption of bioenergy in buildings is expected to increase 14% (+60 petajoules) during 2019-24 owing to various state-level incentives.

Figure 4.5. Direct and indirect bioenergy consumption in buildings, selected countries, 2017



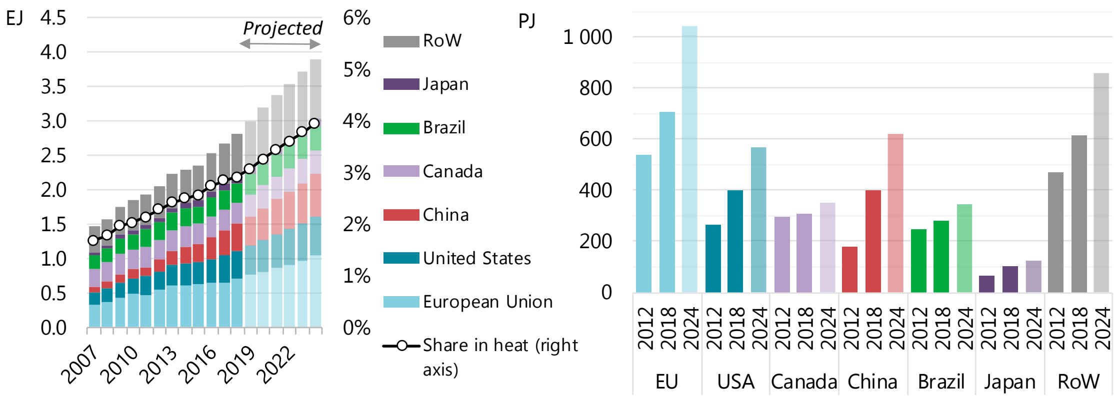
Note: Indirect bioenergy consumption refers to bioenergy consumed for district heating, while direct bioenergy consumption includes wood, woodchip and pellet stoves and boilers.

Source: IEA (2019a), *World Energy Statistics and Balances 2019* (database), www.iea.org/statistics/.

Renewable electricity for heat in buildings

Following bioenergy, renewable electricity is the second-largest renewable heat source in buildings, supplying 3% of total heat demand in 2018. The **European Union** was responsible for 25% of this consumption, with the **United States** and **China** together accounting for another 28%, followed by Canada and Brazil (Figure 4.6).

Figure 4.6. Historical and projected renewable electricity consumption in buildings

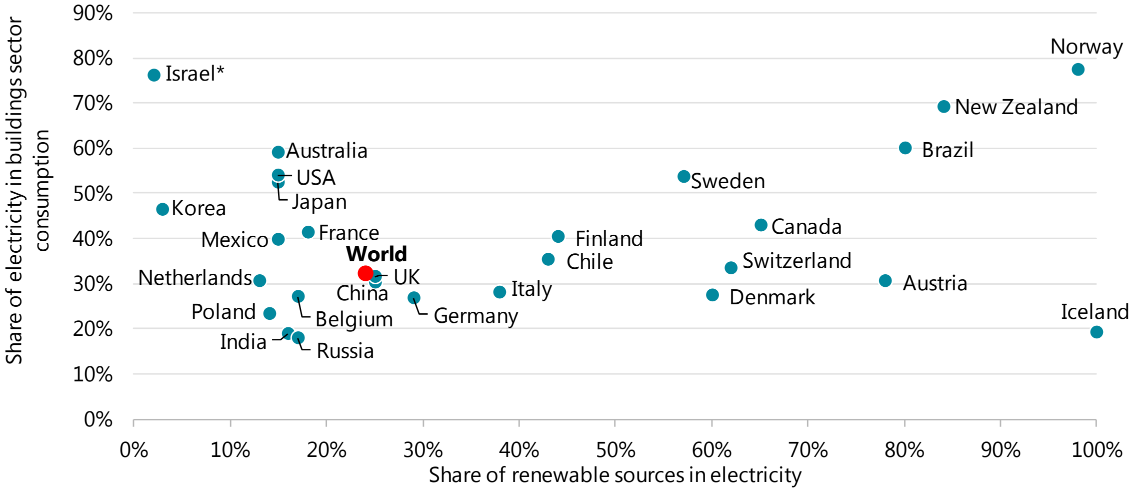


Sources: IEA (2019a), *World Energy Statistics and Balances 2019* (database), www.iea.org/statistics/; IEA (forthcoming), *World Energy Outlook 2019*.

With the electrification of heat in buildings (through electric heaters and heat pumps) and increasing shares of renewables in electricity generation, renewable electricity has been the largest contributor to renewable heat uptake in buildings in the past decade in absolute terms. This trend is set to continue, with an additional 1.1 EJ of renewable electricity consumption expected over 2019-24, amounting to 42% of global renewables expansion in buildings – more than double bioenergy growth. Indeed, growth opportunities exist in many countries to electrify buildings heat uses, to expand the share of renewables in power generation, or both (Figure 4.7).

The European Union and China lead growth, accounting together for half of increased consumption, followed by the United States and Brazil. Drivers vary across regions, however: in both the **European Union** and the **United States**, further renewables penetration in the electricity generation portfolios explains more than 80% of the anticipated growth, whereas in **China**, where the number of electric-heating users rose by more than 1.5 million in 2018 (IEA, 2019b), over half of the increase results from the electrification of building heat (Figure 4.8). In **Brazil**, all factors – i.e. a higher share of renewables in the generation mix, heat electrification, and overall growth in buildings sector consumption – contribute to the projected rise in renewable electricity consumption. In the rest of the world, upstream uptake of renewables in the power sector is the main driver, explaining about half of the growth.

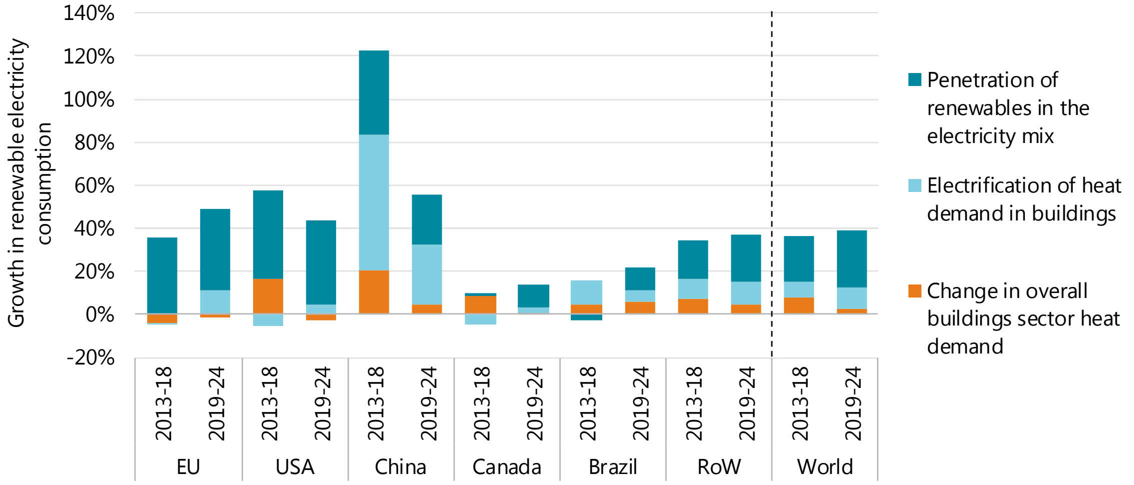
Figure 4.7. Share of electricity in buildings sector final energy consumption and share of renewables in electricity for selected countries, 2017



* The statistical data for Israel are supplied by and under the responsibility of the relevant Israeli authorities. The use of such data by the IEA/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.

Source: IEA (2019a), *World Energy Statistics and Balances 2019* (database), www.iea.org/statistics/.

Figure 4.8. Factors contributing to renewable electricity growth in buildings, 2013-18 and 2019-24



Sources: Based on IEA (2019a), *World Energy Statistics and Balances 2019* (database), www.iea.org/statistics/; IEA (forthcoming), *World Energy Outlook 2019*.

Heat pumps

The most common heat pump applications involve residential and commercial buildings, but interest is also growing in large-scale heat pump integration in modern district heating networks (see chapter 5) and in industry. Meeting less than 3% of heating needs in buildings globally, electric heat pumps continue to represent a small share of heating equipment, as more than three-quarters of sales globally were for fossil fuel or conventional electric technologies in 2018 (IEA, 2019c). While the exact size of the global market is still unknown,[28] heat pump sales have been accelerating in recent years, although a share of these corresponds to reversible units that are used primarily for air conditioning (Zhao, Gaob and Song, 2017). **China** has the largest share with approximately three-quarters of annual sales, followed by Japan, the United States and the European Union. **European Union** sales exceeded 1.2 million units in 2018 – a 12% increase from the previous year – with France, Italy, Spain, Sweden and Germany together accounting for two-thirds of the total, bringing the cumulative number of installations to nearly 12 million (EHPA,2019). Scandinavian countries display the highest penetration, with 47% of households equipped with heat pumps in Norway, 37% in Sweden and 30% in Finland.

Air-source heat pumps (ASHPs), which include reversible air-air and air-water systems[29], largely dominate the global market because their investment costs are lower and they are more flexible in terms of building compatibility and space requirements. Plus, because solar photovoltaic (PV) generation and cooling demand operate in a complementary fashion, the potential to use reversible heat pumps in combination with solar PV to meet anticipated

[28] Global market data on air-air heat pumps are unavailable. Assessing the scale of the global heat pump market is challenging due to lack of data and inconsistencies among existing datasets. This analysis draws upon data from BSRIA (2018), AHRI (2019), EHPA (2019), and Eurostat SHARES (2018). It focuses on heat pumps used for heating and excludes air conditioning units used only for cooling.

[29] Heat pump technologies are generally categorised by the heat source and heat sink medium used (e.g. air, water or the ground).

cooling demand growth is promising (IEA, 2018b). Despite the higher upfront cost associated with borehole drilling, ground-source heat pumps (GSHPs) make up most of the remaining installations, and continued deployment is expected, especially in Sweden, Germany and China, because of their higher achievable efficiency.

In addition to technical improvements, policy support – in the form of financial incentives, regulations and energy performance standards for new buildings and renovations – has been central to rapid heat pump deployment in recent years. In China, heat pump deployment has been promoted through subsidies introduced under the Air Pollution Prevention and Control Action Plan that encourages a shift away from coal-fired boilers. In Japan the Energy Conservation Plan provides financial support for investment. In Europe, tax credits for installation and performance standards for new buildings in France, energy savings grants and tax rebates in Italy, and investment grants in Germany were all important drivers. Support schemes to phase out oil boilers in Finland, sustained carbon tax rates in Sweden, and the banning of gas grid connections for new buildings in the Netherlands have also boosted heat pump deployment. In the United Kingdom, however, the extensiveness of the gas network makes heat pumps less economically competitive with traditional gas boilers, but RHI subsidies have contributed to the installation of 22 000 units each year for the past two years, especially in off-gas-grid buildings.

Among the various challenges to heat pump adoption are the availability of qualified installers, noise control and consumer inertia. The main obstacle, however, is still cost-competitiveness, which depends on a combination of factors including relative fuel prices[30] (electricity versus gas), climate (outdoor temperature) and building size and suitability.

Building insulation and heat distribution systems affect heat pump efficiency particularly strongly. In some cases, building renovations may be needed to improve heat pump compatibility, which raises upfront costs that are already high compared with alternative options.

Emerging business models, such as leasing or solutions proposed by energy service companies (ESCOs), can help overcome the barrier of high investment costs by providing alternative financing options. Sustained policy support in the form of economic incentives and regulations will, however, remain essential for market growth. In this respect, analysis of the provisional NECPs submitted following the 2018 revision of the RED suggests continued support in almost all European countries.

Box 4.1. Indirect renewable energy consumption from heat pumps

Heat pumps provide space heating, water heating or both, and reversible heat pumps can be used for both heating and cooling. Heat pumps work by extracting ambient heat from one environment (the heat source) and transferring it to another (the heat sink), generally by using a compressor to circulate a refrigerant fluid through a vapour-compression refrigeration cycle. Under favourable conditions, the amount of thermal energy transferred can be significantly higher (three to five

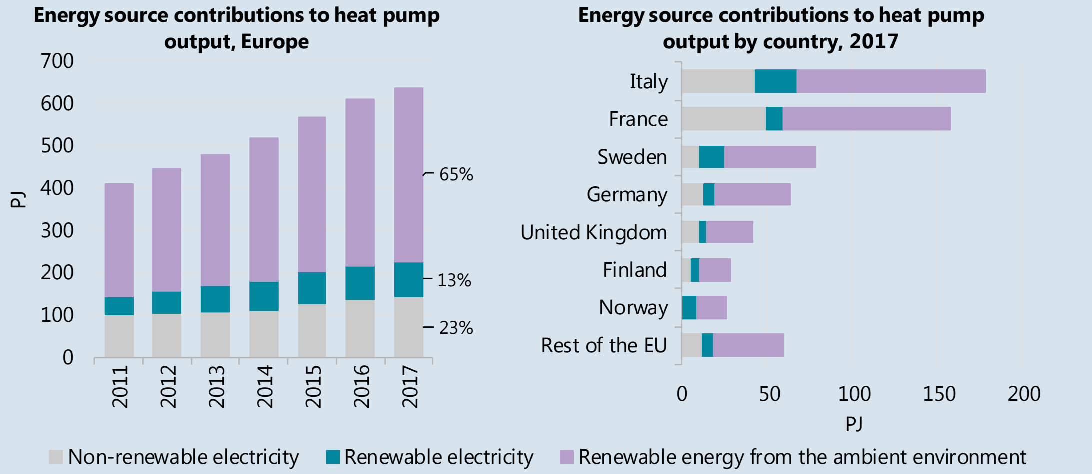
[30] It is worth noting that heat pumps and renewables are not always competing on equal terms, as fossil fuels are still subsidised in many countries (IEA, 2018c).

times) than the energy used to drive the compressor, resulting in high device efficiency for heating purposes. This ratio between useful heat delivered and energy input defines a heat pump's coefficient of performance (COP) and its yearly average value, the seasonal performance factor (SPF), both of which reflect system efficiency. As efficiency decreases significantly when the difference in temperature between the heat sink and the heat source increases, heat pump effectiveness depends on both the climate and a building's insulation and heat distribution system. In the European Union, ambient thermal energy extracted from a heat pump source is credited as renewable, provided the heat pump meets a minimum SPF value.

In addition to harnessing ambient heat, electrically driven heat pumps also consume renewable energy indirectly through electricity, so the greater the share of renewables in electricity generation, the more the heat pump contributes to heat decarbonisation. The figure below provides rough estimates of renewable and non-renewable electricity consumed by heat pumps in Europe, based on installed capacity, load factors, performance data[31] and average national shares of renewable sources in electricity generation.[32]

In 2017, renewables accounted for more than a third of electricity consumed by heat pumps in the European Union. As the share of variable renewables in the power mix increases, this potentially dispatchable load from heat pumps, which, for instance, amounts to more than 5% of total electricity consumption in Sweden, could also contribute to the integration of variable renewables if it is utilised for demand-response (IEA, 2019d).

Energy source contributions to useful heat provided by heat pumps in Europe



Sources: IEA analysis based on data from Eurostat (2018), *SHARES 2017*; IEA (2019a), *World Energy Statistics and Balances 2019* (database), www.iea.org/statistics/.

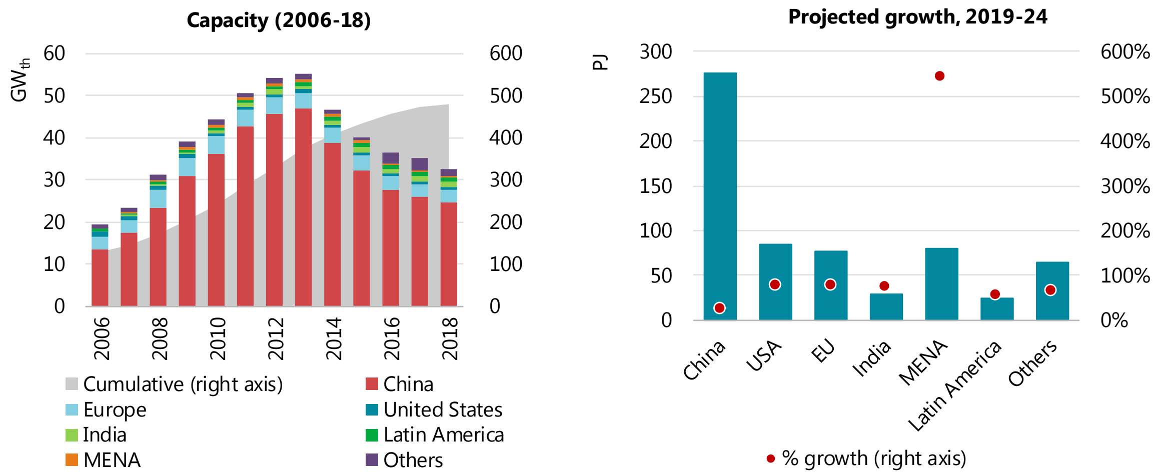
[31] Calculation based on the European SHARES database.

[32] More accurate results could be obtained using actual hourly renewable generation data and heat pump load curves, but these data were not available at the EU scale.

Solar thermal

In 2018, solar thermal systems provided about 1.51 EJ (420 TWh) of space and water heating to the buildings sector, 4.8% more than in 2017. However, gross annual capacity additions fell 3.9% to 33.3 gigawatts thermal (GW_{th}), registering a decline for the fifth year in row. This decline is attributed mostly to **China**: although it still dominates the global market with 74% of gross additions (Figure 4.9), reduced construction activities for new buildings, market saturation and competition with electric systems (e.g. heat pumps), as well as the phaseout of incentives, are curtailing demand for residential solar water heaters (the core sales segment). With system replacement accounting for a substantial part of gross additions, cumulative global operating capacity increased by just 1.4% (6.5 GW_{th}) in 2018, reaching an estimated 480 GW_{th} (686 million square metres [m^2]) at the end of the year (IEA SHC, 2019). As a result, solar PV overtook solar thermal for the first time in terms of cumulative installed capacity, with 495 gigawatts electrical (GW_e) generating 550 TWh of electricity in 2018.

Figure 4.9. Solar themal capacity and buildings sector consumption growth



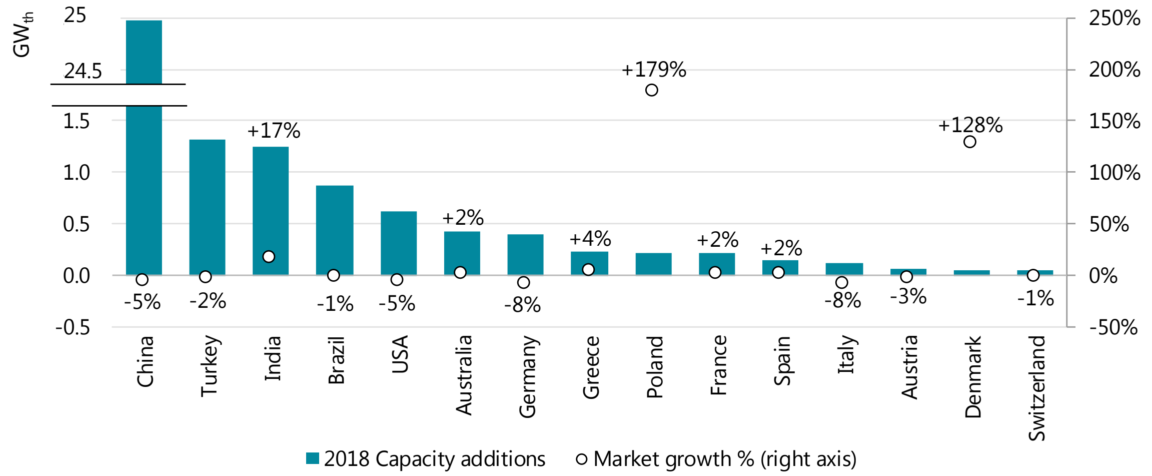
Note: MENA= Middle East and North Africa.

