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RENEWABLES 2018

Analysis and Forecasts to 2023

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FOREWORD

The progress of renewables in the electricity sector is an instructive – and, by now, well known – success story that demonstrates the positive impact of government policies on technology development, deployment, and cost reduction. Wind and solar photovoltaic technologies are becoming increasingly competitive with coal and natural gas-based electricity generation in a growing number of countries.

This success should not, however, obscure the fact that the electricity sector accounts for less than 20% of global energy consumption. The contribution of renewables in heat and transport, which together account for the bulk of global energy demand, remains much lower than in the power sector. Indeed, their role in heat and transport is often overlooked even though decarbonising these sectors is a key priority to achieve our long-term climate and sustainability goals.

The International Energy Agency (IEA) is shining a light on some of the "blind spots" of our energy system – issues that are of crucial importance but that generally receive less attention, such as the soaring demand for electricity for air conditioning and the impact of rising petrochemical demand on oil markets.

This is also the case for modern bioenergy, which is a special focus of this *Renewables 2018* report. Today, modern bioenergy consumption to produce electricity, industrial heat, and transport biofuels is equal to all other renewables combined, including hydropower, wind, and solar energy. Yet the role of modern bioenergy in decarbonising the global energy system is not widely recognised, nor does it receive the attention it deserves.

Our report reveals that bioenergy leads growth in the use of renewables in the global energy mix over the forecast period of 2018-23. In 2023, Bioenergy remains the largest source of renewable energy owing to its widespread use in heat and transport, sectors in which other renewables currently make a far smaller contribution.

Nevertheless, to deliver beneficial outcomes, modern bioenergy expansion must adhere to rigorous sustainability guidelines. Only bioenergy that reduces lifecycle greenhouse gas (GHG) emissions while avoiding unacceptable social, environmental, and economic impacts has a future role in a sustainable energy system. Policy makers therefore need to introduce and implement robust and transparent sustainability frameworks and regulations to govern bioenergy supply and use. The IEA believes this can – and must – happen by building on the successful policy frameworks already in place.

Assuming strong sustainability measures are in force, this report identifies additional untapped potential for bioenergy to "green" the industry and transport sectors. A significant proportion of this potential relies on exploiting biomass waste and residue resources that offer low lifecycle GHG emissions and mitigate land-use change concerns while delivering waste management and air quality benefits.

Reaching the full potential of modern bioenergy would complement the success already achieved for wind and solar technologies. Modern bioenergy can significantly strengthen the renewables portfolio and – most importantly – aid the establishment of a more sustainable and secure energy system, something the world very much needs.

Dr. Fatih Birol
Executive Director
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Questions or comments?

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Modern bioenergy, the overlooked giant of renewables

Bioenergy is a special focus of this year's report. Half of all renewable energy consumed in 2017 came from modern bioenergy, which provided four times the contribution of solar photovoltaic (PV) and wind combined. Most of the modern bioenergy (i.e. excluding the traditional use of biomass) contributing to final energy consumption provides heat in buildings and for industry. The rest is consumed in the transport sector and for electricity.

Bioenergy leads growth in renewable energy consumption over the forecast period of 2018-23. Around 30% of the growth in renewables consumption is expected to come from modern bioenergy in the form of solid, liquid and gaseous fuel due to bioenergy's considerable use in heat and its growing consumption and in transport. Other renewables make a negligible contribution to these two sectors, which together account for 80% of total energy consumption. In 2023, modern bioenergy remains the main renewable energy source, although its share of total renewable energy declines slightly as solar PV and wind expansion accelerate in the electricity sector.

Renewables increasingly central to total energy consumption growth

Global renewable energy consumption increased more than 5% in 2017 – three times faster than total final energy consumption. In the power sector, renewables accounted for half of annual global electricity generation growth, led by wind, solar PV, and hydropower.

The share of renewable technologies meeting global energy demand is expected to increase by a fifth, reaching 12.4% in 2023 – a faster rate of progress than in the 2012-17 period. Renewables cover 40% of global energy consumption growth over the forecast period. Their use continues to increase most rapidly in the electricity sector, reaching 30% of total world electricity generation in 2023. But because of weaker policy support and additional barriers to deployment, renewables use expands far more slowly in the transport and heat sectors.