Sources: Based on IEA SHC (2019), *Solar Heat Worldwide 2019*; IEA (2019a), *World Energy Statistics and Balances 2019* (database), www.iea.org/statistics/; IEA (forthcoming), *World Energy Outlook 2019*.

Still leading in new installed capacity after China are Turkey, India and Brazil, followed by the United States, Australia and Germany (Figure 4.10). In Australia, new capacity expanded 2% in 2018 with the support of national renewable energy targets and subsidies under the Solar Communities Program. However, a range of barriers hindered development in other key markets:

- unfavourable economic conditions and the issuance of few construction permits in Turkey
- slowdown in the implementation of a social housing programme in Brazil
- low fossil fuel prices in the United States
- slow heating system turnover as well as competition with heat pumps in Germany.

Figure 4.10. Solar thermal capacity additions and market growth for selected countries among the top 20, 2018



Sources: IEA SHC (2019), *Solar Heat Worldwide 2019;* REN21 (2019a), *Renewables 2019 Global Status Report*.

In India, despite 17% growth in capacity from 2017, solar thermal potential remains untapped due to a lack of new policies. The EU solar thermal market expanded 8% (EurObserv'ER, 2019), with notable market growth in Poland owing to municipal tenders and support for municipalities under the emissions reduction programme. Markets also expanded in Denmark, Greece, Spain and France, as well as in Mexico and South Africa (IEA SHC, 2019).

Domestic water heating is by far the largest end-use, accounting for almost 95% of solar thermal energy consumption (the rest being for swimming pools and, to a lesser extent, space heating), with more than two-thirds of consumption from small-scale systems for single-family homes. Deployment of large-scale systems for large residential, commercial and public buildings has also increased to make up about half of newly installed capacity. District heating applications are likewise expanding, although they still represent less than 1% of installed capacity (1.2 GW_{th}). Denmark continues to lead the way in this area, with 117 systems connected to district heating for 0.96 GW_{th} of installed capacity at the end of 2018.

Box 4.2. Recent market trends in solar thermal technologies

Vacuum tube collectors still made up 72% of global capacity added in 2017, reflecting high market shares in China and India. The share of **flat plate systems**, which are dominant in European countries, expanded to 24%, partly owing to rising demand for the façade and balcony-integrated applications for which they are preferred; in some regions, however, rising copper and glass prices have recently weakened their economic attractiveness. **Unglazed collectors** made up most of remaining sales, essentially in the United States, Brazil and Australia. While still a niche market, **integrated photovoltaic-thermal (PVT)** collectors continue to develop, with total cumulative thermal capacity of 524 megawatts thermal (MWth) (1.1 million m2) and nominal PV power of 178 megawatts peak (MWp) installed worldwide at the end of 2018, two-thirds of which are in France and Korea (IEA SHC, 2019).

Thermosyphon systems, which are the most common in warm climates and generally cost less than pumped ones, make up more than three-quarters of all solar thermal systems worldwide, and their share is increasing. Company portfolios and locations are among the primary determinants of business developments in solar thermal technologies.

Global annual solar thermal energy consumption in buildings is anticipated to increase more than 40% (+620 PJ) to make up 2.2% of total buildings sector heat consumption in 2024. With solar thermal expansion supported by current government targets to 2020 as well as by incentives aimed at controlling air pollution under the 13th FYP, **China** is still expected to account for more than 40% of this growth (Figure 4.10). The next-largest increases in solar energy consumption are in the **United States** (+77%) and the **European Union** (+76%; particularly in France, Italy and Germany, which together account for half of EU growth), followed by **Middle Eastern** and **North African** countries (+82 PJ), for which consumption increases more than five-fold. Significant acceleration is also expected in **India**, **Brazil** and **Mexico,** which together add another 51 PJ of solar thermal consumption in the buildings sector by 2024.

Geothermal

Meeting about 0.5% of global heat demand, direct geothermal,[33] although on the rise, is currently the smallest renewable heat source used in buildings. Deployment of geothermal systems remains confined to a limited number of countries, with China and Turkey alone accounting for about 80% of global geothermal heat consumption in 2017 and responsible for most of the growth in recent years. Although accounting for less than 1% of global consumption, Iceland's unique market stands out because geothermal energy meets the majority of heat demand.

Bathing and space heating (via district heating) are the most prevalent applications globally, representing almost 80% of both direct-use capacity and consumption, with the remainder dedicated mainly to agriculture (e.g. greenhouse heating, aquaculture and drying), and marginally to industrial processes (4%) (Lund and Boyd, 2015). New Zealand is an exception, however, with industry responsible for around 60% of direct geothermal consumption, particularly for the pulp/paper and textile industries.

Worldwide installed thermal capacity expanded by an estimated 1.4 GW_{th} in 2018, totalling 26 GW_{th} at the end of the year. **China** was an important contributor to this growth, and air pollution concerns are expected to stimulate continued development of geothermal district heating throughout the outlook period. Although relatively limited in absolute terms, **Europe** currently has one of the most active markets, with a number of ongoing projects for heating and cooling to be commissioned by 2025 (Table 4.3). As a result, direct geothermal energy consumption in the European Union is projected to increase almost 270% during 2019-24, with district heating remaining a key application. Policy support in the form of risk guarantees (available in France and the Netherlands) or investment grants (available in Poland) can help mitigate the investment risks associated with high upfront costs and uncertain drilling operation outcomes. The adoption in 2018 of the EU Climate and Energy Package for 2030 is expected to encourage future geothermal deployment.

[33] The use of geothermal ground source heat pumps is not included in this section.

Table 4.3. Geothermal installed capacity and ongoing projects for heating and cooling, selected countries

Country	Number of systems installed in 2018	Heating and cooling capacity (MW_{th})	Ongoing projects to be commissioned by 2025	Estimated ongoing capacity additions to be commissioned by 2025 (MW_{th})	Corresponding growth in capacity additions by 2025
France	74	586	16	160	+27%
Germany	33	336	34	952	+283%
Hungary	25	254	12	215	+85%
Italy	22	160	16	273	+171%
Netherlands	21	208	18	277	+133%
Poland	6	75	15	215	+288%

Note: Capacity additions for ongoing projects are estimates, as geothermal project capacities remain uncertain until initial drilling has been undertaken.

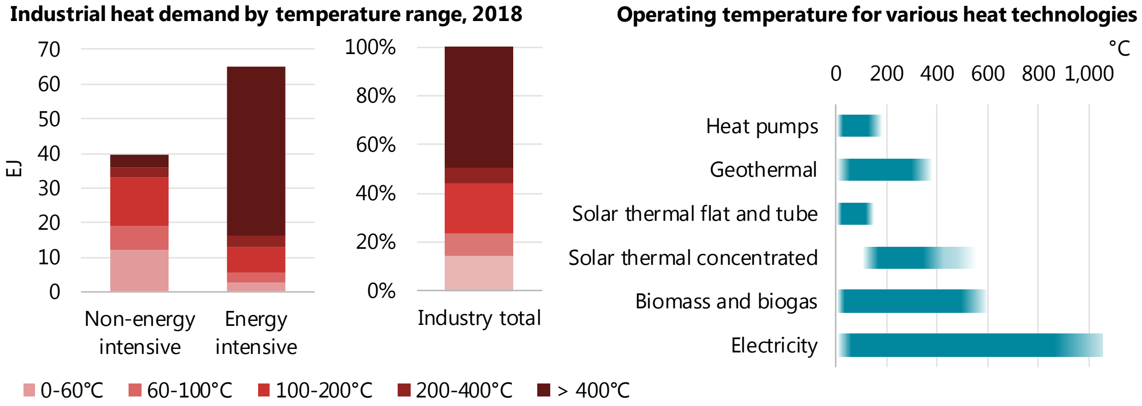
Source: EGEC Geothermal (2019), NECPs – Country fiches on geothermal energy market potential to 2030.

Industry

Industrial process heat refers to the thermal energy used in manufacturing processes for material transformation and chemical reactions. In 2018, heat used in industry accounted for 25% (105 EJ) of global final energy consumption and was responsible for 23% of global energy-related CO_2 emissions. China currently accounts for over one-third, followed by the United States, India and the European Union, which together make up another quarter. Heat demand in industry is anticipated to rise almost 9% (+9 EJ) globally during 2019-24.

The iron and steel, cement, and chemical subsectors – for which coal and, to a lesser extent, natural gas remain the main sources for heat production – are the largest heat consumers, followed by aluminium, food and tobacco, and pulp and paper. Together, these subsectors account for over 70% of total industrial heat consumption. Renewables meet only 10% of the sector demand, with the largest contribution from biomass and waste.

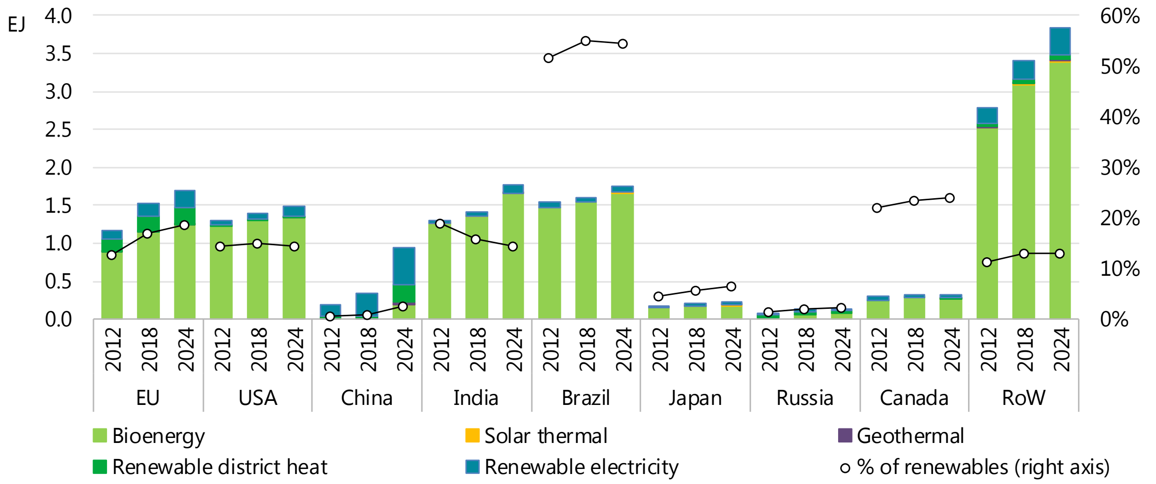
Figure 4.11. Industrial heat demand by temperature range and heat technology suitability



Sources: IEA (forthcoming), *World Energy Outlook 2019* (left figure); IEA SHC Task 49 (2019a), "Process heat collectors: State of the art and available medium temperature collectors"; BNEF (2019), *Industrial Heat: Deep Decarbonization Opportunities* (right figure).

Given the diversity of production processes, industrial heat demand is not homogeneous and encompasses a wide variety of temperature requirements, which imposes technical limitations on fuel options (Figure 4.11). Indeed, while numerous renewable technologies can provide low-temperature heat (<150°C), fewer options are suitable for medium- and high-temperature processes, which currently account for 70% of industrial heat demand. Furthermore, high levels of process integration can make fuel substitution more challenging, especially when the heating system has a secondary purpose (e.g. pressure control) or when the fuel also acts as a feedstock (e.g. coal in iron production and steelmaking). Yet, there is significant potential for further direct and indirect renewable heat use, which, along with energy efficiency improvements, will be crucial to reduce industrial CO_2 emissions.

Figure 4.12. Historical and projected renewable heat consumption trends in industry for selected regions



Note: Baseline bioenergy data for China may not capture all ongoing consumption due to data collection challenges.

Sources: IEA (2019a), *World Energy Statistics and Balances 2019* (database), www.iea.org/statistics/; IEA (forthcoming), *World Energy Outlook 2019*.

Bioenergy

The majority (86%) of renewable heat used in industry is bioenergy. Its contribution is projected to increase from 8.9 EJ in 2018 to 10 EJ in 2024 (+12%); however, its share in industrial heat consumption remains under 9% because global industrial heat demand is expected to grow strongly (Figure 4.12).

Owing to the extensive use of bagasse in its sugar, ethanol and food industries, **India** is expected to nearly catch up with **Brazil** as the largest industrial bioenergy consumer by 2024, whereas the **United States**, using considerable bioenergy in its pulp and paper industry, remains the third-largest consumer. The largest absolute increases in industrial bioenergy heat consumption are anticipated to come from India (+296 PJ) and China (+195 PJ), particularly in the cement industry for the latter, with notable expansion in the European Union as well (+80PJ).

Current and potential bioenergy uses vary significantly across subsectors. While it is well suited to provide the temperature, pressure and quantity of heat and steam required by many industrial processes, it is used mainly in industries that produce biomass waste and residues on-site, i.e. pulp and paper, wood products, food and tobacco, and sugar and ethanol.[34]

The **pulp and paper subsector** already exploits its biomass resources extensively for steam, heat and electricity production through co-generation. As such, bioenergy provides just under 40% of the subsector's total energy consumed globally. Heat demand for pulp and paper is expected to remain stable over 2019-24, as higher demand for sanitary tissue and packaging materials for online commerce is almost offset by declining paper and print market demand due to greater digitalisation. Greater use of recovered fibres also reduces the availability of biomass residues. Limited bioenergy growth (+4%) is thus foreseen for the sector, although bioenergy output could be raised by improving the energy efficiency of current recovery boilers and shifting to best available technologies.[35]

Bioenergy also covers a notable portion of energy demand in the **food and tobacco** subsector (18% in 2016) and an even greater share in the **sugar and ethanol industry.** In the latter, however, potential to scale up the use of sugar cane for process heat and electricity co-generation for on-site use and export remains largely untapped. Transitioning to higher-efficiency co-generation plants fuelled by bagasse, optimising the collection and use of sugar cane straw, and using new sugar cane varieties such as "energy cane" with higher fibre content could increase the bioenergy surplus considerably.

Bioenergy use is far less common in industries that do not produce biomass waste and residues on-site, as fuel supply chains would need to be developed. For instance, the share of bioenergy used in the **aluminium** as well as in the **chemical and petrochemical** industries is anticipated to easily remain below 1% of demand over the outlook period. This is also the case for the **iron and steel** industry, with bioenergy use restricted almost exclusively to Brazil (98%), where biomass is transformed into charcoal to be used in the blast furnace reduction process, meeting approximately one-quarter of the country's iron and steel energy demand. However, given the scale of forestry plantations required, the associated sustainability considerations[36] and bioenergy's cost-competitiveness with coke as a reducing agent, this practice is not expected to expand extensively to other countries. If switching to renewable fuels for iron and steel production appears difficult in the short term, increasing waste heat recovery and using recycled scrap steel in electric arc furnaces can help decarbonise the sector.

In the **cement industry**, which is the third-largest industrial energy consumer and CO_2 emitter, biomass and waste-based fuels[37] together met only 6% of global thermal energy demand in 2017. This share, which is expected to increase in coming years, varies greatly across regions, from less than 2% in China (which was responsible for 58% of global cement

[34] For instance, bioenergy accounted for more than 30% of final energy consumed globally in the pulp, paper and print, and the wood and wood products industries in 2016.

[35] Modern high-efficiency chemical pulp mills are capable of generating excess surplus electricity and heat for export to the grid and to district networks, offering another revenue stream (IEA, 2018b).

[36] The biomass source used for charcoal production has been the subject of scrutiny, resulting in initiatives to replace unsustainable biomass from native forests with that from sustainably managed forestry plantations.

[37] Some wastes used as fuels in this sector can be partially or totally biogenic; for instance, typical wastes include non-recyclable plastics, mixed industrial waste (including lime sludge from the paper industry), discarded tyres, waste oils and solvents, wastewater and sewage sludge.

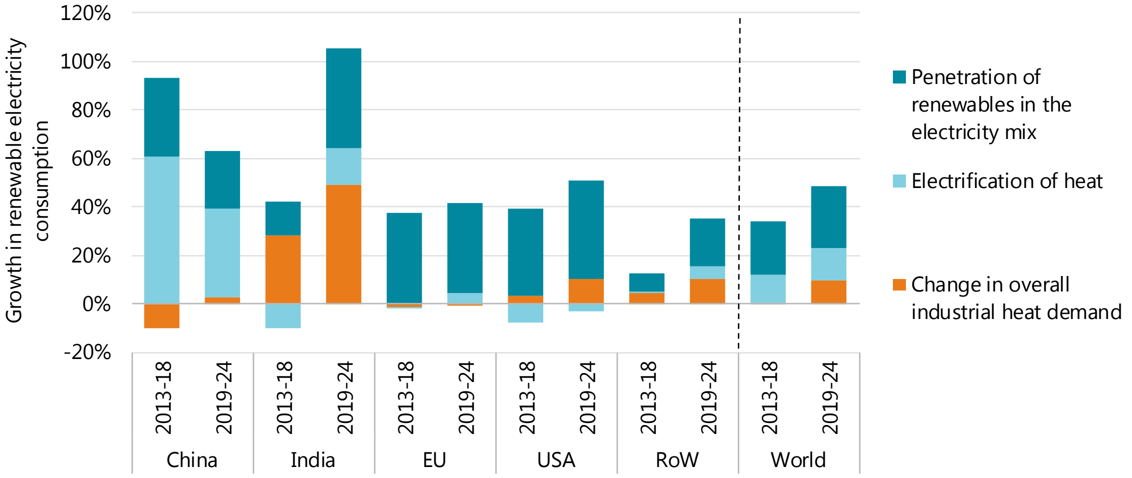
production in 2018) to about 25% in the European Union (producing 4% of the world's cement), with penetration rates as high as 40% in France and the United Kingdom, and 65% in Germany (WBCSD Cement, 2016). Waste-based fuels, making up two-thirds of these "alternative fuels", have the greatest potential to displace fossil fuels and also offer an alternative to landfill disposal and basic incineration. Significant developments are anticipated in China, where bioenergy consumption in the cement subsector is expected to expand more than fourfold (+100 PJ) during 2019-24 in response to pressing waste management and air quality concerns related to coal use. Greater alternative fuel uptake in the cement industry can be facilitated by co-ordinating supplies of sustainably sourced biomass across sectors to enable cost-competitive access for the cement sector, and by implementing stringent waste management policies (IEA, 2018d). In addition, as cement demand is essentially driven by the construction sector, a shift in construction practices and materials – from cement and steel to renewables and biosourced materials such as wood, which acts as a carbon sink when growing – could reduce cement demand and thus cement industry CO_2 emissions, while also providing carbon storage (within infrastructures).

Renewable electricity for industrial heat

Renewable electricity is the second-largest renewable energy source in industry, although it met less than 1% of global industrial heat demand in 2018. Worldwide consumption increased 34% in the last six years, and it is projected to continue rising at the same pace over the outlook period. **China**, which accounted for 29% of the world total in 2018, remains the primary industrial consumer of renewable electricity, with more than 60% growth over 2019-24 anticipated from both electrification of industrial heat and a greater share of renewables in the electricity mix (Figure 4.13). This latter factor is the main reason for growth in the **European Union** (+68 PJ) and the **United States** (+38 PJ), which together continue to account for one-quarter of global industrial renewable electricity consumption over the next six years. On a single-country basis, **India** demonstrates the second-largest absolute growth in renewable electricity consumption (+53 PJ) after China (+184 PJ), as its industrial heat demand rises dramatically (+39%) over the outlook period, especially for steelmaking.

With expanding shares of renewables in electricity generation, electrification is a promising option for industrial decarbonisation (IEA, 2017a). Yet, electrification of heat currently results more from economic and technical considerations than from policy support (IEA, 2017b). A significant portion of industrial electricity consumption for heat is concentrated in the iron and steel industry as well as in aluminium because electricity is used for arc furnaces to melt scrap metal and for high-temperature electrolysis (in aluminium smelting). Given the increasing share of renewables in electricity generation, recycling and downcycling can very effectively decarbonise these sectors by raising the proportion of electricity used in process heat and enabling significant energy savings (BNEF, 2019). Heat pump use for low-temperature needs is also anticipated to expand in less energy-intensive industries.

Figure 4.13. Factors contributing to higher renewable electricity use in industry in selected regions, 2013-18 and 2019-24



Sources: IEA analysis based on IEA (2019a), *World Energy Statistics and Balances 2019* (database), www.iea.org/statistics/; IEA (forthcoming), *World Energy Outlook 2019*.