Brazil has the greenest energy mix, but the People's Republic of China leads absolute growth. Of the world's largest energy consumers, Brazil uses the highest share of renewables by far – almost 45% of total final energy consumption in 2023. Bioenergy consumption in transport and industry is significant, and hydropower dominates the electricity sector. Meanwhile, as a result of policies to decarbonise all sectors and reduce harmful local air pollution, China[1] leads global growth in absolute terms during the forecast period, and surpasses the European Union to become the largest consumer of renewable energy. In the European Union, a greater share of renewables is spurred by binding renewable energy targets for 2020 and 2030 as well as by country-level policies and improved energy efficiency. Bioenergy drives renewable energy growth in India due its prominent role in industry followed by rapid solar PV and wind expansion.

Solar PV dominates renewable electricity capacity expansion

Once again, 2017 was a record year for renewable power. For the first time, renewable capacity additions of 178 gigawatts (GW) accounted for more than two-thirds of global net electricity capacity growth. Solar PV capacity expanded the most (97 GW), over half of which was in China. Meanwhile, onshore wind additions declined for the second year in a row, and hydropower growth continued to decelerate.

[1] "China" is used throughout to denote the People's Republic of China.

Solar PV capacity expands almost 600 GW – more than all other renewable power technologies combined, or as much as twice Japan's total capacity, reaching 1 terawatt (TW) by the end of the forecast period. Despite recent policy changes, China remains the absolute solar PV leader by far, holding almost 40% of global installed PV capacity in 2023.

Distributed generation makes the difference in solar PV growth. The expansion of distributed generation, led by commercial and industrial projects, and followed by residential applications, spurs almost half of global PV capacity growth over 2018-23. Homes, businesses and large industrial applications are expected to generate almost 2% of global electricity output by 2023. Without distributed generation, solar PV growth would be comparable to that of wind expansion.

Wind is the second-largest contributor to renewable capacity growth, while hydropower remains the largest renewable electricity source by 2023. Similar to last year's forecast, wind capacity is expected to increase 60% (325 GW), with offshore wind accounting for 10% of this expansion. Growth prospects for both hydropower and bioenergy are more optimistic than last year, mostly as a result of developments in China.

China continues to be the largest growth market for all renewable electricity sources except geothermal and marine as it is responsible for over 40% of global capacity expansion in the 2018-23 period. Despite recent policy changes in renewable support schemes to achieve a more cost-effective expansion and to address grid integration challenges, China is expected to comfortably exceed newly introduced renewable portfolio standard (RPS) targets by 2020 as wind and solar PV technologies become more competitive.

The European Union's capacity growth overtakes the United States to become the second-largest growth market after China, with 125 GW of renewable power capacity coming online in 2018-23. This optimistic forecast is based on: approval of the EU-wide target of 32% renewable energy by 2030; the introduction of additional competitive auctions for long-term power purchase agreements (PPAs) in key countries; and a growing corporate PPA market that takes advantage of wind and solar PV cost reductions. Although US renewable capacity is expected to grow 44%, recent changes to the federal tax code, trade policies and energy plans have introduced downside forecast uncertainties. A doubling of India's renewable capacity is anticipated, mostly in solar PV and onshore wind. This is similar to last year's forecast as challenges involving grid integration and the financial health of distribution companies hamper faster growth. Renewables growth accelerates in many other regions, from Latin America to sub-Saharan Africa.

A policy shift towards competitive pricing mechanisms drives renewables growth. For the first time, more than half of renewable electricity capacity is expected to be commissioned through competitive auctions, which continue to slash wind and solar PV bid prices to between USD 20 per megawatt hour (MWh) and USD 50/MWh. For offshore wind, the decline of almost two-thirds that is expected over the forecast period will also improve future prospects for the production of hydrogen, especially in Europe. Overall, continuous cost reductions are expected to make renewables more competitive with new coal and natural gas plants in an increasing number of countries.

Renewable heat potential remains untapped, demanding greater policy attention

Renewable heat consumption is higher than that of renewable electricity in absolute terms, but still represents only 10% of global heat demand. Heat accounts for the largest portion of energy end-use (52% of final energy consumption), given its use for heating buildings and water, for cooking, and for industrial processes. Modern bioenergy, which dominates renewable heat consumption, accounted for over 70% of directly used renewable heat in 2017 as well as most of the renewable heat used for district heating.