Solar heat for industrial processes

Although its current share in global industrial heat demand is still negligible (less than 0.02%), solar heat for industrial processes (SHIP) continues to be an expanding niche market. In 2018, at least 108 new systems (about 37.6 MW_{th}) were commissioned, bringing the worldwide installed collector area to around 663 000 m² (+9%) and the corresponding capacity to 567 MW_{th} (+7%) at the end of the year. Not including Oman's exceptionally large Miraah plant dedicated to enhanced oil recovery (EOR), the first phase of which was constructed in 2017, this represents a 25% increase in annual installed collector area. China was responsible for more than half of the collector area additions, followed by Mexico (13%), France (10%) and India (7%) (IEA SHC, 2019).

Aside from large thermal EOR projects, SHIP expansion is expected to continue throughout the outlook period, with a 21% CAAGR globally leading to a more than threefold increase in industrial solar thermal energy consumption between 2019 and 2024. India, which has introduced capital subsidies for concentrated solar thermal systems until 2020, could lead this development with more than one-quarter of global projected growth, followed by the United States, the European Union, China, South Korea and Turkey.

Solar thermal energy is well suited to a number of industrial applications with low- to medium-temperature heat requirements. Most installed SHIP capacity is currently concentrated in the mining industry, with a small number of large-scale projects such as the Codelco Gabriela Mistral plant (32 MW_{th}) in Chile providing heat for copper mining, and the Miraah plant in Oman (100 MW_{th} of the planned 1 GW_{th} in operation) delivering steam for thermal EOR (IEA SHC Task 49, 2019b). The Belridge Solar project in California (850 MW_{th} planned), also dedicated to EOR, is expected to start operations in 2020. Most other SHIP applications supply the food and textile industries through small and medium-sized systems, but there is scope for greater use in other subsectors, e.g. the chemical industry. Agriculture also uses relatively small amounts of solar thermal energy, with 0.4 PJ consumed in 2018.

Untapped SHIP potential is vast, especially in regions with high direct irradiation where payback periods can be very competitive – sometimes shorter than for fossil fuel alternatives. Greater deployment, however, will depend not only on further cost reductions but – most importantly – on policy support, particularly to overcome the current lack of awareness and acceptance and to reduce investor uncertainty. Involving ESCOs could also be important to overcome relatively high upfront costs and reduce uncertainty for clients.

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5. Renewable energy trends to watch

Key questions

Whereas the previous chapters presented regional and technology forecasts for the electricity, transport and heat sectors, this one addresses ten questions for additional analysis of selected renewable technology and cost trends across various sectors.

- What are the trends for remunerating renewable electricity in the next five years?
- Is the ageing of renewable capacities during 2019-24 a concern?
- How have macroeconomic factors affected renewable capacity financing costs since 2015?
- Does security of supply drive key biofuel markets in Asia?
- What end uses will stimulate biogas production growth?
- Should grid integration be a concern for policy makers in countries with low wind and solar deployment?
- What will be the role of hydrogen in renewable energy deployment by 2024?
- Has energy efficiency helped EU countries reach renewable energy targets?
- How can district heating help decarbonise the heat sector by 2024?
- How big is the mineral resource footprint of renewable electricity development?

What are the trends for remunerating renewable electricity in the next five years?

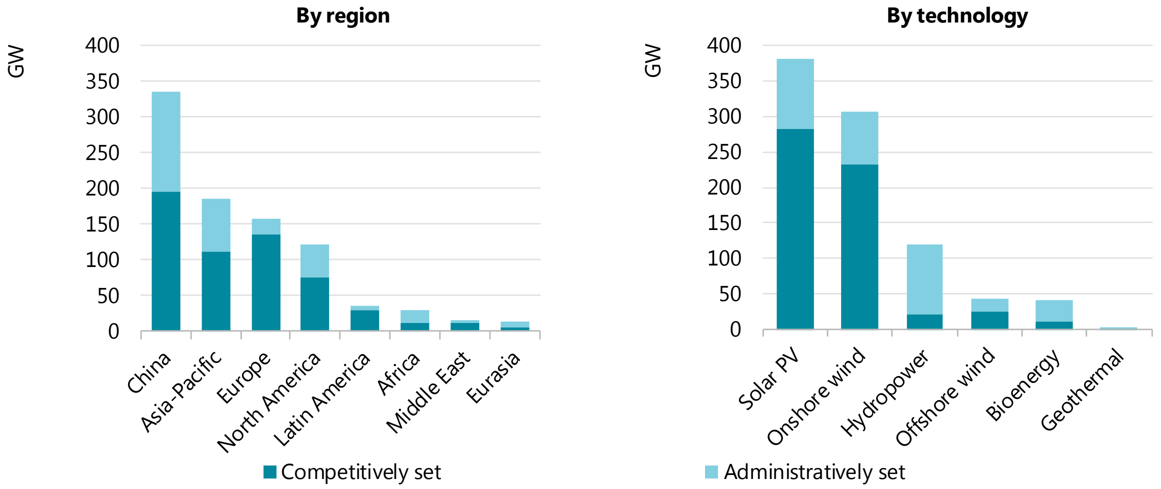
For utility-scale renewable electricity technologies, many countries are transitioning from support schemes based on administratively set tariffs to competitive auctions for long-term power purchase agreements (PPAs). If they are well designed, auctions create a beneficial situation for both governments and developers. For many governments, competition results in price reductions throughout the supply chain and lower total subsidy costs for renewables. For developers, PPAs provide long-term revenue certainty, which reduces project risks for capital-intensive renewable technologies such as wind and solar photovoltaic (PV).

Renewables 2019 expects that remuneration for almost two-thirds of all new utility-scale renewable capacity over the next five years will be competitively set (Figure 5.1). This is significantly higher than the *Renewables 2018* estimate of half of additions, mainly because the transition to competitive auctions for onshore wind and solar PV is happening more quickly than anticipated in the People's Republic of China ("China").

Competitively set remuneration therefore covers almost 75% of all wind and solar PV capacity to be commissioned during 2019-24. While the majority will be determined through government-organised auctions, a growing number of PPAs with large corporate buyers and utilities is also expected. For hydropower, though, administratively set tariffs will continue to stimulate development, as vertically integrated utilities are usually responsible for developing large-scale hydro projects for which the technology has a much longer lifespan and offers a range of services that are not rewarded through an auctioning scheme.

Furthermore, most hydropower expansion is expected in emerging and developing economies, where vertically integrated utilities predominate. For most bioenergy capacity, remuneration will be set administratively, as China remains the largest growth market owing to its feed-in tariff (FIT) system.

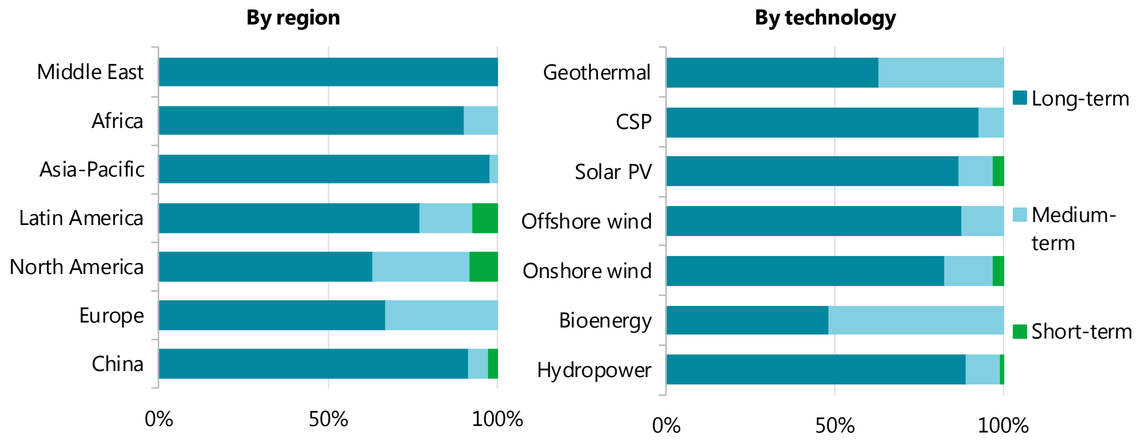
Figure 5.1. Utility-scale renewable capacity growth by remuneration type, 2019-24



Regional remuneration policy trends vary across markets. In the European Union, renewable capacity growth is driven mostly by competitive auctions after the European Commission's proposal to phase out FITs. In the United States, remuneration for wind and solar are usually set competitively through corporate or utility purchases, but projects also receive production and investment incentives (production tax credits [PTCs] and input tax credits [ITCs]) that are set administratively. Except for large-scale hydropower, most Latin American countries have adopted auctions schemes for all renewable technologies. In Africa, countries are switching from FITs to competitive auctions, but hydropower still dominates capacity growth and its remuneration is mostly set administratively.

Long-term contracts covering more than 75% of the economic lifetime of renewable projects dominate the forecast (Figure 5.2). However, government policies have begun to expose wind and solar PV to more market and price risks, as these technologies have matured and become more competitive with fossil fuel-based alternatives. Overall, wind and solar PV contracts are becoming shorter in most countries where electricity markets are partially or fully liberalised and competitive financing exists, such as North America and Europe. In these markets, some developers are switching to multiple revenue streams from corporate PPAs, auctions and merchant activities. Bioenergy-for-power contracts are usually shorter than those for other renewable technologies due to fuel cost variability.

Figure 5.2. Contract length for new capacity additions, 2019-24

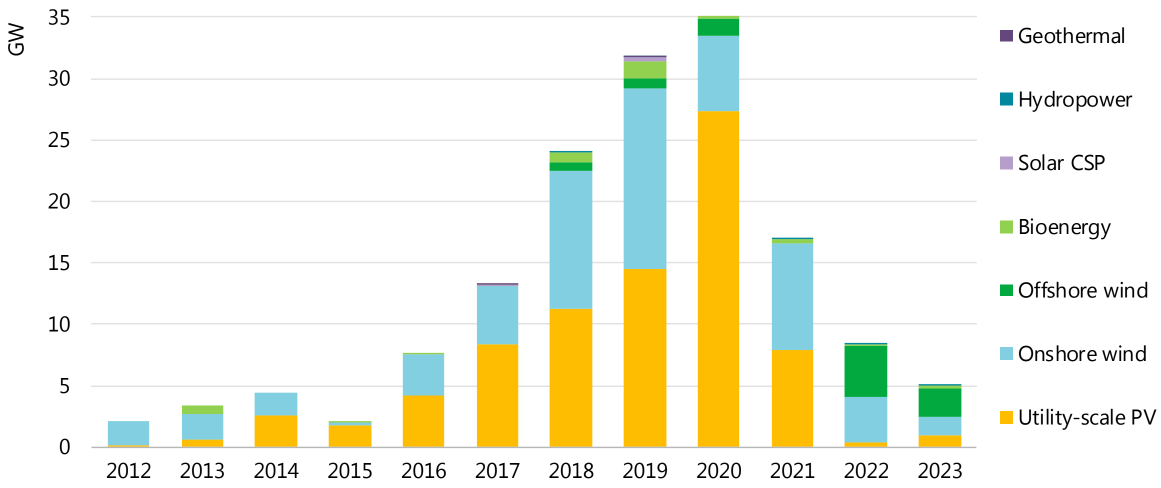


Notes: Long-term = contracts covering more than 75% of a project's lifetime; medium-term = 50%; short-term = less than 50%. The economic lifetime assumed for onshore and offshore wind is 25 years; 20 years for solar PV; 35 years for hydropower; 30 years for bioenergy; 25 years for concentrated solar power (CSP); and 20 years for geothermal.

Renewable energy auction trends

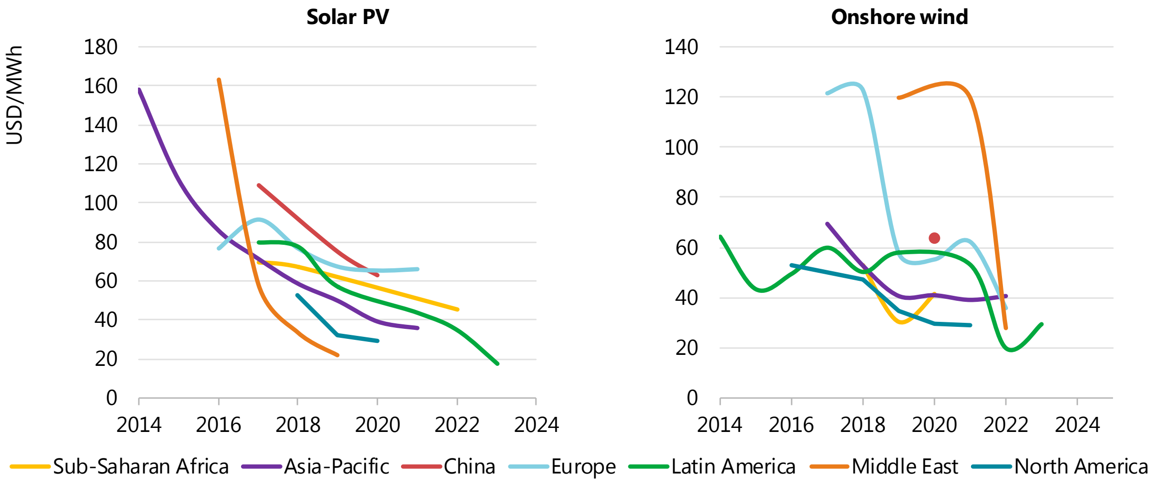
The International Energy Agency (IEA) renewable energy auction database tracks over 100 gigawatts (GW) of awarded renewable capacity expected to be commissioned (Figure 5.3). Solar PV and onshore wind projects together represent almost 90% of awarded auction capacity, with offshore wind, hydropower, bioenergy, geothermal and CSP accounting for the remainder. Capacity-weighted average auction prices for utility-scale solar PV projects decline from almost USD 160 per megawatt hour (/MWh) for those commissioned in 2014 to around USD 17/MWh for plants due to be commissioned in 2023 (Figure 5.4). For onshore wind, average auction prices drop from USD 65/MWh in 2014 to around USD 30/MWh in 2023. Asia, led by India and China, represents over half of auction-awarded capacity worldwide, influencing average prices for onshore wind and solar PV technology globally. The capacity-weighted average auction price in India for onshore wind is USD 40/MWh, and in China is around USD 60/MWh for projects to be commissioned in 2020.

Figure 5.3. Awarded auction capacities by technology and expected comissioning date



Trends in regional average auction prices for solar PV and wind technologies reflect different tender designs and financing mechanisms in various countries. For solar PV, prices fall rapidly in all regions, with projects in Latin America (Brazil), the Middle East (Saudi Arabia and the United Arab Emirates) and Europe (Portugal) having the lowest prices, and India's solar PV auctions dominating average prices in the Asia-Pacific region. For onshore wind, contract price fluctuations more visibly reflect technology maturity, auction design variations and resource availability. Brazil's latest energy auction produced the lowest price globally, followed by projects awarded in Saudi Arabia.

Figure 5.4. Average auction price by region and commissioning date



It is important to note that comparing auction prices could be misleading, as all countries and technologies have different resource potentials, financing conditions and auction designs. Furthermore, these auction prices are based on just a small portion of total capacity to be commissioned under competitively determined remuneration schemes, and prices reflected in auctions may be supplemented by additional revenues from corporate PPAs and merchant activities.

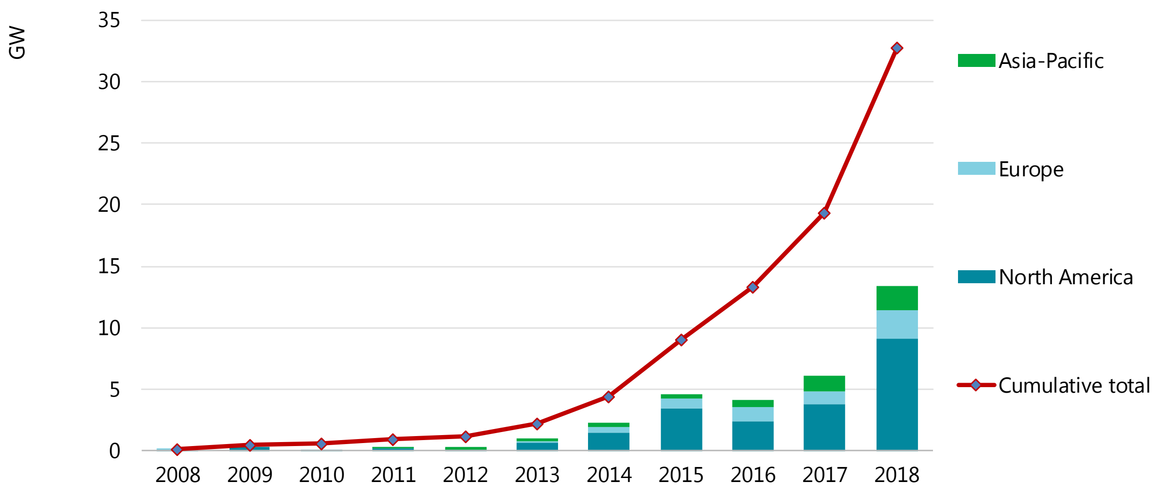
Corporate PPAs

The annual corporate PPA market showed a year-on-year (y-o-y) increase in 2018, with 33.5 GW of capacity awarded, compared with 27.4 GW the previous year (Figure 5.5). Over 30 GW of the capacity added in 2018 was from onshore wind and solar.

Corporate PPAs – bilateral contracts for power between consumers (typically large companies) and generators – are a procurement method that is relatively new to liberalised markets such as Europe, but they have been used for years in vertically integrated markets as a means for private developers to gain market entry when procurement options with state-owned utilities are limited, such as in the Middle East and North Africa. For example, the first wind projects in Morocco were developed under the corporate PPA business model.

In 2018, over 60% of global annual corporate PPAs were signed in the United States, mostly in deregulated markets such as those of the Electric Reliability Council of Texas (ERCOT), the Southwest Power Pool (SPP) and the Midcontinent Independent System Operator (MISO). Enterprises sign PPAs with wind and solar PV plants not only to meet their corporate clean energy goals, but to hedge against rising energy prices and volatility. The number of PPAs in Europe also doubled in 2018, led by Nordic countries and the United Kingdom, while Spain and Poland are expected to emerge as new markets in upcoming years. In the Asia-Pacific region, India leads the market despite a y-o-y slowdown due to challenges concerning additional grid charges, open-access issues and a sluggish large-scale rooftop market.

Figure 5.5. Wind and solar PV corporate PPAs by contract announcment date



Source: BNEF (2019), *Bloomberg Terminal*.

Similar to corporate PPAs, merchant projects have also been important in market-driven, deregulated parts of the United States, mostly in the ERCOT region in Texas, but also in the PJM, MISO, SPP and New York Independent System Operator (NYISO) areas. Merchant projects receive their revenue from short-term PPAs or spot markets, though the resulting price risk is typically hedged over a 10- to 12-year period (US DOE, 2018). In parts of Europe, such as Spain, project developers and investors are becoming increasingly comfortable with the energy price risk of merchant projects; however, most projects still rely on long-term guaranteed remuneration for at least part of the generation in order to attract low-cost financing.

Is the ageing of renewable capacities during 2019-24 a concern?

The cumulative capacity of renewable energy projects reaching the end of their commercial lifetimes over 2019-24 is expected to be significant in some countries and regions. One-third (446 GW) of current global hydropower capacity is already more than 40 years old, mostly in developed countries, and by 2024, 150 GW of onshore wind and 23 GW of solar PV capacity will have been in operation for 15 years or longer. These projects will be approaching the end of their long-term offtake agreements and facing rising maintenance costs.

For all ageing renewable technologies, project owners must assess the economics of repowering, refurbishing or decommissioning. While repowering and refurbishing may help countries achieve their renewable energy targets by extending the lifetimes or boosting the performance of existing assets, policy incentives and regulatory frameworks will ultimately determine the cost-effectiveness of these options.

Hydropower

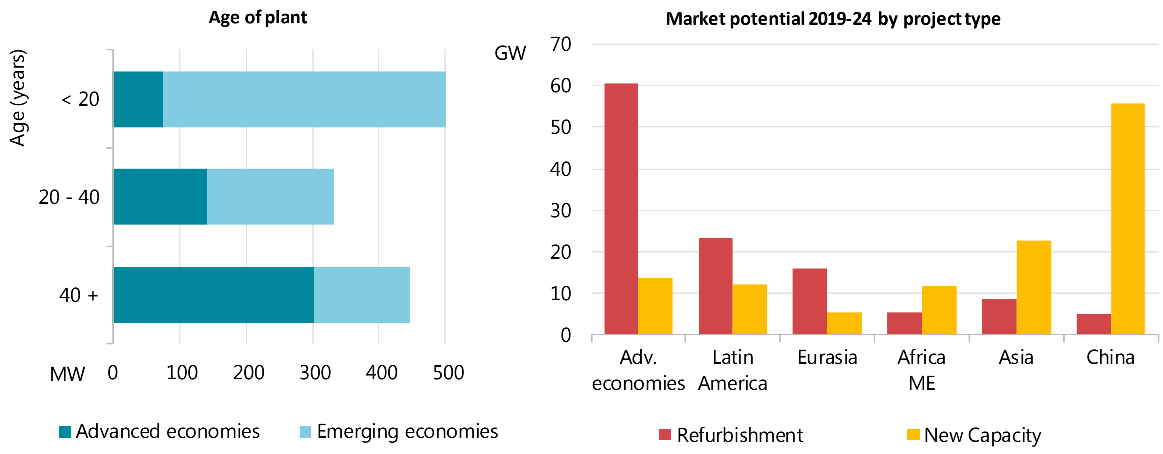
Hydropower is the oldest renewable electricity technology, with the earliest plants dating to the late 1800s. It is also one of the most complex renewable technologies, made up of many parts varying in size and function, each with its own specific lifespan.[38] While the civil structures of projects (i.e. dams, canals, powerhouses, penstocks, etc.) can last for more than one hundred years, the lifespans of the electro-mechanical parts (i.e. batteries, generators, turbines, etc.) can be anywhere from less than 20 years to 70 years, depending on performance level (World Bank, 2011). As these parts age, they can affect generation performance and, consequently, owner revenue. Therefore, rehabilitation work – such as preventive maintenance, equipment repairs and component replacements – are performed to maintain and, in some cases, increase output. Other reasons for rehabilitation are to adjust operating conditions to meet new market circumstances (such as increased demand for flexibility), to modernise components to reduce operation and maintenance costs, or to adapt to new water management and environmental needs.

Currently, one-third (446 GW) of global hydropower capacity is more than 40 years old, the stage at which the first major rehabilitation work is typically considered, usually related to the refurbishment of turbines. One-third of this ageing infrastructure is concentrated in just three countries: the United States, Canada and the Russian Federation ("Russia"). On a regional

[38] *Lifespan* refers to the service life of a component.

basis, however, fleet age varies significantly: in advanced economies, a majority (60%) of the fleet is over 40 years old (Figure 5.6), led by the United States, Canada, Japan, France, and Norway. In contrast, in many developing countries where hydropower development is more recent, only one-fifth of capacity is over the age of 40 (with half in Russia, Brazil, China, and India). The average fleet age[39] in sub-Saharan Africa and Southeast Asia is less than 30 years, and in China less than 20.

Figure 5.6. Age of global hydropower fleet and refurbishment potential over 2019-24



Note: ME = Middle East.

In the next six years, approximately 10% (120 GW) of current global capacity will cross the 40-year threshold at which the first major refurbishments are needed. This implies that half of the global hydropower market potential over the forecast period lies in opportunities to rehabilitate existing capacity. The largest amount of capacity approaching this age is in Europe, which accounts for one-fifth of refurbishment potential during 2019-24, followed by Canada, Brazil, the United States, Russia and Japan. In advanced economies, potential for refurbishment is significantly higher than for new-capacity plants (Figure 5.6) because their fleets are ageing and remaining economic potential for greenfield projects is limited. This is also the case in Brazil, where 10% of the fleet (14 GW) will cross the 40-year mark and only 6 GW of capacity is new. Conversely, capacity from new projects will make up the majority of the market in most emerging countries, especially in Asia and sub-Saharan Africa given the untapped potential.

Wind

The economic lifetime of wind turbines is usually around 20 years.[40] When wind turbines approach their final years of operation, developers usually consider three options: 1) decommissioning; 2) extending the life span of the existing turbine, usually by up to 25 years by refurbishing selected equipment; or 3) complete repowering of the plant by dismantling the original turbine and replacing with a new one, or partial repowering by

[39] Capacity-weighted average.

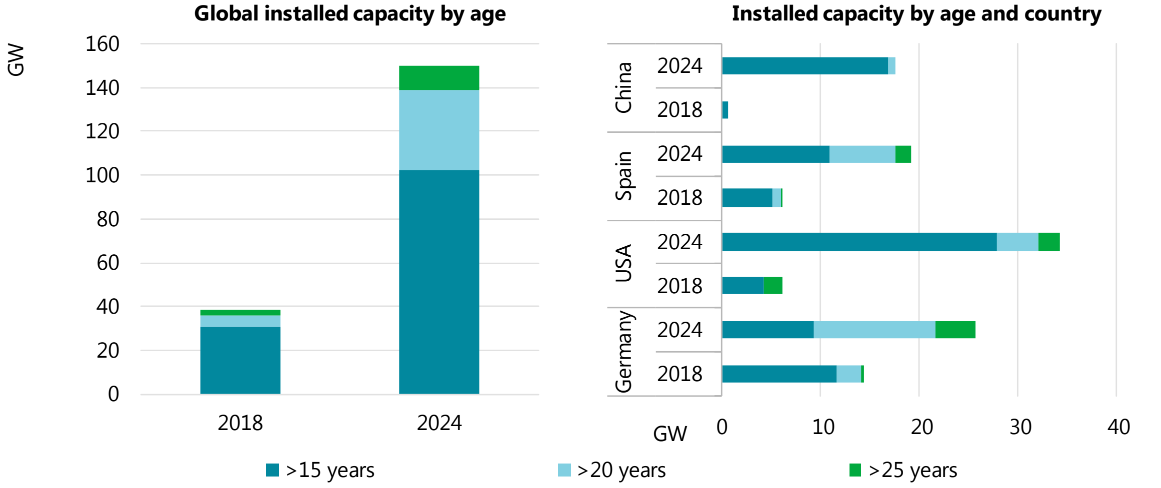
[40] 20 years for onshore wind turbines and up to 25 years for offshore turbines.

changing just the blades or the generator. Because ageing turbines are often at prime resource locations, they offer an opportunity for countries to meet renewable energy targets without additional land use because technology improvements mean that repowering can raise a plant's performance. In addition, new wind turbines are more system-friendly and can therefore contribute to grid integration.

Today, only 5 GW (1%) of the global wind fleet is 20 or more years old, but this proportion will increase more than sevenfold by 2024. To maintain the capacity and performance of the ageing fleet, refurbishments and repowering are required. Fortunately, given recent technology improvements, refurbishing and repowering onshore wind projects may be valid alternatives to decommissioning.

Developers may even consider repowering before the end of a turbine's operational lifetime because repair costs rise as the turbine ages. Operational and maintenance costs usually become substantial around 15 years of age, and today approximately 7% of global installed wind capacity (40 GW) has reached this age, most of it located in Germany, followed by Spain (Figure 5.7). By 2024, this amount will have increased threefold, such that 16% of global installed wind capacity (150 GW) will be older than 15 years, mainly in the United States, which overtakes Germany as the country with the largest ageing fleet.

Figure 5.7. Age of installed wind capacity, 2018 and 2024



Note: Based on cumulative installed capacity in a given year minus age. These estimates do not include repowering before the end of the commercial lifetime, accounting for approximately 2 GW.

Repowering decisions are also driven by other factors that affect the business case, such as the end of policy support. Project owners generally continue operations as long as maintenance costs do not exceed project revenues, but for most of today's capacity, this tipping point happens to correspond to the end of long-term remuneration contracts under former policy schemes. For example, in the European Union, former policy incentives provided mostly 20-year FIT contracts to wind developers. When these contracts end, developers will have to decide whether to extend the lifetime of the project or repower, but either of these investments carries a certain amount of risk, particularly in the absence of stable revenue streams.

Policy frameworks can therefore be critical to incentivise repowering and refurbishment, but policies that explicitly focus on repowering are rare. For instance, in the United States, tax incentives supported the partial repowering of over 1 300 turbines around 15 years old (totalling 2 GW) in 2017 (Table 5.1). The repowering procedure included installing longer turbine blades and 100 kilowatts (kW) more nameplate capacity (on average) per turbine (US DOE, 2018). Elsewhere, however, policy attention to repowering and refurbishing remains limited. This is expected to change in the Europe Union (at least), with the Renewable Energy Directive II requiring member states to specifically include repowering in their targets and policy frameworks from 2021 onwards, and to put simplified procedures in place for it (EU Directive [EU] 2018/2001, Article 16-6).

Table 5.1. Overview of wind repowering policies and incentives in selected countries

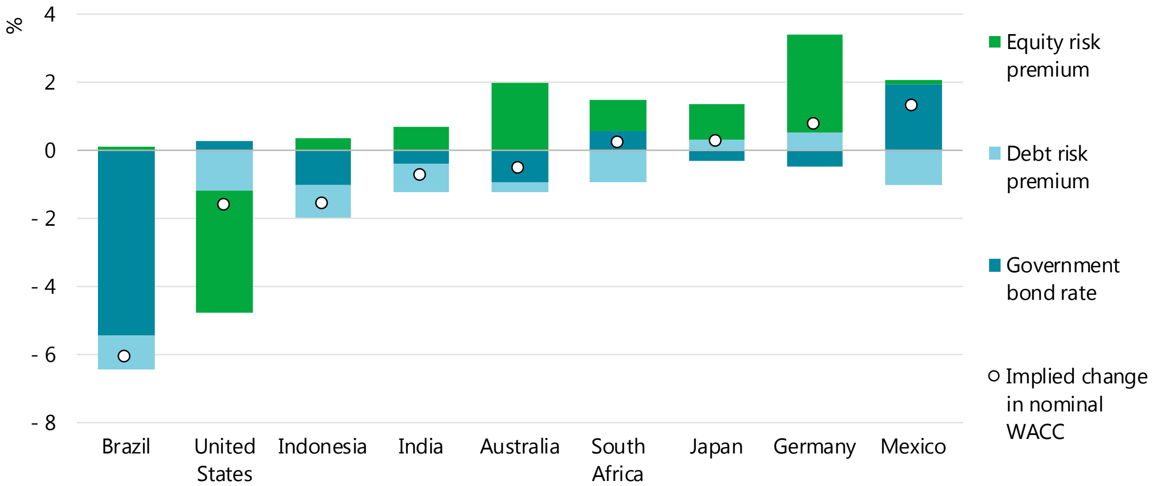
Country	Initial policy support	Policies for projects reaching end of remuneration period	Impact
USA	10-year PTC, plus long-term offtake	Partial and full repowering can requalify for 10-year PTC, which will phase out in 2020.	2 GW of partial repowering in 2017 (US DOE, 2017).
Germany	20-year FIT	No explicit incentives beyond 20 years; ageing projects must compete with new ones for support in auctions.	Expected repowering of 0.7 GW of the 2.1 GW reaching the end of FIT remuneration by 2020 (Quentin, Sudhaus and Endell, 2018).
Spain	20-year FIT reduced to 85%, capped at 2 600 hours/year	No incentives beyond 20 years.	Repowering of a few individual projects.
Italy	20-year FIT	Financial incentives through tenders for refurbishment and repowering; support scheme capped at a certain percentage of the full tariff for each option.	Not available.
China	20-year FIT	No incentives or policies.	Not available.

In addition to economics, non-economic factors such as expiration of land leases or building permits are an important consideration for repowering or lifetime extensions (WindEurope, 2017). For instance, new environmental, planning and building laws and regulations may prohibit new turbines that have significantly higher hub heights, making repowering challenging. Or, at small sites, developers may face land availability issues because some new turbines require different turbine configurations.

How have macroeconomic factors affected renewable capacity financing costs since 2015?

Financing costs for renewables reflect a complex mix of country, company and project factors that influence investment risks, as well as the opportunity cost of investing elsewhere. In the past three years, there have been shifts – both up and down – in the macroeconomic factors shaping the cost of capital in some markets (Figure 5.8). Lower government interest rates have generally reduced the cost of long-term debt financing since 2016 in markets such as Brazil, Indonesia and Australia, while tightening monetary policies have raised rates in Mexico and Turkey. In Brazil, the government is trying to reduce the financing burden of the Brazilian Development Bank (BNDES), an important source of low-cost financing for the sector, by encouraging power companies to issue tax-exempt infrastructure bonds. In some cases, debt risk premiums – which reflect risk perceptions for lending to companies investing in renewables compared with government bonds – have also fallen. In India and Mexico, this reduction stems from the implementation of robust competitive procurement programmes for long-term contracts that have improved the bankability of projects and raised developer and financier confidence. In the United States, the perceived level of risk has decreased owing to greater clarity over the long-term trajectory of renewable tax credits (the renewal of which were uncertain in 2015) and greater availability of PPAs from corporate buyers.

Figure 5.8. Indicative change in weighted average cost of capital for renewable power investments, based on country-level economic indicators, 2015 18



Notes: WACC = weighted average cost of capital. Calculations are based on country and company data and may not represent actual changes in financing costs for given projects. Change in nominal WACC is calculated based on a uniform debt-to-equity weighting (70:30) for a notional project. Government rates are based on the 10-year bond rate.

Source: IEA analysis based on data from Bloomberg (2019), *Bloomberg Terminal*; Damodaran Online (2019), *Data*.

In contrast to debt, returns required by equity investors have generally risen, though in the United States, where markets performed more strongly in the middle of the decade, the premium has fallen. In some cases, the profiles of companies investing in renewable power are showing higher equity risks. This has happened in Germany, where market and integration risks for new renewable projects may need to be increasingly managed as policy shifts away from FITs, as well as in Japan, where incentives are not as strong as before due to the introduction of competitive auctions.

In summary, although these macroeconomic changes broadly indicate financing cost movements, they may not signal changes for individual projects, which are based on a number of specific risk and funding factors for which data access remains limited (for example, in some markets, such as China, public funding has kept financing costs relatively low and stable). Moreover, it is important to assess financing costs as part of overall profitability, a factor in investment decision-making. For instance, while the cost of capital for solar PV and wind ownership for the top power companies has fallen over the past decade, so have returns on invested capital (IEA, 2019a).

Does security of supply drive key biofuel markets in Asia?

Improving security of supply is a fundamental reason for the introduction of biofuel policy support in China, India and Indonesia, which in turn has raised production prospects. Combined, these countries account for 40% (15 billion litres [L]) of biofuel production growth in the main case forecast (2019-24).

Crude oil import dependency is set to increase in all three countries over the forecast period (Table 5.2), meaning that measures to reinforce security of supply are of paramount importance. China already overtook the United States as the largest crude oil importer in 2017, India's oil demand is set to rise 25% by 2024, and Indonesia's oil production is expected to fall significantly while demand rises.

Table 5.2. Security of supply overview

Country	Net crude importer (2018)	Import dependency (2018)	Oil demand growth (2019-24)	Oil production (2019-24)	Import dependency (2024)
China	Yes	69%	15%	-7%	76%
India	Yes	80%	26%	5%	83%
Indonesia	Yes	52%	18%	-25%	68%

Notes: Import dependency is calculated as the ratio of net oil balance to total demand. Net oil balance is the production of oil and oil-based products, minus demand, plus the net result of crude oil and product trading.

Blending biofuels with gasoline and diesel slows road transport oil demand growth

Higher vehicle ownership (linked with economic growth) contributes to rising oil import dependency in all three countries. Fuel demand from gasoline vehicles expands by one-fifth (32 billion L) in China and by over 30% (12 billion L) in India during 2019-24. In Indonesia, fuel demand for diesel vehicles increases 10% (by around 2 billion L) by 2024.

Replacing a portion of gasoline and diesel demand with biofuels is a means of increasing a country's domestic fuel supply. China produces ethanol from corn and cassava, India uses feedstocks such as molasses from its sugar industry (the world's second largest) to make ethanol, and Indonesia manufactures biodiesel from palm oil, of which it is the world's largest producer. However, the production of biodiesel in China and India, and ethanol in Indonesia, is lower because of lower domestic feedstock resources.

Security of supply can be strengthened through the application of mandate polices that prescribe replacing a share of gasoline or diesel consumption with biofuels. All three countries have established (and recently strengthened) such policies:[41]

- China: 10% of gasoline demand to be met by ethanol nationwide.
- India: 5% ethanol mandate nationwide, but 10% in major ethanol-producing states; 20% target for 2030.
- Indonesia: 20% biodiesel blending, with vehicle testing under way for 30% in road and rail transport.

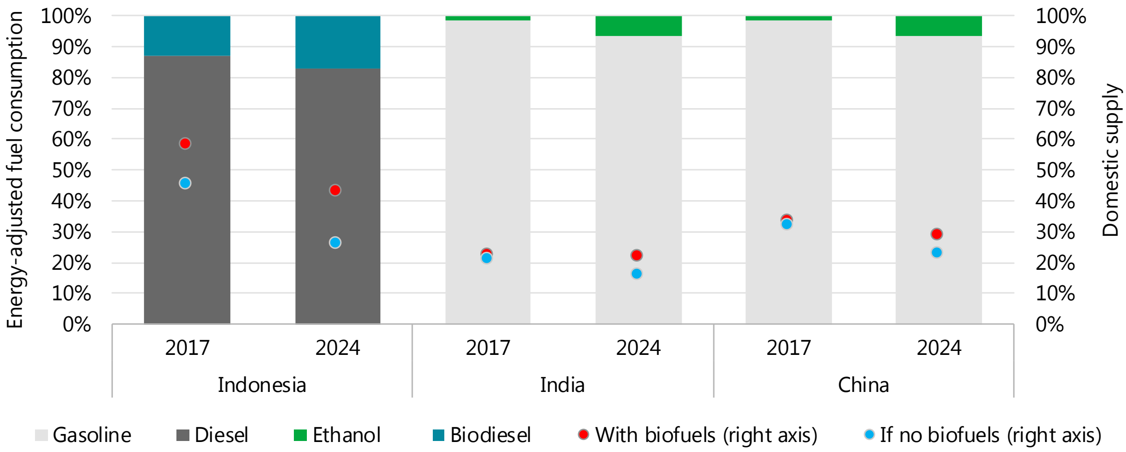
Full compliance with these policies would cause domestic supplies to meet a higher share of fuel demand from road transport in 2024 (Figure 5.9).

Nevertheless, security of supply is not the sole motivation for biofuel policy support. In China, India and Indonesia, supporting demand for nationally important agricultural commodities has also been a key factor in the introduction of mandate policies.

In energy terms, biodiesel consumption in Indonesia already resulted in a notably higher share of domestically produced fuel supplies in 2017. By 2024, its contribution could expand to offset 17% of diesel demand.[42] If vehicle testing results indicate that it is possible to use B30 fuel (30% biodiesel blending), it would offset 26% of fossil diesel demand.

In 2017, ethanol use had only a minor effect on domestic fuel supplies in China and India. However, if 10% nationwide ethanol blending is achieved, its contribution will be much more visible in 2024, replacing 6% of gasoline demand. Nevertheless, all three countries would still remain reliant on imported oil to meet transport fuel demand.

Figure 5.9. Fuel consumption and impact of biofuel policies on domestic supplies



Notes: Biofuel consumption in 2024 based on 20% biodiesel blending in Indonesia and nationwide 10% ethanol blending in China and India. Shares of biofuel energy consumption based on adjustments to diesel- and gasoline-equivalent values.

Source: IEA (2019b), *World Energy Statistics and Balances 2018* (database), www.iea.org/statistics.

[41] Percentages by volume.

[42] In energy terms, the contribution of biofuels is lower than the volume-based targets due to the lower calorific values of ethanol and biodiesel compared with gasoline and fossil diesel.