Renewable heat consumption is expected to increase 20%, capturing over one-third of global heat demand growth. China, the European Union, the United States and India together account for most of renewable heat growth. China's renewable heat consumption surpasses that of the United States, making it the largest consumer by 2023. Renewable heat shares also continue to expand steadily in member states of the European Union, supported by policies and by the decline in overall heat demand as energy efficiency rises.

Modern bioenergy consumption in the industry sector is anticipated to increase 13%. The use of biomass and waste fuels in the cement subsector is expected to grow almost 40%. However, the potential for further expansion is considerable, as demonstrated by the EU cement industry in which bioenergy and waste meet one-quarter of energy demand in accordance with robust waste management policies. With the exception of pulp and paper, in other energy-intensive industries, bioenergy is expected to make only a minimal contribution.

Renewable electricity for heat is the second-largest contributor to renewable heat growth over the forecast period, owing to two trends: 1) the use of electricity to produce heat is increasing at a faster rate than total heat consumption growth; and 2) the share of renewables in the electricity sector is expanding rapidly. Electrification of industrial processes is also gaining in popularity, while the use of heat pumps in buildings is becoming more widespread.

Biofuels and electric mobility emerge as complementary options in transport

Biofuel production continues to increase, rising 15% to 165 billion litres (L) by the end of the forecast period. However, biofuels only represent less than 4% of total transport energy demand in 2023. Even though electric mobility expands rapidly, biofuels still hold an almost 90% share of total renewables in transport sector energy demand in 2023. Fuel ethanol makes up two-thirds of biofuel production growth, and biodiesel and hydrotreated vegetable oil (HVO) provide the remainder.

Asia and Latin America dominate biofuel production growth. Half of global production growth is forecast to happen in Asian countries, mainly China, India and ASEAN,[2] where ample feedstocks and the desire to increase security of supply have resulted in greater policy support. Meanwhile, Brazil delivers the largest absolute increase in biofuels output of any country over the forecast period. US ethanol production is forecast to decline slightly owing to greater vehicle fleet efficiency, limited investment in new capacity, and attainment of the allowable limit for corn ethanol under the current policy scheme.

2020 is expected to be a pivotal year for biofuel policies as Brazil and China introduce policy schemes anticipated to significantly boost market prospects. Brazil's flagship RenovaBio policy is expected to strengthen the economics of biofuel production, accelerating investment in new capacity and output from existing plants. In addition, China is extending its 10% ethanol-blending mandate nationwide, resulting in a notable upward revision of the forecast. By 2020, India's recently announced biofuels policy is also anticipated to result in higher biofuel production. However, the turning of the decade coincides with weakening EU policy support for conventional biofuels.

Despite stronger policy support, advanced biofuel production remains low. Several advanced biofuel plants that use newer technologies are under construction or announced, mostly in Europe, India and the United States, where supportive policy frameworks are in place. However, without enhanced policy support, novel advanced biofuels account for only 1% of all biofuel output by 2023. Biofuel demand in the aviation

[2] Association of Southeast Asian Nations.

sector is growing, mostly driven by voluntary initiatives. However, despite the availability of some technically mature fuels, production of aviation biofuels is expected to remain constrained unless production costs decrease or policy support is strengthened.

Renewable electricity in transport is anticipated to expand by two-thirds. Electric cars, two- and three- wheelers, and buses lead this growth; their electricity consumption almost triples over the forecast period. However, rail still accounts for the majority of renewable consumption in 2023. Overall renewables provide almost one-third of global electrified transport demand by the end of the forecast period.

Policies continue to remain critically important for the future of renewables

To meet long-term climate and other sustainability goals, renewable energy development in the heat, electricity and transport sectors must accelerate. Should progress continue at the pace currently forecast, the share of renewables in final energy consumption would be roughly 18% by 2040 – significantly below the International Energy Agency (IEA) Sustainable Development Scenario's benchmark of 28%.

Renewables expansion in the electricity sector could be 25% higher under the IEA accelerated case. Even with renewable energy technologies becoming increasingly competitive, appropriate policies and market design are critical. The accelerated case assumes that governments introduce measures to tackle policy and regulatory uncertainties as well as grid integration and financing challenges before 2020. China, the European Union, India and the United States together account for almost two-thirds of potential upside in the accelerated case. As a result, renewable capacity growth could reach 1.3 TW over 2018-23, putting the renewable electricity sector fully on track to meet long-term climate and sustainability goals.

With the more favourable market and policy conditions assumed under the accelerated case, global transport biofuel output could be 25% higher than in the main case. Stronger implementation of blending mandates would boost ethanol production by over 20%, with Brazil, China and the United States making the greatest contributions. Biodiesel and HVO output could climb more than 30%, mainly in Brazil, India and ASEAN. Novel advanced biofuel technologies that use non-food crops, wastes and residues for feedstocks could expand by two-thirds, assuming a higher proportion of announced projects become operational.

Untapped potential to increase bioenergy use in the cement subsector as well as the sugar and ethanol industry is significant. Cement production holds the largest potential as two-thirds of the bioenergy used in this industry is from waste. Robust waste management in key cement-producing countries could therefore double the share of energy demand met by bioenergy and waste to 13% by 2023. In the sugar and ethanol industry, renewable energy generation could rise significantly if all sugar cane-cultivating countries exploited the potential of high-efficiency co-generation, sugar cane straw and new energy cane varieties.

Bioenergy growth in the heat, transport and electricity sectors combined could be as considerable as that of other renewables in the electricity sector. A significant proportion of this potential relies on wastes and residues that offer low lifecycle greenhouse gas (GHG) emissions and mitigate concerns over land-use change. In addition, using these resources can improve waste management and air quality.

Robust sustainability frameworks are key to bioenergy growth. Only bioenergy that reduces lifecycle GHG emissions while avoiding unacceptable social, environmental and economic impacts has a future role in decarbonising the energy system. Robust sustainability governance and enforcement must therefore be a central pillar of any bioenergy support policy.

1. GLOBAL OVERVIEW

Highlights

- In 2017, global renewable energy consumption increased 5% year-on-year (y-o-y). Bioenergy remained the largest source of renewable consumption (50%), owing to its widespread use in the heat, electricity and transport sectors. Hydro, wind and solar photovoltaic (PV) energy followed. The share of renewables in final energy consumption rose an estimated 0.3 percentage points to 10.4%.
- Support policies have been critical for expanding renewable energy consumption globally, although the evolution of renewables policies has varied significantly among regions and sectors. Over 2010-17, the number of countries supporting renewable electricity doubled to 120, and those introducing biofuel mandates almost tripled to 90. Meanwhile, progress in the heat sector remains limited with only 22 countries having mandates in 2017.
- The share of renewables is expected to increase two percentage points to 12.4% in 2023, a greater increase than in the previous six-year period. Renewable energy consumption expands 27% over the forecast period (2018-23), with bioenergy providing 30% of the increase. It remains the largest renewable energy source in 2023 because of its considerable use in heat and transport, which together account for 80% of total energy consumption globally. Wind registers the second-largest growth, followed by solar PV and hydropower. Although most renewable energy expansion occurs in the electricity sector, heat remains the largest end user of renewables in 2023.
- People's Republic of China[1] leads global renewable energy growth over 2018-23, driven by policies aimed at decarbonising all sectors and reducing local air pollution, and it surpasses the European Union to become the largest consumer of renewable energy globally by 2023. Among the world's largest energy consumers, Brazil is forecast to retain one of the highest shares of renewables in 2023, thanks to considerable bioenergy consumption in both the transport and industry sectors, and the dominance of hydropower in electricity generation.
- The electricity sector demonstrates the most rapid renewable energy share growth, from a 25% share in 2017 to 30% in 2023. Renewable technologies are forecast to supply over 70% of global electricity generation growth in this period, led by solar PV and followed by wind, hydropower and bioenergy. Hydropower remains the largest renewable electricity source in 2023 (53%), followed by wind (22%), solar PV (15%) and bioenergy (9%).
- The share of renewables in the heat sector continues its modest growth, going from 10% to 12% over the period 2018-23. Renewables meet one-third of the global growth in heat demand, mostly through bioenergy and renewable electricity in heating.
- Among the three sectors, the renewables contribution in transport is the lowest (3.4% in 2017) and grows the most slowly (less than one percentage point to 3.8% in 2023). This is the result of ongoing petroleum product consumption, as renewables supply only 12% of all energy demand growth over the forecast period. Of the renewable energy used in transport, biofuels still make up almost 90% in 2023, and the remainder is renewable electricity for rail and road use.