Replacing imported oil with domestically produced biofuels also improves national trade balances. Blending 10% ethanol with gasoline in 2024 would improve China's trade balance by USD 4.9 billion and India's by USD 1.2 billion, while meeting 20% of road transport diesel demand with biodiesel would improve Indonesia's by USD 1.3 billion.[43] Furthermore, if Indonesia were to use 30% biodiesel blends across all sectors of the economy, its trade deficit would fall by almost USD 4 billion. However, biofuel subsidisation and fiscal support costs must also be considered alongside these savings.

Given the scale of transport fuel consumption in these countries and ongoing demand growth, offsetting a significant share of gasoline and diesel with conventional biofuels alone would require thorough consideration of sustainability implications, as it could entail considerable land-use change and lead to debate about using edible feedstocks for fuel production. For this reason, China has expressed interest in producing cellulosic ethanol to complement crop-based ethanol production, and India is already developing several cellulosic ethanol plants.

Using biofuels in road transport is not the only way to reduce oil import dependency

Although using biofuels is a key means to slow oil demand growth in the transport sector, raising energy efficiency and harnessing electric mobility can also effectively reduce oil import dependency. Targets to increase vehicle efficiency have therefore been established in India (1.6% per year over 2012-22) and China (5% per year over 2013-20), and both countries are also expanding electric mobility. China has the largest market for electric cars and 2/3-wheelers globally, and although India has a far smaller electric vehicle (EV) fleet, it offers policy support to expand the EV market share. Indonesia, however, has less stringent efficiency requirements and EV deployment targets.

As road transport is only one cause of rising oil demand growth in these countries, the energy security improvements offered by using biofuels in this sector are less evident in the context of total oil demand, which includes consumption of products such as petrochemicals, jet kerosene and fuel oil. According to the main case forecast, ethanol use in road transport in China and India would decrease overall import dependency by less than 1% in 2024,[44] and even if India achieved 20% ethanol blending with gasoline, it would not come close to meeting the target of reducing crude oil imports 10% by 2022. Indonesia, however, has policies to use biodiesel more widely across its economy (e.g. in rail, industry and electricity generation), so the main case scenario forecasts a close to 5% reduction in import dependency. Developments in the production of aviation biofuels and biomass-based chemicals can make it possible for biomass resources to strengthen energy security over the long term in these and other countries.

What end uses will stimulate biogas production growth?

As a flexible fuel, biogas has the potential to be more widely used to provide low-carbon heat and electricity, and, if upgraded to biomethane, to offset a portion of natural gas demand or to be used in the transport sector. A variety of organic feedstocks with high moisture content (e.g. animal manure, municipal solid waste, crop residues and wastewater) can be used to

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[43] All calculations based on a crude oil price of USD 60 per barrel.

[44] The *Renewables 2019* main case forecast does not assume 10% nationwide blending of ethanol in China and India in 2024, which also results in a smaller reduction in import dependency than that shown in Figure 5.9.

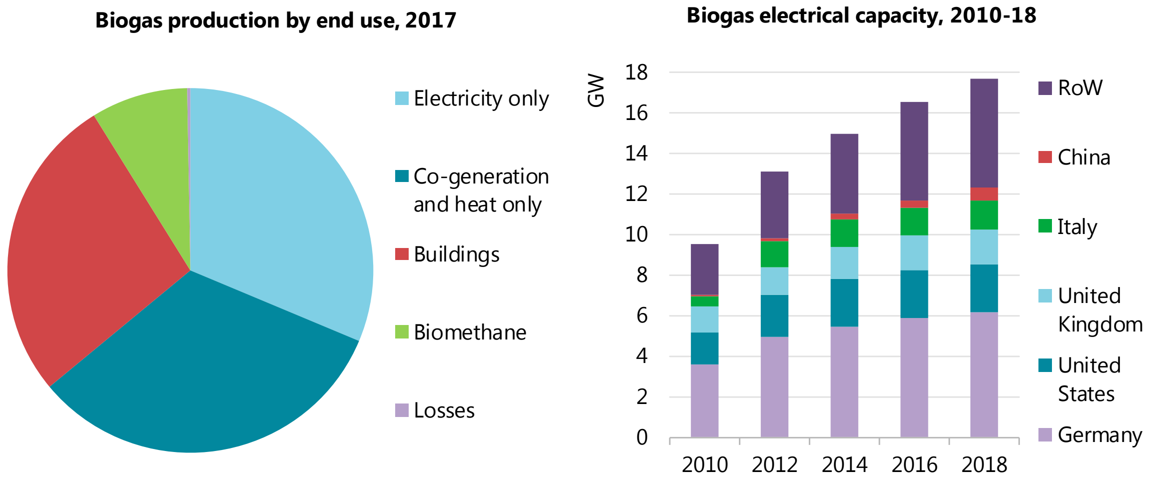
produce biogas through anaerobic digestion. The use of suitable resources is significantly underexploited, however, with production at just 6% of estimated current feedstock potential.[45]

Europe and North America were responsible for around two-thirds of biogas production in 2017, and there is still sufficient feedstock availability to further enlarge these established biogas and biomethane industries. However, most potential to scale up biogas production lies in other regions, such as the Asia-Pacific region and Latin America, where abundant feedstocks have hardly been exploited.

Two-thirds of current biogas production is used for electricity and heat generation, with an approximately equal split between electricity-only and co-generation[46] output (Figure 5.10). Global biogas-based electrical capacity reached almost 18 GW in 2018, led by Germany, the United States and the United Kingdom. Global capacity has been expanding at 5% per year in the last five years, with slower growth in the United States and some European countries contrasting with more rapid deployment in emerging markets such as China and Turkey.

Relatively higher generation costs compared with other renewable technologies mean that market prospects for biogas electricity generation are set to become more challenging. However, upgrading biogas to biomethane opens up new applications in transport and injection into natural gas networks, which could become the principal uses of biogas.

Figure 5.10. Biogas market overview



Note: RoW = rest of world.

Sources: IEA (2019b), *World Energy Statistics and Balances* (database), www.iea.org/statistics/; IEA (2019c), *Renewables Information* (database), www.iea.org/statistics.

[45] The *World Energy Outlook 2019*(*WEO*) (IEA, forthcoming) provides an in-depth assessment of biogas feedstock potential.

[46] *Co-generation* refers to the combined production of heat and power.

Market context more promising for co-generation than for electricity-only biogas plants

The transition from FITs to competitive renewable electricity auction frameworks (e.g. for PPAs) in many markets may reduce market prospects for electricity-only biogas plants. A less supportive policy landscape for biogas electricity in key European markets is one of the reasons for slower biogas production growth since 2015.

Auction design will be crucial in shaping biogas deployment opportunities in the electricity sector. The levelised cost of electricity for biogas varies according to the feedstock(s) used and the sophistication of the biogas plant.[47] Most projects fall within the range of USD 50-190/MWh, and generation costs at the middle to higher end are likely to be above those of wind and utility solar PV. Technology-specific auctions may therefore be required to realise the potential of biogas to deliver wider benefits such as flexible generation, improved waste management and rural development.

Where local heat offtake is available, the economic case for biogas co-generation is usually stronger than for an electricity-only plant. This applies especially to industry subsectors that produce wet wastes with high organic content that are suitable feedstocks for anaerobic digestion (e.g. the food and drink and chemicals subsectors). In such industries, biogas production can have the co-benefit of providing treatment of wastewater that has high levels of organic pollutants while also supplying on-site heat and electricity. Despite these advantages, biogas potential in industry remains highly underexploited.

Biomethane use in natural gas grids and transport is scaling up

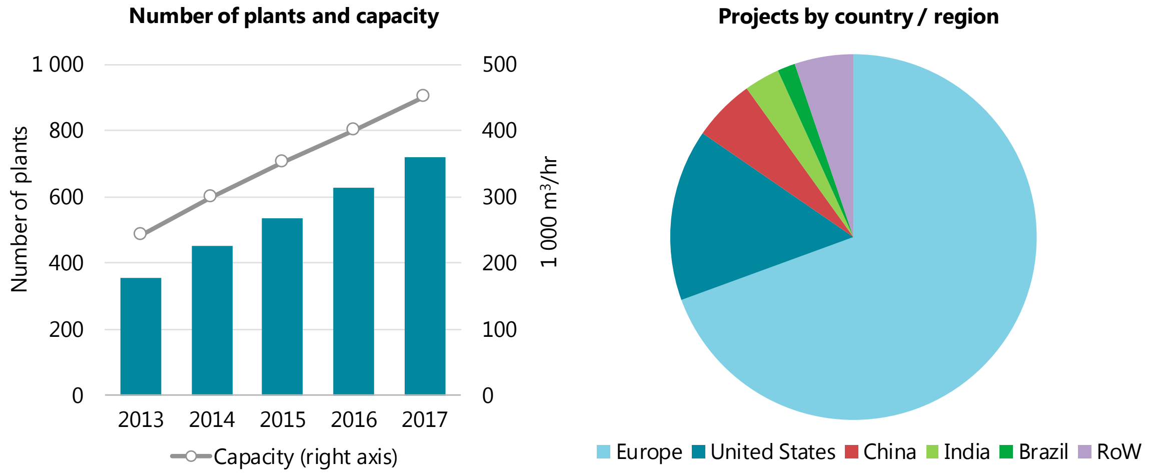
Additional upgrading can raise the quality of biogas composition to that of natural gas, resulting in biomethane (or renewable natural gas in North America) that is suitable for injection into the natural gas network or for use in natural gas vehicles. Although biomethane market development is at an early stage, there are indications that the growth potential for these applications is considerable.

In 2017, biomethane accounted for 8.5% of biogas production (by energy), and the number of biomethane plants globally passed the 700 mark (CEDIGAZ, 2019). Judging by the project development slate, there will likely be over 1 000 plants operational by 2020. Deployment is also spreading from pioneering European and North American markets to a wider array of countries (e.g. China, India and Brazil), as the number of plants in these countries tripled from 2015 to 2017 (Figure 5.11, right). Higher levels of waste collection and source-segregation of organic waste streams could boost biogas production significantly in these and other emerging economies.

Around 60% of plants currently online and in development will inject biomethane into the gas distribution network. Once injected, renewable biomethane is indistinguishable from natural gas and can meet demand from industry, buildings, power generation and transport. To enable the application of policies to support biomethane consumption, registries provide the guarantees of origin needed to track and balance the quantities of biomethane injected and consumed. Such registries already exist in several European countries, including Germany, France and the United Kingdom. The harmonised development of such registries can facilitate the virtual trading of biomethane across borders.

[47] Systems with higher investment costs can offer increased automation, a longer operational life and reduced methane slip.

Figure 5.11. Biomethane market overview



Note: Plants by country includes plants online and in development.

Source: CEDIGAZ (2019), Global biomethane market: Green gas goes global.

In Denmark, the Netherlands and the United Kingdom, policy support means that most biomethane production is destined for injection into gas networks:

- Denmark: 20-year feed-in premium for biomethane injection (open to new applicants until end 2019), with a tendering policy for biomethane and other green gases in development.
- The Netherlands: fixed-tariff biomethane injection over 12 years under Sustainable Energy Production (SDE+) scheme.
- The United Kingdom: Renewable Heat Incentive (RHI) scheme tariff for grid injection with 20-year support.

France is also a key growth market owing to its guaranteed 15-year FIT, targets for biomethane injection of 8 terawatt hours (TWh) by 2023 and 10% of gas consumption to be renewable by 2030, and regulations that prioritise grid injection over co-generation when a gas distribution network is available.

A further 20% of plants are dedicated to providing biomethane for road transport. Several factors drive demand for biomethane as a transport fuel: it delivers significantly lower CO_2 and air pollutant emissions than fossil gasoline and diesel, and domestically produced biomethane diversifies the fuel supply in oil-importing countries. For example, consumption in China and India is mainly for road transport.

The United States leads biomethane use in transport, with around 80% of production destined for vehicles (CEDIGAZ, 2019). Consumption has doubled in the last three years, largely owing to financial incentives from the federal Renewable Fuel Standard and California's Low-Carbon Fuel Standard. Italy heads European deployment because of its well-established natural gas vehicle fleet, its expanding fuelling network, and policy support for production, liquefaction and refuelling infrastructure.

In countries without extensive gas distribution networks, biomethane is used predominantly in transport. Sweden, which has a limited gas network, is a good example, as around 90% of methane used in transport in 2018 was renewable (Bioenergy International, 2018).

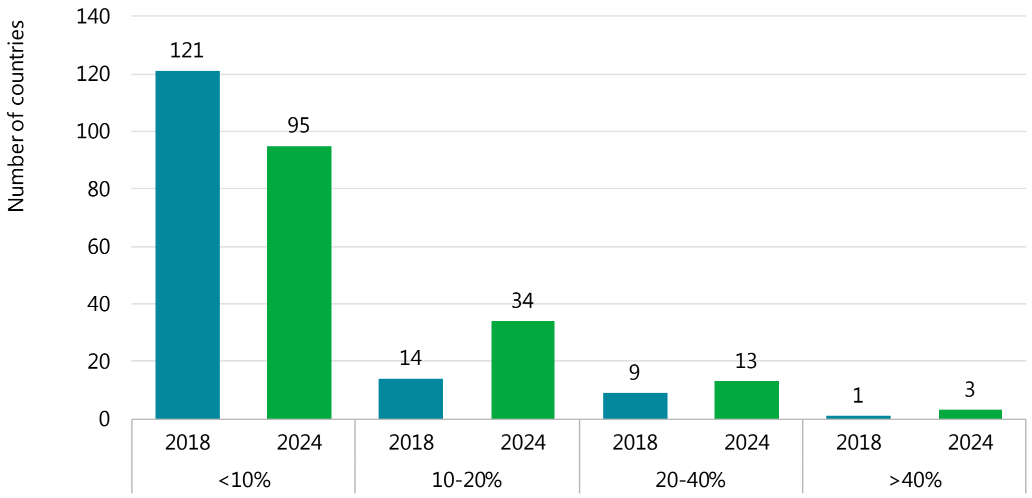
Maximising the potential for biomethane use in transport necessitates natural gas fuelling infrastructure along key transport corridors. This is evident in the United States and Italy and is emerging in the United Kingdom, and in India there is also growing interest in rolling out supply infrastructure along intercity transport corridors. Furthermore, there are already over 27 million natural gas vehicles in operation globally (NGV Global, 2019). Argentina, Brazil, China and Pakistan possess some of the largest fleets, so if biomethane production were to expand in these countries, the existing fuelling infrastructure would facilitate its integration into the fuel supply.

Given that its production costs are higher than for natural gas, growth in demand for biomethane injection into natural gas networks and for use as a transport fuel will depend on policy support. Best-practice policy development dictates an integrated approach involving various areas of government, as biogas affects multiple policy areas (e.g. agriculture, energy, transport and waste).

Should grid integration be a concern for policy makers in countries with low wind and solar deployment?

Electricity generation from solar PV and wind, also known as variable renewable electricity (VRE), has expanded rapidly, having reached double-digit shares in some countries. However, the share of VRE in the vast majority of countries is relatively low (under 10%) and is expected to remain so until 2024 (Figure 5.12). Because many countries are just beginning to launch VRE deployment, this section focuses on the early stages. It aims to clarify the central challenges to launching solar and wind deployment and to share best practices to address and manage these obstacles successfully. At the beginning of the deployment process, wind and solar integration challenges are often not as serious as anticipated.

Figure 5.12. Distribution of variable renewable shares across countries, 2018 and 2024



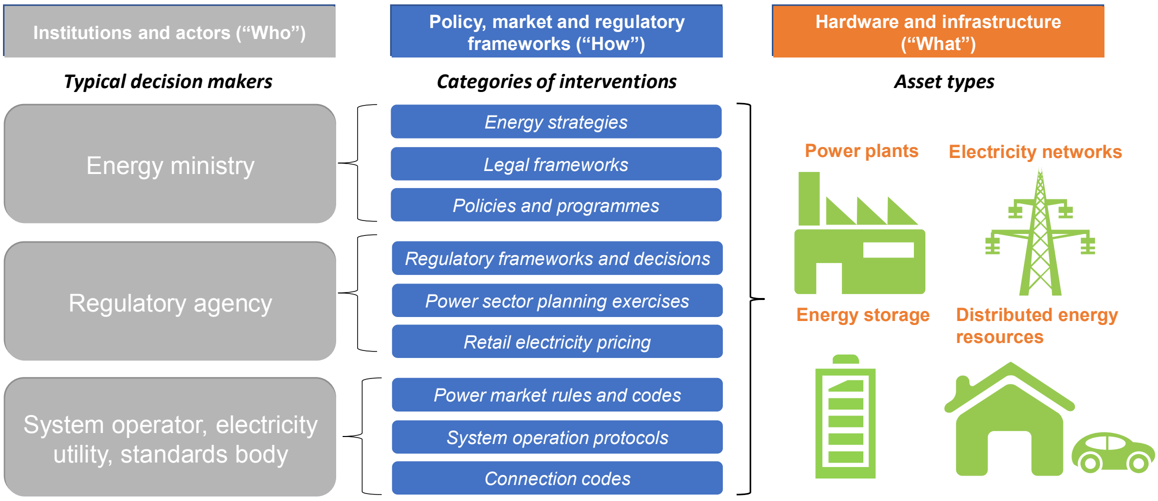
Electricity generation from VRE differs in several ways from dispatchable conventional power generation (e.g. from thermal generators and hydropower plants). Most importantly, VRE output fluctuates over time because of the variability of wind and sunlight availability. For this reason, power system flexibility – the ability to effectively respond to fluctuations in supply or demand – becomes increasingly important to integrate rising VRE shares. In addition to increasing VRE shares, however, numerous other structural and institutional factors also influence system flexibility. Therefore, using only the VRE share as an indicator of additional system requirements should be just the first step in identifying and developing specific integration strategies. A complementary approach uses phases to categorise the different stages of impact that VRE deployment has on the power system. While experience has shown that the sequence of these impacts is relatively consistent across power systems, the VRE share at which they become a challenge depends on each power system's flexibility.

The IEA's phase framework categorises VRE integration into six stages. Phase 1 is the earliest stage, at which VRE deployment has no immediate impact on power system operations, while in Phase 2 the system is able to cope with minor operational changes through existing system resources. Phases 3 through 6 imply that: 1) VRE determines the operating pattern of the whole power system; 2) additional investments in flexibility are needed; 3) there are structural surpluses of VRE generation that lead to curtailment; and 4) the seasonal and inter-year structural imbalances in energy supply require sectoral coupling (IEA, 2017a).

In 2018, almost all assessed countries with a VRE share of less than 10% fell into Phase 1 or 2. In 2024, the VRE level is expected to still be below 10% in close to 100 countries. However, assessing VRE shares at an aggregated national level to determine integration into a country's power system may be misleading, as local VRE shares can vary considerably. For example, VRE shares in some Chinese provinces and Indian and US states are higher than in the national system overall. Even though only handful of countries will be in Phase 4 by 2024, global policy focus has been mostly on actions and approaches that concern only the higher phases.

For countries at early VRE deployment stages (Phases 1 and 2), there may be no immediate integration concerns if the power system's ability to cope with demand uncertainty is greater than the flexibility needed to accommodate small shares of VRE. However, in power systems with relatively weak and small grids, or with ambitious VRE deployment targets, it is still very beneficial to proactively initiate reforms of different parts of the institutional framework, even at early deployment stages. Figure 5.13 depicts the different areas for policy intervention and the variety of stakeholders involved in enabling power system transformation on the institutional side, a process that usually takes considerable time (IEA, 2019d).

Figure 5.13. Layers of power system flexibility



Source: IEA (2019d), *Status of Power System Transformation 2019*.

At the initial stages of VRE deployment (Phases 1 and 2), several options can facilitate the integration of renewables (Table 5.3). Actions such as developing technical codes and adjusting regulations can help prevent integration challenges arising from greater VRE deployment. For example, governments can use connection codes or support mechanisms that require new VRE installations to use remote monitoring and control mechanisms.

Table 5.3. Priority actions for initial-phase system integration of VRE

Possible challenges	Actions
Can the grid accommodate VRE at the identified site?	Solve local grid issues and/or introduce flexibility provisions into the interconnection agreement.
Is the grid connection code appropriate?	Develop or upgrade codes with stakeholders.
Is VRE reflected in system operations?	Ensure transparency and controllability of power plants; install VRE forecast system and assign balancing responsibilities appropriately.
Is the grid adequate for continuing VRE deployment?	Improve operational strategies and consider grid expansion.
Is VRE being deployed in a system-friendly way?	Manage VRE deployment locations and technology mixes.

Similarly, connection codes can include provisions for active network management or VRE zoning to optimise the use of existing electricity networks. In some cases, market reforms that enable VRE participation in ancillary services may be useful to supplement VRE income and facilitate its integration into the power system.

Although actions in Phases 1 and 2 appear to be business-as-usual measures, they are in fact taking full advantage of a window of opportunity to accelerate system transformation. Targeting options with longer lead times (such as planning exercises) or legal frameworks to prepare institutions for wider system transformation can be done early on to prepare for medium- to long-term scaled-up deployment. Such measures may include evaluating market design and assessing future system needs to help policy makers identify areas with market or regulatory reform opportunities, as well as to raise confidence in projects with long lead times.

System integration can already be embedded in VRE support policies during the initial phases of VRE deployment. Historically, VRE deployment policies have focused on removing risks to stimulate rapid development, but as VRE becomes increasingly cost-competitive, policy makers could consider more advanced deployment policies that encourage system integration to prepare the electricity system for subsequent phases. These can include:

- Increasing market exposure by shifting to direct marketing schemes that allow VRE operators to sell electricity to the wholesale market rather than having system operators as off-takers. This would avoid some of the challenges posed by fixed FITs with assured offtake from incumbent utilities or system operators, wherein VRE generators operate independently from real-time system conditions.
- Increasing market revenue exposure by introducing floating premiums based on technology-specific average market values. The use of average market value can further support system integration through implicit locational incentives, spurring the strategic construction of VRE installations at locations where output is more likely to provide value to the system.
- Offering VRE support payments according to equivalent full-load hours rather than on a per-year basis. This provides an incentive for VRE operators to curtail output at times of negative wholesale prices and may be enhanced by enabling VRE participation in ancillary services.
- Supporting grid integration through site pre-selection and proactive network planning to reduce time lags between project construction and grid connection.
- Requiring the installation of remote monitoring and control equipment as a precondition to participate in auctions and support schemes, which can limit variability impacts on the grid. This is particularly important for programmes targeting rapid VRE capacity expansion.

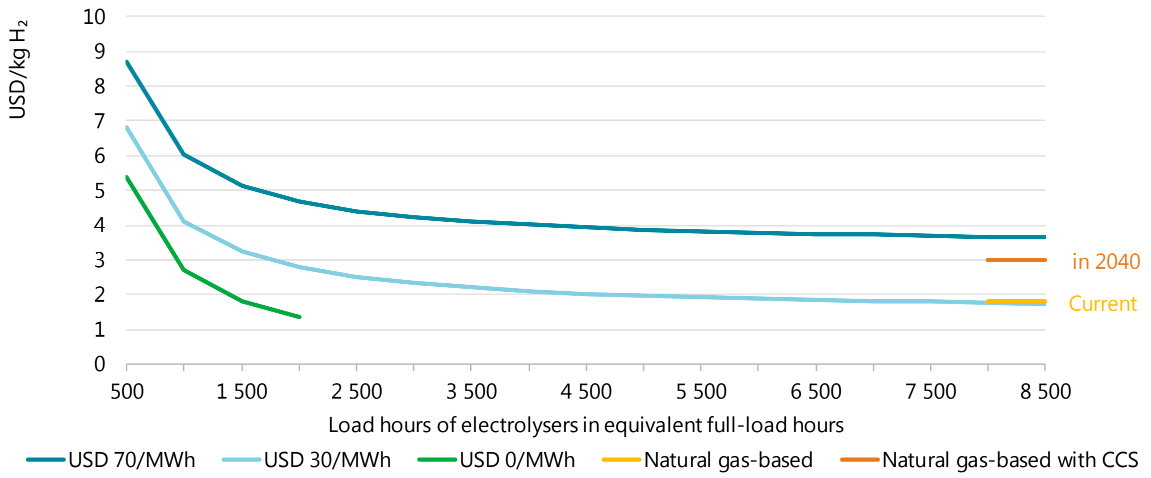
What will be the role of hydrogen in renewable energy deployment by 2024?

Hydrogen (H_2) can support the deployment of renewables in two distinct ways. It can provide low-carbon fuel for the power sector through fuel cells or thermal plants in places where renewable resources are limited or too expensive, or when sunshine/wind levels are low. It can also be used to help decarbonise hard-to-abate sectors such as steel, chemicals, trucking, shipping and aviation. In both cases, producing low-carbon hydrogen through the electrolysis of water could provide significant new market opportunities for renewable electricity technologies while helping to harness vast renewable energy resources stranded in areas that are far from demand centres (e.g. desert or semi-desert areas of Africa, Asia and South America, or even areas far into the ocean).

Although low-carbon hydrogen could be made from fossil fuels through CO_2 capture and storage (CCS) or by splitting methane into hydrogen and solid carbon, sharply declining variable renewables costs would make water electrolysis an affordable way of providing hydrogen in a growing number of cases (IEA, 2019e) – even if electrolysers do not run constantly.

One option is to exploit very inexpensive electricity from "excess" variable renewable generation that would otherwise be curtailed (Figure 5.14), green line [USD 0/MWh]), but these locations are very limited and it might not be possible to sustain zero-priced electricity over the asset's lifetime (IEA, 2017b). More realistically, hydrogen could be produced around the clock from less-costly power generation sources. Another option is to use solar and/or wind in areas with excellent resources, where generation costs can be as low as USD 30/MWh (light blue line), but a lack of local demand means the resources have not yet been harnessed.

Figure 5.14. Cost of hydrogen produced from electrolysis vs. natural gas, at different electricity prices and load factors



Note: kgH_2 = kilogramme of hydrogen.

As a low-carbon fuel for use in the power sector, pure hydrogen can be stored in steel tanks or underground caverns, or a hydrogen-rich fuel such as ammonia (NH_3) could be employed, as it is easier to store and ship. The fuel could be produced locally at times of low electricity prices or imported from elsewhere by ship or pipeline. In the Netherlands, the Nuon project will adapt three combined-cycle gas turbines (CCGT) to burn hydrogen, and Japan plans to procure ammonia from Australia for co-combustion in coal plants and to substitute for natural gas in CCGTs.

Islanded power systems based on solar PV or wind power may use a combination of batteries, hydrogen storage and fuel cells to displace diesel-fuelled power generators, as planned for village electrification in French Guyana and in the mining industry in Canada. In Kenya and India, there are examples of off-grid deployment of fuel cells running on either ammonia or methanol to power isolated telecom relays; however, the ammonia and methanol used are currently produced from fossil fuels.

Globally, the industry sector already uses 70 million tonnes (Mt) of hydrogen, mostly produced from fossil fuels and thus responsible for 2% of global CO_2 emissions. It serves as a feedstock for producing ammonia (the basis for nitrogen fertilisers and explosives), as well as methanol, central in the production of numerous chemicals. In refining, hydrogen cleans and upgrades petroleum products. Low-carbon hydrogen could replace coal in pig iron production and, together with electric mills, be crucial in abating steel industry emissions of around 2 500 $MtCO_2$ annually.

Hydrogen could also be used to help decarbonise the transport sector, particularly in transport modes for which direct electrification is difficult or seems impossible, notably long-haul trucking, shipping and aviation. Ammonia could be the fuel of choice for maritime shipping: a very large manufacturer claims it will be able to deliver ship engines running on 95% ammonia in just a few years – including by the transformation of about one-third of existing vessels. Synthetic hydrocarbons would best fit the needs of aviation, as they could significantly reduce emissions if they are made from renewable hydrogen with carbon from seemingly unavoidable CO_2 emissions (such as the process emissions of cement-making) – or better yet, from sustainable biomass or through direct air capture technology.

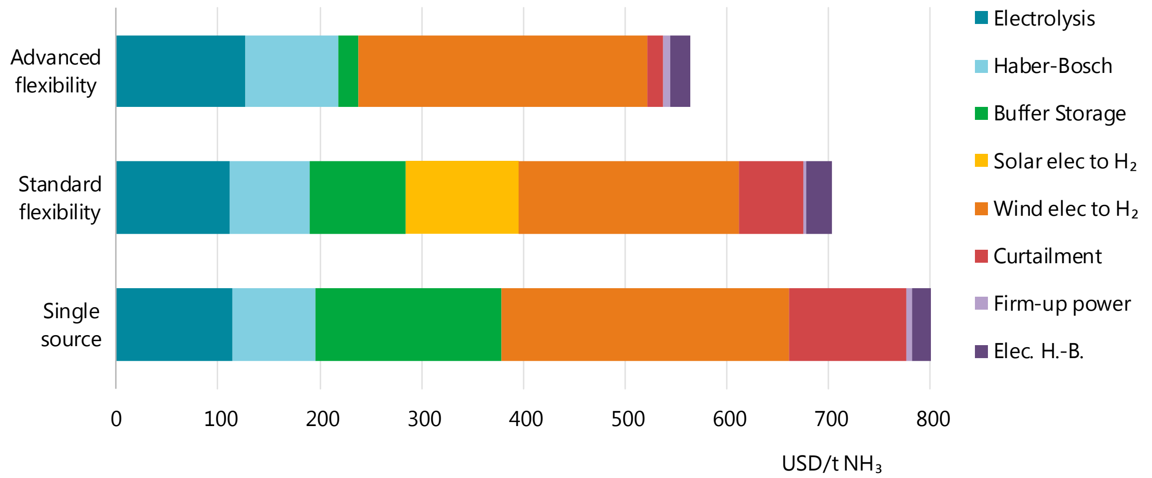
Renewables-based hydrogen is already being produced, although at a very small scale; there are now about 200 power-to-gas demonstration projects, mostly in Europe (notably Germany) (Chehade et al., forthcoming). Refineries and steelmaking plants have been installing electrolysers of 5 MW to 10 MW, and the Swedish iron and steel industries joined forces to build, with government's support, a pilot plant making green steel with hydrogen from a mix of hydro and wind power.

Some larger projects (in the 100-MW range) are under consideration, though final financing decisions have not been made. Some Australian and Chilean projects would deliver green ammonia, and another in France would inject hydrogen gas or synthetic methane into natural gas grids. The largest project – run on hydropower and located in Paraguay – could produce hydrogen for hydrotreating vegetable oils and manufacturing aviation biofuel.

Electrolysers can adapt relatively easily to the variable electricity supplied by solar and wind, so would ease the integration of large shares of variable renewables into an energy system. This may not be the case, however, for all subsequent transformations or uses of hydrogen, and hydrogen storage to "buffer" these variations may be expensive unless underground storage options are available.

As an example, the IEA studied ammonia production from variable renewables in Argentinian Patagonia (Figure 5.15). With normal flexibility of the chemical loop that associates hydrogen with nitrogen, if the plant runs on wind power only, storing six days' worth of maximum-level hydrogen production in steel tanks is optimal but accounts for almost one-fourth of the total ammonia production costs (USD 800 per tonne [/t]) while not preventing significant wind power curtailment (Figure 5.15, "single-source" bar). Storage and curtailment costs fall considerably if the chemical plant runs on an optimal mix of solar and wind, overcompensating for the higher cost of solar in very windy Patagonia ("hybridisation" bar). Finally, the need for storage shrinks to about half a day's worth of production in the case of "advanced flexibility" ammonia production, as it accommodates fluctuations in hydrogen delivery. In this case, less-expensive wind resources supply all the electricity, making the cost of renewables-based ammonia production more competitive. Fossil fuel-based ammonia production costs vary from USD 300/t to USD 600/t – but would be higher if CCS were mandatory or a carbon tax were imposed.

Figure 5.15. Production of ammonia from solar and wind in Argentinian Patagonia



Source: Adapted from Armijo and Philibert (forthcoming), Flexible production of green hydrogen and ammonia from variable solar and wind energy: Case study of Chile and Argentina.

Hydrogen and its compounds could therefore have important applications for decarbonising many sectors of the economy while offering novel opportunities to the renewable energy industry. Deployment is challenging, however, because the most expandable energy resource options are variable solar and wind power. In addition, the overall costs of hydrogen-rich materials and fuels are still higher than for fossil fuels, and incentives to reduce CO_2 emissions are still absent or insufficient. As pilot and first-of-a-kind commercial renewable hydrogen projects increase in number and size, the next six years will be decisive in confronting these barriers.

Has energy efficiency helped EU countries reach renewable energy targets?

Targets for the share of renewable energy in final energy consumption have been established in the European Union, with a collective target of meeting 20% of energy demand from renewable energy by 2020 and individual targets for each member state reflecting their different circumstances.

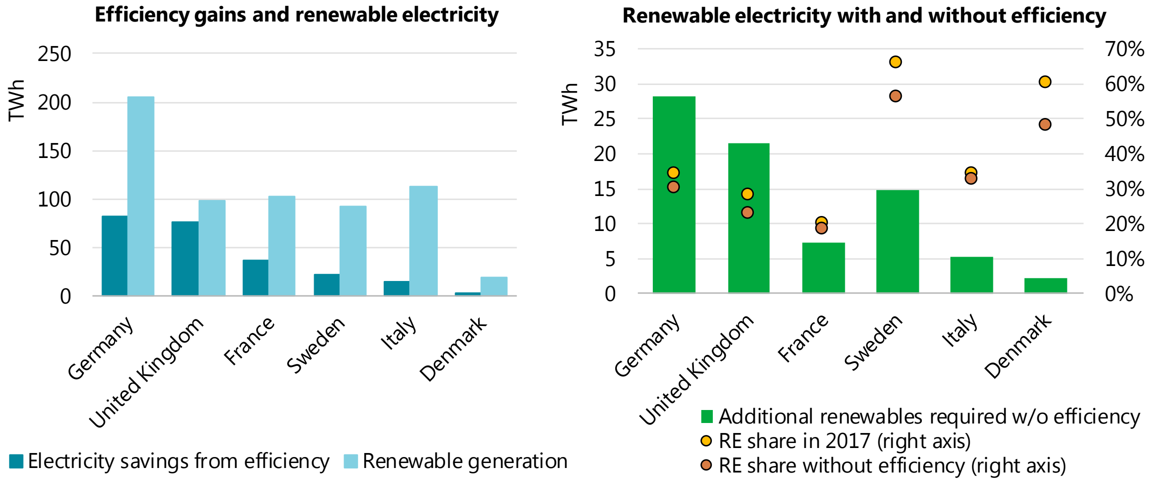
Energy efficiency improvements, which reduce or maintain energy demand despite growth in service levels, multiply the impact of each additional unit of renewable energy, making it easier to meet such targets. Expanding renewable energy penetration is underpinned by growth in renewable electricity, which is complemented by improvements in the efficiency of electricity consumption. Enhanced efficiency is most apparent in the buildings and industry sectors, where policies such as minimum energy performance standards (MEPS) for electrical equipment and appliances, more stringent building codes, utility obligations and energy audits have driven efficiency gains in the European Union.

In major EU member states, the impact of energy efficiency on the level of renewable energy in electricity generation has been significant (Figure 5.16). In the United Kingdom, energy efficiency advances since 2000 have resulted in over 76 TWh of avoided electricity use – equivalent to nearly 80% of the country's renewable electricity generation in 2017. Similarly, in Germany and France, efficiency improvements since 2000 correspond to around 40% of total renewable electricity generation in 2017.

If these efficiency gains had not been achieved and the subsequent additional electricity demand met by fossil fuel-based generation, the amount of renewable energy in EU electricity generation would have been lower. In Germany, without the efficiency gains made since 2000, renewable energy would have represented just over 30% of total electricity generation in 2017 – instead of nearly 35%. The reduction would be similar for the United Kingdom, but the largest would be in Denmark, where renewable energy penetration would have been nearly 10% lower.

To maintain the 2017 share of renewable energy in electricity generation without efficiency gains, Germany would have required nearly 29 TWh or 15% more renewable electricity, equivalent to one-quarter of Germany's residential electricity consumption. A similar percentage of additional renewable energy would have been needed in Denmark and Sweden, with the United Kingdom needing over 20% more.

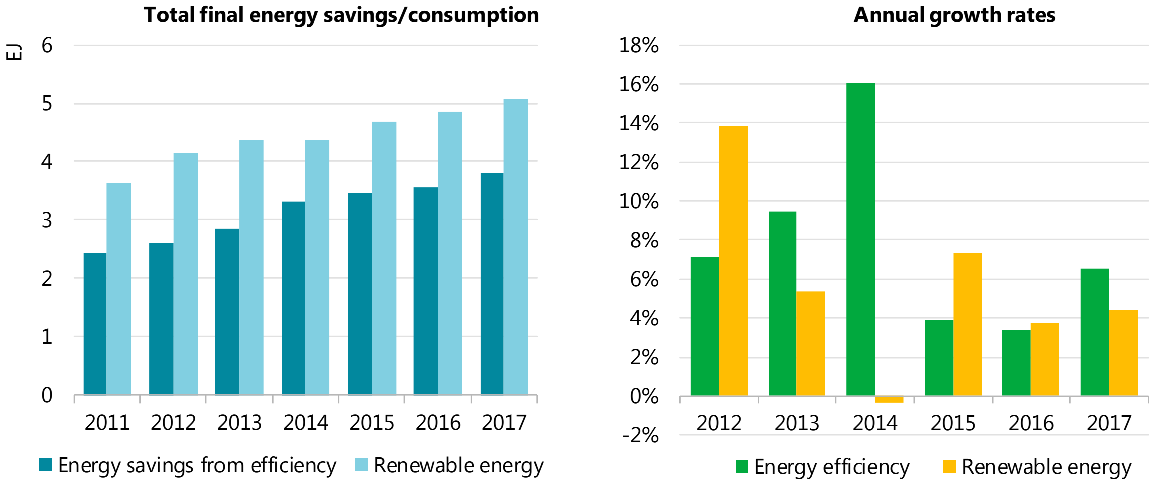
Figure 5.16. The role of efficiency gains for renewable electricity targets in selected European countries, 2017



Notes: RE = renewable energy. Sweden and Denmark data are for 2016. Electricity savings from efficiency improvements are since 2000.

The contribution of energy efficiency is more apparent when considered across total final energy consumption, when the impact of policies in transport (particularly fuel economy standards) and buildings (particularly those affecting gas space heating demand) is taken into consideration (Figure 5.17). Avoided energy use across all end uses as a result of efficiency gains since 2000 in Denmark, France, Germany, Spain and the United Kingdom was equivalent to around 75% of all renewable energy consumption in 2017 for these economies. While both efficiency gains and renewable energy use continue to increase in these economies, efficiency has improved more quickly, at an average of 8% per year since 2012 compared with 4% for renewable energy consumption.

Figure 5.17. Energy efficiency savings and renewable energy consumption across all end uses for selected European countries



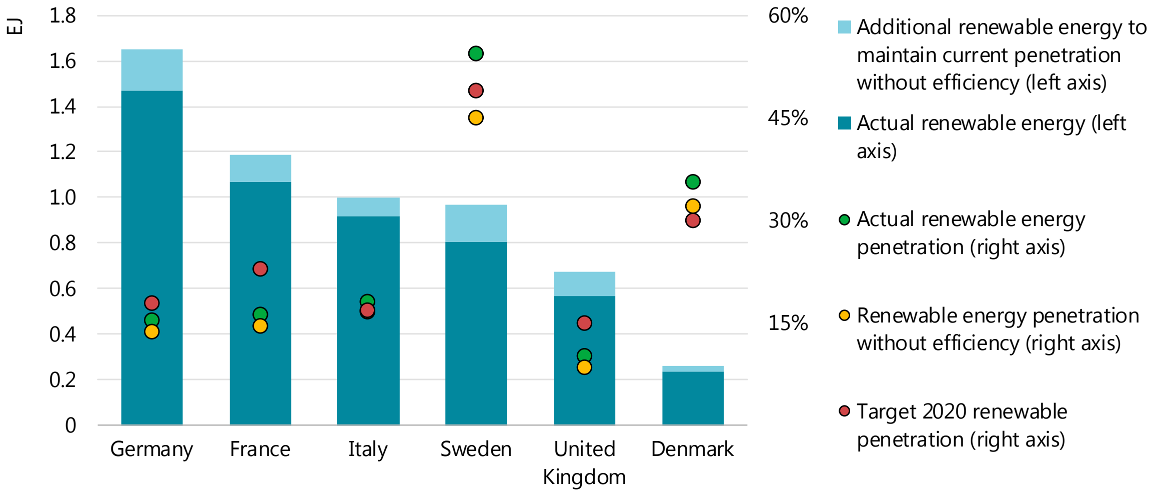
Notes: EJ = exajoule. Countries included are Germany, the United Kingdom, France, Italy, Denmark and Sweden. Energy savings from efficiency improvements are since 2000.

Efficiency gains across all sectors will continue to be vital for EU member states seeking to meet their 2020 renewable energy targets, especially as renewable energy deployment in several has not been sufficient to meet (or exceed) their goals. Of the six member states analysed, Italy, Sweden and Denmark had exceeded their 2020 targets by 2017; however, if not for efficiency gains since 2000, Italy and Sweden would not have exceeded theirs (Figure 5.18). Without efficiency improvements, Sweden's renewable energy penetration would be 10% less, meaning that nearly 170 petajoules (PJ) of additional renewable energy would have been required to maintain the current share – equivalent to one-third of Sweden's industrial energy consumption.

Germany is advancing towards its renewable energy target for 2020, such that in 2017 it was 2.5% away from meeting it. Without efficiency gains since 2000, however, the gap to the target would have been nearly 4.5%, with 190 PJ of additional renewable energy needed to maintain the current level. Impacts are similar in France and United Kingdom, as both would require over 105 PJ of additional renewable energy to maintain levels of penetration in 2017 in the absence of energy efficiency contributions.

The complementarity of renewable energy and energy efficiency can be maximised in the right policy setting. In the case of the European Union, using renewable energy penetration targets has prompted countries to raise energy efficiency in order to reduce the amount of renewable energy required to meet their targets, thereby reinforcing both outcomes. With other targets, such as those specifying absolute levels of renewable energy, higher levels of energy efficiency are not necessarily beneficial, as meeting the targets would cost the same regardless of level of end-use efficiency.

Figure 5.18. Renewable energy generation and penetration with and without efficiency gains since 2000, for selected EU member states in 2017



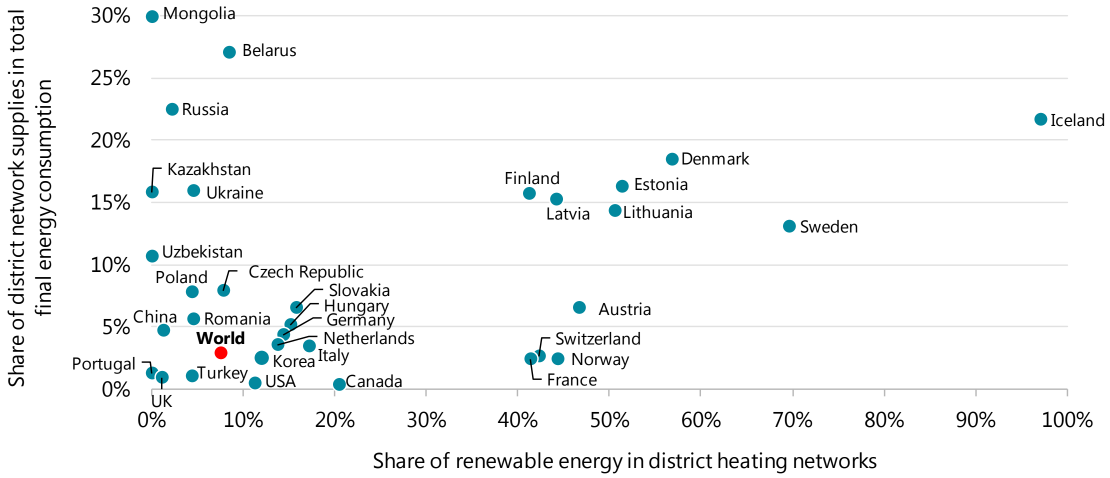
Source: IEA analysis based on Eurostat (2018), *SHARES 2017*.

How can district heating help decarbonise the heat sector by 2024?

District heating and cooling (DHC) networks distribute heat for domestic hot water, space heating or cooling in buildings, and industrial processes. In 2018, a little less than 6% of global heat consumption was supplied through DHC networks, of which Russia and China each accounted for more than one-third.

China, responsible for more than one-quarter of global heat demand, has the world's fastest-growing district heating capacity. In 2005, district networks heated around 40% of floor area in the provinces that make up the Northern Urban Heating Area. Since then, over 95% of floor area growth resulting from greater urbanisation has been covered by district heating, and the amount of heat supplied through DHC has almost doubled, amounting to 8% of the country's heat consumption in 2018. In Russia, despite a decline since 2012, DHC still provides more than one-third of the country's heat consumption. DHC networks are also well established in the European Union, where they meet more than 8% of total heat demand. Finland, Denmark, Sweden and Baltic countries have the highest penetrations of district heating in Europe (Figure 5.19).

Figure 5.19. Renewables in district heating, and district heating in total final energy consumption, 2018



Source: IEA (2019b), *World Energy Statistics and Balances* (database), www.iea.org/statistics

Fossil fuels are still by far the dominant energy source in DHC globally, due to the extensive use of natural gas in Russia and coal in China; overall, renewables accounted for only less than 8% of energy used in district heating in 2018. Yet, renewable energy consumption for DHC increased more than two-thirds during 2009-18, mainly as a result of the extensive transition from fossil fuels to bioenergy in the European Union.

Bioenergy is indeed the largest source of renewable energy in district heating worldwide by far, although Iceland has achieved close to 100% renewables owing to its excellent geothermal resources. Even though heat pumps and solar thermal systems still account for only a marginal share of district heating energy, development continues, as new high-efficiency district systems with lower operating temperatures make their integration possible. Denmark leads the way in integrating solar thermal energy in district heating, accounting for more than three-quarters of the 1.2-gigawatt thermal (GW_{th}) of installed capacity worldwide by the end of 2018[48] (IEA SHC, 2019).

Globally, energy demand met by district heating is expected to increase modestly (+4%) over the next six years, its share in total heat demand remaining flat. However, renewable energy consumption for DHC is anticipated to expand more than 40% globally, contributing a little more than 8% of renewable heat consumption growth over 2019-24 (Figure 5.20). China is responsible for more than 80% of this increase. Replacing inefficient individual coal-fired boilers with district heating systems, and using alternative fuels such as bioenergy and waste in these systems, is part of the country's strategy to fight air pollution in large cities. Outside of China, the expansion of renewables in DHC decelerates from the previous six-year period in many countries and regions. European countries are expected to be the second-largest contributors to projected renewables growth during 2019-24, mostly because more bioenergy is used in existing and new DHC systems. In Russia – where district network infrastructure is old and very inefficient – and in

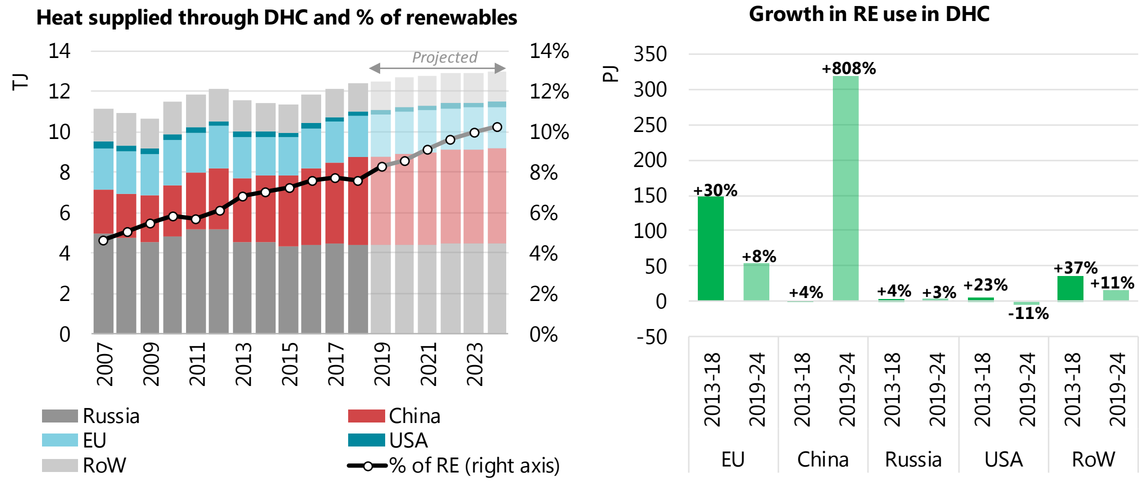
[48] Although solar thermal production for district heating in Denmark has expanded more than tenfold since 2010, it still made up less than 3% of district heating energy supplied in 2018.

the United States, renewable expansion in DHC remains limited or non-existent due to lack of policy support.

Interest in DHC in cities is often motivated by a combination of energy security, economic, environmental and governance considerations. Indeed, DHC networks are potentially one of the most effective means to harness renewable energy to meet heating and cooling demand because they offer:

- Economies of scale and high efficiency potential through aggregation of demand.
- A way to circumvent building suitability and consumer awareness barriers.
- Renewable energy storage possibilities (thanks to thermal inertia), and the opportunity to integrate thermal storage technologies and benefit from heat and power coupling.

Figure 5.20. District heat consumption and the share of renewables



Note: TJ = terajoule.

Sources: IEA (2019b), *World Energy Statistics and Balances* (database), www.iea.org/statistics/; IEA (forthcoming), *World Energy Outlook 2019*.

This potential remains largely unexploited, however, as there are opportunities in many countries to deploy new DHC infrastructure, improve the energy efficiency of ageing ones (e.g. with better-insulated pipes and higher-efficiency heat generators), and integrate higher shares of renewables into existing networks.

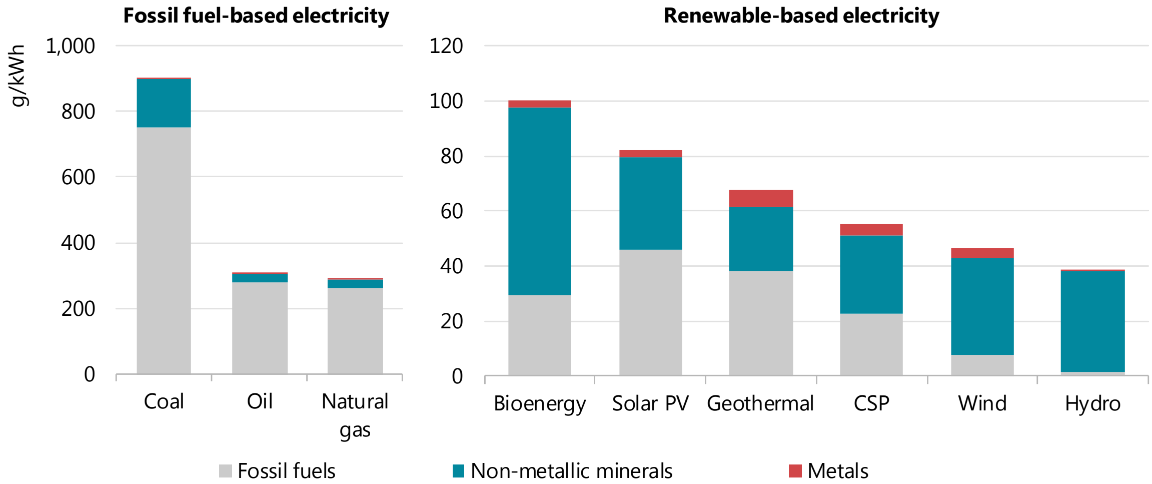
Municipal and city-level policies are needed to boost the use of renewables in district heating. Local governments can use their authority as planners and regulators not only to influence DHC deployment, but also to control network ownership and management (either directly through municipal energy companies, or through tendering procedures), as most business models for district energy involves the public sector. Common policies and strategies for establishing district networks include heat-mapping exercises, the leveraging of public assets, support for demonstration projects, financial and fiscal incentives, connection regulations for buildings, and development-based strategies that capture land value (UNEP, 2015). Given that district heating schemes generally imply situations of natural monopoly or oligopoly, pricing transparency and customer protection deserve specific attention. National-level support also strengthens local initiatives significantly.

How big is the mineral resource footprint of renewable electricity development?

Although renewable electricity technologies generate much lower CO_2 emissions than fossil fuel power plants, their large-scale deployment has raised concerns about higher mineral requirements and related environmental and social impacts (e.g., Kleijn et al., 2011; Jacobson and Delucchi, 2011; Hertwich et al., 2015; Koning et al., 2015; and Boubault and Maïzi, 2019). Mineral resource extraction for renewable technologies can be quantified using material footprint indicators (derived from process-based life-cycle inventory (LCI) databases) that account for the natural substances mobilised or transformed during an electricity-generating technology's lifecycle (Figure 5.21). This includes the mineral resources and fossil fuels extracted for the manufacturing of equipment and its transport, the construction of infrastructures, their operation[49] and decommissioning, taking into consideration regional variations in energy supply, and construction and operation processes across countries.

Most of the material footprint (on a weight basis) of renewable technologies is made up of non-metallic minerals (e.g. aggregates, gravel, calcite, clays, shale and gypsum) and raw fossil fuels extracted for infrastructure construction.

Figure 5.21. Lifecycle mineral resource footprints of various electricity generation technologies



Notes: g/kWh = grammes per kilowatt hour. While operations are responsible for most of the mineral resource footprint of fossil fuel-based power plants, the construction phase accounts for the largest part of renewable energy's mineral resource footprint, with the exception of bioenergy.

Source: Wernet et al. (2016), *The Ecoinvent Database Version 3 (Part I): Overview and Methodology*; Ecoinvent (2019), *Version 3.5* (database); calculations and analysis made by BRGM.

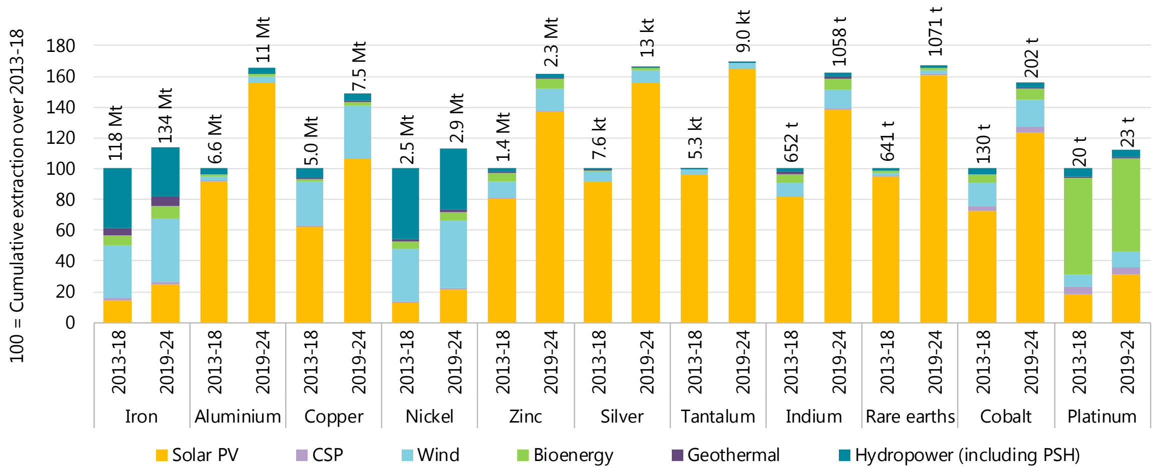
Metals represent only a small share (less than 3%) of the current mineral footprint of the global renewable electricity sector, but they are nonetheless essential for the production of renewable power equipment and infrastructures. Iron is by far the most-used metal for

[49] For fossil fuel and bioenergy plants, this includes the extraction, processing and transportation of fuels.

renewable power, accounting for almost 85% (120 Mt[50]) of the sector's cumulative metal footprint over 2013-18, of which two-thirds was used for steel in hydro and wind power plants together. Aluminium (5%) and copper (4%) are the second and third most mobilised metals, mainly for PV panel manufacturing.

The remaining fraction of the metal footprint includes metals with relatively lower production levels. Some are mined as principal substances such as nickel, zinc, lead, tin and titanium. Others are recovered as by- or coproducts of the formers, such as germanium, gallium, indium, hafnium, tellurium, bismuth and others. Many metals have been identified as "critical raw materials" based on various criteria related to their importance for the economy and supply risks (e.g. EC 2017a; EC, 2017b; UNEP, 2009).[51] As the renewable electricity sector expands, its material footprint on all metals is expected to increase substantially over the outlook period, driven primarily by growth in solar PV and wind capacities (Figure 5.22).

Figure 5.22. Cumulative extraction of selected metals for the renewable electricity sector over 2013-18 and 2019-24



Note: PSH = pumped-storage hydropower.

Source: Wernet et al. (2016), *The Ecoinvent Database Version 3 (Part I): Overview and Methodology*; Ecoinvent (2019), *Version 3.5* database; calculations and analysis made by BRGM.

Although geological availability of mineral resources is not expected to impede deployment of renewable technologies in the near future, tensions in mineral supply chains and higher price volatility may occur over the longer term, depending on substitution opportunities, the evolution of demand for competing applications (e.g. batteries, electronics and electric appliances), geopolitical events, and environmental, social and trade regulations among other factors. Minor metal markets in particular can be highly sensitive to specific technological

[50] In 2018, the iron footprint of the renewable electricity sector amounted to 19 Mt, corresponding to around 1.3% of that year's world iron production (USGS, 2019).

[51] How mineral criticality is defined is evolving, and a variety of methodologies and criteria can be used (Erdmann and Graedel, 2011; Hayes and McCullough, 2018). Among the most common criteria are: supply concentration; reserve-to-production ratio; expected demand growth; substitutability; and recycling restrictions.

choices, and vice versa (for instance, in 2017 cadmium telluride [CdTe] PV was responsible for nearly 40% of tellurium use worldwide [Mineralinfo, 2018]).

While new mining activities will be needed if the renewable power sector is to develop massively – for instance in line with the IEA Sustainable Development Scenario (SDS) – improvements in resource efficiency and product value retention through reuse and recycling will be crucial to mitigate socio-environmental impacts.

Besides, while renewable energy development affects the metal footprint of the energy sector, mining industry energy and water intensities are also likely to increase in the future as a result of exploitation of lower-grade ores. With the mining and quarrying, iron and steel, and non-ferrous metal industries together already accounting for more than 7% of total final energy consumed globally in 2017, the energy-resource-environment nexus warrants careful consideration.

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6. Data tables

Table 6.1. Total renewable electricity capacity (GW)

	Main case							Acc. case
	2018	2019	2020	2021	2022	2023	2024	2024
World	2501	2699	2907	3101	3296	3508	3721	4 036
China	730	804	890	967	1044	1132	1219	1 310
Europe	595	626	658	690	725	765	804	865
Belgium	10	11	12	12	13	13	14	15
Denmark	9	10	10	11	11	12	12	13
France	53	56	59	62	66	73	80	93
Germany	126	131	137	144	151	159	166	184
Italy	57	58	60	61	63	66	68	70
Netherlands	10	13	17	20	24	27	31	36
Poland	10	10	11	12	14	15	16	19
Spain	52	57	63	67	72	76	81	89
Sweden	30	31	32	33	34	35	36	37
Turkey	42	45	49	51	55	59	63	69
United Kingdom	48	50	52	54	56	60	63	64
Asia-Pacific	389	433	476	518	559	598	637	714
Australia	25	30	35	38	40	42	45	49
India	123	139	156	176	197	216	235	272
Indonesia	9	10	10	11	12	13	14	17
Japan	114	123	130	136	142	147	153	159
Korea	19	22	25	29	33	37	41	48
Pakistan	13	14	16	18	19	21	22	29
Philippines	7	8	8	8	9	9	10	12
Thailand	12	12	13	14	14	14	15	16
Vietnam	19	24	25	26	27	27	27	33
North America	401	428	458	482	506	532	558	590
Canada	100	100	102	103	104	105	107	110
Mexico	22	25	28	30	32	36	40	44

	Main case							Acc. case
	2018	2019	2020	2021	2022	2023	2024	2024
United States	280	303	328	349	370	391	411	437
Central and South America	226	235	242	249	255	262	272	281
Argentina	14	16	18	19	20	21	22	25
Brazil	134	139	142	145	147	151	156	161
Chile	11	12	13	14	15	15	16	17
Eurasia	90	96	99	102	105	107	109	114
Russia	53	54	55	56	57	57	57	60
Ukraine	9	12	14	15	16	16	17	19
Sub-Saharan Africa	40	42	45	49	53	57	62	70
Ethiopia	4	5	5	5	7	9	10	12
Ghana	2	2	2	2	2	2	2	2
Kenya	2	2	2	3	3	3	3	5
Nigeria	2	2	2	3	3	3	3	3
South Africa	8	9	10	10	11	11	11	14
Tanzania	1	1	1	1	1	1	1	2
MENA	31	36	39	43	48	54	60	93
Egypt	5	6	7	7	8	9	10	14
Iran	13	13	13	14	14	14	15	18
Israel[52]	1	2	3	3	4	4	5	6
Morocco	4	4	5	5	6	7	8	11
Saudi Arabia	0	0	1	1	2	2	3	18
United Arab Emirates	1	2	3	4	5	6	7	11

Notes: MENA = Middle East and North Africa; GW = gigawatt. Acc. = Accelerated. Capacity data are generally presented as cumulative installed capacity, irrespective of grid-connection status. Renewable electricity capacity includes capacity from bioenergy, hydropower (including pumped storage), onshore and offshore wind, solar PV, solar CSP, geothermal, and ocean technologies. Grid-connected solar PV capacity (including small-distributed capacity) is counted at the time that the grid connection is made, and off-gird solar PV systems are included at the time of the installation. Please refer to regional definitions in the glossary. Specific sources are referenced where data for individual technologies are presented in previous chapters.

[52] The statistical data for Israel are supplied by and under the responsibility of the relevant Israeli authorities. The use of such data by the IEA/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.

Table 6.2. Total renewable electricity generation (TWh)

	2018e	2019	2020	2021	2022	2023	2024	CAAGR
World	6 707	7 076	7 542	7 991	8 387	8 783	9 168	5%
China	1 856	2 001	2 159	2 325	2 479	2 631	2 774	7%
Europe	1 352	1 391	1 498	1 583	1 647	1 718	1 787	5%
Belgium	17	20	22	24	25	26	27	8%
Denmark	21	24	26	28	31	32	33	8%
France	113	110	118	126	130	138	149	5%
Germany	227	238	245	253	262	272	284	4%
Italy	115	112	120	122	125	128	131	2%
Netherlands	19	22	31	38	44	50	56	20%
Poland	21	24	25	27	29	31	34	8%
Spain	104	92	109	127	136	145	155	7%
Sweden	89	93	103	105	106	108	111	4%
Turkey	97	116	125	133	141	149	158	8%
United Kingdom	111	122	128	141	148	160	165	7%
Asia-Pacific	889	965	1 046	1 134	1 214	1 288	1 359	7%
Australia	45	50	58	67	71	74	77	10%
India	288	320	350	385	422	461	497	9%
Indonesia	33	35	37	39	42	45	48	6%
Japan	182	189	199	207	212	217	221	3%
Korea	22	29	35	41	47	53	59	18%
Pakistan	44	53	55	59	64	66	69	8%
Philippines	23	23	24	25	26	27	28	3%
Thailand	29	32	34	36	37	38	39	5%
Vietnam	74	79	86	89	91	93	93	4%
North America	1 230	1 266	1 335	1 402	1 454	1 503	1 555	4%
Canada	424	435	443	448	453	456	460	1%
Mexico	56	59	69	75	80	85	94	9%
United States	750	772	822	879	922	962	1 001	5%
Central and South America	883	928	955	975	993	1 012	1 034	3%
Argentina	42	44	48	52	55	58	59	6%
Brazil	495	533	548	557	563	571	581	3%
Chile	38	38	41	44	46	48	49	4%

	2018e	2019	2020	2021	2022	2023	2024	CAAGR
Eurasia	302	307	314	319	324	329	333	2%
Russia	192	192	194	195	198	198	199	1%
Ukraine	12	15	17	18	20	21	22	10%
Sub-Saharan Africa	144	157	166	175	188	202	217	7%
Ethiopia	14	15	16	17	21	28	35	16%
Ghana	6	7	8	8	8	8	8	3%
Kenya	9	11	12	12	14	15	16	10%
Nigeria	5	5	6	7	8	9	9	9%
South Africa	12	13	13	15	17	19	19	8%
Tanzania	3	3	3	3	3	3	3	3%
MENA	51	61	70	78	88	98	109	13%
Egypt	16	19	21	22	23	24	26	9%
Iran	17	17	18	19	19	20	21	4%
Israel[53]	2	3	4	5	6	7	8	27%
Morocco	7	8	10	11	13	16	18	18%
Saudi Arabia	0	1	1	1	2	3	4	65%
United Arab Emirates	1	3	6	7	10	12	14	53%

Notes: TWh = terawatt hour. Generation data refer to gross electricity production and include electricity for own use. Renewable electricity generation includes generation from bioenergy, hydropower (including pumped storage), onshore and offshore wind, solar PV, solar CSP, geothermal, and ocean technologies. Generation from bioenergy includes generation from solid, liquid and gaseous biomass (including cofired biomass), and the renewable portion of municipal waste. The time series for onshore and offshore wind generation is estimated because wind generation data are only available at the aggregate level. CAAGR = compound average annual growth rate. Please refer to regional definitions in the glossary. For OECD member countries, 2018 generation data are based on IEA statistics published in Renewables Information 2019.

[53] The statistical data for Israel are supplied by and under the responsibility of the relevant Israeli authorities. The use of such data by the IEA/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.

Table 6.3. Distributed PV capacity (GW)

	Main case							Acc. case
	2018	2019	2020	2021	2022	2023	2024	2024
World	213	258	305	354	407	466	530	619
China	51	71	92	115	141	171	205	237
Europe	79	87	95	103	111	120	130	150
Belgium	4	4	4	5	5	5	6	6
Denmark	1	1	1	1	1	1	1	2
France	5	5	6	7	8	9	11	13
Germany	33	36	38	41	43	46	48	57
Italy	16	16	17	17	18	18	19	20
Netherlands	4	5	7	8	10	11	13	16
Poland	0	1	1	2	2	2	3	3
Spain	4	4	5	5	6	6	7	8
Turkey	1	1	1	2	2	3	4	5
Asia-Pacific	50	60	71	81	92	102	112	139
Australia	8	9	11	12	14	16	17	19
India	4	7	9	12	16	19	22	36
Indonesia	0	0	0	0	0	0	1	1
Japan	34	39	43	46	49	52	54	57
Korea	1	2	2	3	4	6	7	9
Pakistan	0	0	0	0	1	1	1	5
Thailand	0	0	0	1	1	1	1	2
North America	27	31	37	42	48	54	62	67
Mexico	1	1	1	2	2	3	4	5
United States	25	29	34	39	44	50	56	61
Central and South America	1	2	2	3	4	5	7	8
Argentina	0	0	0	0	0	0	1	1
Brazil	0	1	1	2	3	4	5	5
Chile	0	0	0	0	0	0	1	1
Eurasia	1	3	4	5	5	6	6	7
Sub-Saharan Africa	1	1	1	2	2	2	3	4
MENA	2	2	3	3	4	4	5	9

Notes: MENA = Middle East and North Africa; GW = gigawatt. Acc. = Accelerated. Capacity data are generally presented as cumulative installed capacity, irrespective of grid-connection status. Renewable electricity capacity includes capacity from bioenergy, hydropower (including pumped storage), onshore and offshore wind, solar PV, solar CSP, geothermal, and ocean technologies. Grid-connected solar PV capacity (including small-distributed capacity) is counted at the time that the grid connection is made, and off-gird solar PV systems are included at the time of the installation. Please refer to regional definitions in the glossary. Specific sources are referenced where data for individual technologies are presented in previous chapters.

Table 6.4. Total renewable electricity capacity by technology (GW)

	Main case							Acc. case
	2018	2024	2020	2021	2022	2023	2024	2024
Hydropower	1 290	1 308	1 337	1 357	1 373	1 394	1 411	1 447
Pumped storage	155	158	163	167	171	176	181	202
Bioenergy	130	138	146	152	159	165	171	187
Wind	565	622	686	744	799	857	917	996
Onshore wind	543	595	654	704	753	802	851	920
Offshore wind	22	27	32	39	46	55	66	77
Solar PV	496	609	716	823	939	1 064	1 195	1 374
PV - Utility	283	352	411	469	532	598	665	754
PV - Distributed	213	258	305	354	407	466	530	619
CSP	6	6	7	8	9	9	9	12
Geothermal	14	15	15	16	17	18	18	20
Marine	1	1	1	1	1	1	1	1
Total	2 501	2 699	2 907	3 101	3 296	3 508	3 721	4 036

Notes: GW = gigawatt. Acc. = Accelerated. Capacity data are generally presented as cumulative installed capacity, irrespective of grid-connection status. Renewable electricity capacity includes capacity from bioenergy, hydropower (including pumped storage), onshore and offshore wind, solar PV, solar CSP, geothermal, and ocean technologies. Grid-connected solar PV capacity (including small-distributed capacity) is counted at the time that the grid connection is made, and off-gird solar PV systems are included at the time of the installation. Please refer to regional definitions in the glossary. Specific sources are referenced where data for individual technologies are presented in previous chapters.

Table 6.5. Total renewable electricity generation by technology (TWh)

	2018e	2019	2020	2021	2022	2023	2024	CAAGR
Hydropower	4 203	4 258	4 385	4 483	4 537	4 591	4 648	2%
Pumped storage	115	125	129	134	139	144	149	4%
Bioenergy	546	599	640	683	715	746	761	6%
Wind	1 268	1 389	1 534	1 698	1 852	1 998	2 135	9%
Onshore wind	1 202	1 307	1 433	1 571	1 697	1 808	1 921	8%
Offshore wind	66	82	101	126	155	190	214	22%
Solar PV	585	720	864	1 005	1 151	1 309	1 480	17%
CSP	13	16	18	20	25	26	26	12%
Geothermal	90	94	98	101	106	111	116	4%
Marine	1	1	1	1	1	1	1	3%
Total	6 707	7 076	7 542	7 991	8 387	8 783	9 168	5%

Notes: TWh = terawatt hour. Generation data refer to gross electricity production and include electricity for own use. Renewable electricity generation includes generation from bioenergy, hydropower (including pumped storage), onshore and offshore wind, solar PV, solar CSP, geothermal, and ocean technologies. Generation from bioenergy includes generation from solid, liquid and gaseous biomass (including cofired biomass), and the renewable portion of municipal waste. The time series for onshore and offshore wind generation is estimated because wind generation data are only available at the aggregate level. CAAGR = compound average annual growth rate. Please refer to regional definitions in the glossary.For OECD member countries, 2018 generation data are based on IEA statistics published in Renewables Information 2019

Table 6.6. Ethanol production (billion litres)

	Main case							Acc. case
	2018	2019	2020	2021	2022	2023	2024	2024
World	110	111	114	120	124	126	130	155
North America	63	62	62	64	64	64	64	71
Canada	2	2	2	2	2	2	2	3
United States	61	60	60	62	62	62	62	67
EU28	5	5	6	5	5	5	5	8
France	1	1	1	1	1	1	1	1
Germany	1	1	1	1	1	1	1	1
Eurasia	0	0	0	0	0	0	0	0
China	3	4	5	7	9	10	11	21
Asia-Pacific	4	4	5	5	6	7	7	10
India	2	2	2	2	3	3	4	6
Thailand	1	2	2	2	2	2	2	3
Latin America	34	34	35	37	38	39	41	44
Argentina	1	1	1	1	1	1	1	2
Brazil	32	32	32	34	35	36	38	40
Africa	0	0	0	1	1	1	1	1
Rest of World	0	0	0	0	0	0	0	1

Notes: Production presented in volume; to convert to energy an approximate calorific value of 21 MJ/litre can be used. Acc. = Accelerated. Latin America excludes Mexico which is included in North America

Table 6.7. Biodiesel and HVO production (billion litres) forecast

	Main case							Acc. case
	2018	2019	2020	2021	2022	2023	2024	2024
World	43	47	50	52	55	56	57	70
North America	8	10	10	11	13	13	13	16
Canada	0	0	0	0	0	0	0	0
United States	8	9	10	11	12	13	13	16
EU28	15	16	17	16	16	16	16	19
France	3	3	3	3	3	3	3	3
Germany	3	3	3	3	3	3	3	3
Eurasia	0	0	0	0	0	0	0	0
China	1	1	1	2	2	2	2	3
Asia-Pacific	9	10	12	12	14	14	15	17
Malaysia	1	1	1	1	1	1	1	2
Indonesia	4	6	6	7	7	7	8	9
Latin America	9	9	9	10	10	10	10	12
Argentina	3	3	3	3	2	2	2	3
Brazil	5	5	5	6	6	7	7	8
Africa	0	0	0	0	0	0	0	0
Rest of World	0	0	0	0	0	0	0	2

Notes: Production presented in volume; to convert to energy an approximate calorific value of 21 MJ/litre can be used. Acc. = Accelerated.

Latin America excludes Mexico which is included in North America

Annexes

Glossary

Regional and country groupings

Association of Southeast Asian Nations (ASEAN)

Brunei, Cambodia, Indonesia, Lao People's Democratic Republic (Lao PDR), Malaysia, Myanmar, Philippines, Singapore, Thailand and Viet Nam.

Asia and Pacific

Australia, Bangladesh, Brunei, Cambodia, India, Indonesia, Japan, Korea, Lao PDR, Malaysia, Mongolia, Myanmar, Nepal, New Zealand, Pakistan, Philippines, Singapore, Sri Lanka, Thailand, Viet Nam.

China

Refers to the People's Republic of China, including Hong Kong.

Europe

Austria, Albania, Belgium, Bulgaria, Croatia, Cyprus[54], Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Iceland, Montenegro, Ireland, Italy, Latvia, Lithuania, Luxembourg, Malta, Netherlands, Norway, Poland, Portugal, Romania, Serbia, Slovak Republic, Slovenia, Spain, Sweden, Switzerland, Turkey and United Kingdom.

Eurasia

Albania, Armenia, Azerbaijan, Belarus, Bosnia and Herzegovina, Georgia, Gibraltar, Kazakhstan, Kosovo, Kyrgyzstan, Moldova, Montenegro, Republic of North Macedonia, Russian Federation, Serbia, Tajikistan, Turkmenistan, Ukraine.

Middle East and North Africa (MENA)

Algeria, Bahrain, Egypt, Iran, Iraq, Israel, Jordan, Kuwait, Lebanon, Libya, Morocco, Oman, Qatar, Saudi Arabia, Syria, Tunisia, United Arab Emirates and Yemen.

[54] Note by Turkey
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. Turkey recognises the Turkish Republic of Northern Cyprus (TRNC). Until a lasting and equitable solution is found within the context of the United Nations, Turkey 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 Turkey. The information in this document relates to the area under the effective control of the Government of the Republic of Cyprus.

North America

Canada, Mexico and the United States.

Latin America

Argentina, Plurinational State of Bolivia (Bolivia), Brazil, Colombia, Costa Rica, Cuba, Curacao, Dominican Republic, Ecuador, El Salvador, Guatemala, Haiti, Honduras, Jamaica, Nicaragua, Panama, Paraguay, Peru, Suriname, Trinidad and Tobago, Uruguay, Bolivarian Republic of Venezuela (Venezuela).

Sub-Saharan Africa (SSA)

Angola, Benin, Botswana, Cameroon, Congo, Democratic Republic of Congo, Côte d'Ivoire, Eritrea, Ethiopia, Gabon, Ghana, Kenya, Mauritius, Mozambique, Namibia, Niger, Senegal, South Africa, South Sudan, Sudan, United Republic of Tanzania, Togo, Zambia, Zimbabwe, and other African countries (Burkina Faso, Burundi, Cape Verde, Central African Republic, Chad, Comoros, Djibouti, Equatorial Guinea, Gambia, Guinea, Guinea-Bissau, Kingdom of Eswatini Lesotho, Liberia, Madagascar, Malawi, Mauritania, Rwanda, Sao Tome and Principe, Seychelles, Sierra Leone, Somalia, Uganda).

List of acronyms, abbreviations and units of measure

Acronyms and abbreviations

Acc.	Accelerated case
AC/DC	Alternating current/Direct current
ACE	Affordable Clean Energy (United States)
ANP	National Association of Petrol, Natural Gas and Biofuels
APAC	Asia and Pacific
ASEAN	Association of Southeast Asian Nations
BNDES	Brazilian National Development Bank
BSRIA	Building Services Research and Information Association
CAAGR	Compound average annual growth rate
CEL	Clean energy certificate (Mexico)
CEEW	Council on Energy, Environment, and Water
CfD	Contract for Difference (United Kingdom)
CO_2	Carbon dioxide
CPP	Clean Power Plan (United States)
CPSU	Central public sector undertakings
CSP	Concentrated solar power
DISCOM	Distribution company (India)
EGEC	European Geothermal Energy Council
EHPA	European Heat Pump Association
EIA	United States Energy Information Administration
EOR	Enhanced oil recovery
EPA	United States Environmental Protection Agency
EPC	Engineering, Procurement and Construction
EfW	Energy from waste
ERCOT	Electricity Reliability Council of Texas
EU	European Union
FAME	Fatty Acid Methyl Ester
FFV	Flexible fuel vehicles
FIT	Feed-in tariff
FYP	Five-Year Plan (China)
GHG	Greenhouse gas
GSHP	Ground source heat pumps
GST	Goods and service tax

HEFA	Hydroprocessed esters and fatty acids
HVO	Hydrotreated vegetable oil
IEA	International Energy Agency
IPP	Independent power producers
IRENA	International Renewable Energy Agency
ITC	Investment Tax Credit (United States)
LBNL	Lawrence Berkeley National Lab (United States)
LCOE	Levelised cost of electricity
MAPA	Ministry of Agriculture, Livestock and Food Supply (Brazil)
MENA	Middle East and North Africa
METI	Ministry of Economy, Trade and Industry (Japan)
MNRE	Ministry of New and Renewable Energy
MSW	Municipal solid waste
NDRC	National Development and Reform Commission (China)
NEA	National Energy Administration (China)
NECP	National Energy and Climate Plans (European Union)
OECD	Organisation for Economic Co-operation and Development
PPA	Power purchase agreements
PSH	Pumped storage hydropower
PTC	Production tax incentives (United States)
PURPA	Public Utility Regulatory Policy
PV	Photovoltaics
RE	Renewable energy
REC	Renewable energy certificate
RED	Renewable Energy Directive (European Union)
REIPPPP	Renewable Energy Independent Power Producer Procurement Program (South Africa)
RES	Renewable energy sources
RoW	Rest of the world
RPS	Renewable portfolio standard
SDE	Sustainable Energy Production
SECI	Solar Energy Corporation of India
SHC	Solar heating and cooling
SHIP	Solar heating in industrial processes
SHS	Solar Home Systems
SSA	Sub-Saharan Africa
UCO	Used cooking oil

UDAY	Ujwal DISCOM Assurance Yojana (India)
UK	United Kingdom
UNFCCC	United Nations Framework Convention on Climate Change
UNICA	Brazilian Sugarcane Industry Association
USA	United States of America
VRE	Variable renewable energy
WEO	IEA World Energy Outlook
YEKA	Renewable Energy Resource Areas (Turkey)
y-o-y	Year-on-year

Currency codes

CNY	Chinese yuan
EUR	euro
INR	Indian Rupee
USD	United States dollar

Units of measure

bbl	barrel (of oil)
EJ	exajoule
GW	gigawatt
GWh	gigawatt hour
GWth	gigawatt thermal
kW	kilowatt
kWh	kilowatt hour
L	litre
Mt	million tonnes
MW	megawatt
MWh	megawatt hour
MW_{th}	megawatt thermal
m^2	square metre
PJ	petajoule
t	tonne
TJ	terajoule
TW	terawatts
TWh	terawatt hours
W	watt

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