[1] Hereafter "China".

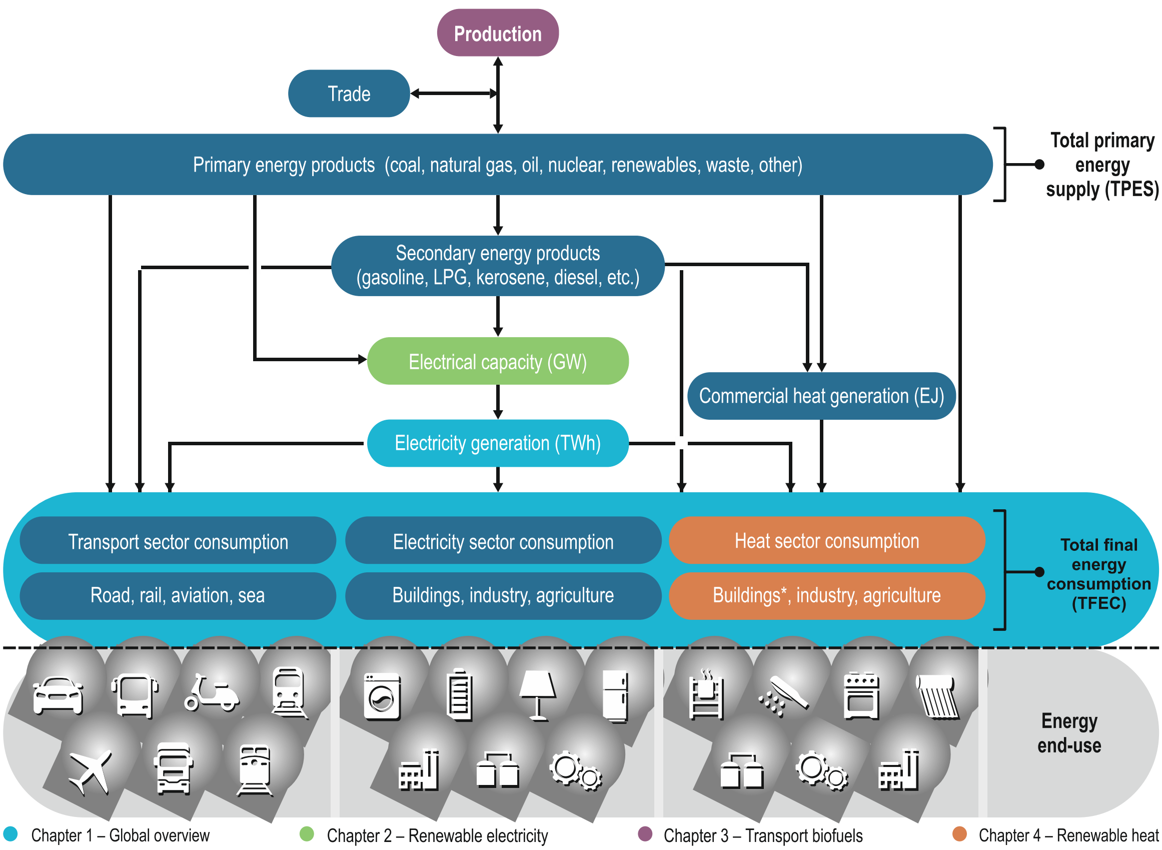
Recent deployment trends

Global renewable energy[2] consumption (Box 1.1), excluding traditional biomass use, continued to increase in 2017, up 5% relative to 2016, driving the share of renewables up to a record high of 10.4%. Wind grew the most, followed closely by bioenergy. Over half of bioenergy's expansion was in heating applications, and the other half was split between the transport and power sectors (Figure 1.2, left).

Box 1.1 Quantifying renewable energy consumption

Quantifying renewable energy within the energy system can occur at various points between when it is produced to when it is finally consumed as a useful energy service. In this report, the amount of renewable energy within the energy system is quantified at the level of total final energy consumption (TFEC). This level corresponds to energy consumed in the industry, buildings, transport, and other sectors such as agriculture and fishing, and non-energy use is excluded. This metric was chosen in order to conform to the indicator used in the United Nation's Sustainable Development Goals (SDG) 7.2 to monitor the global share of renewables (UN, 2017).[3]

Figure 1.1 Energy production and consumption flow chart



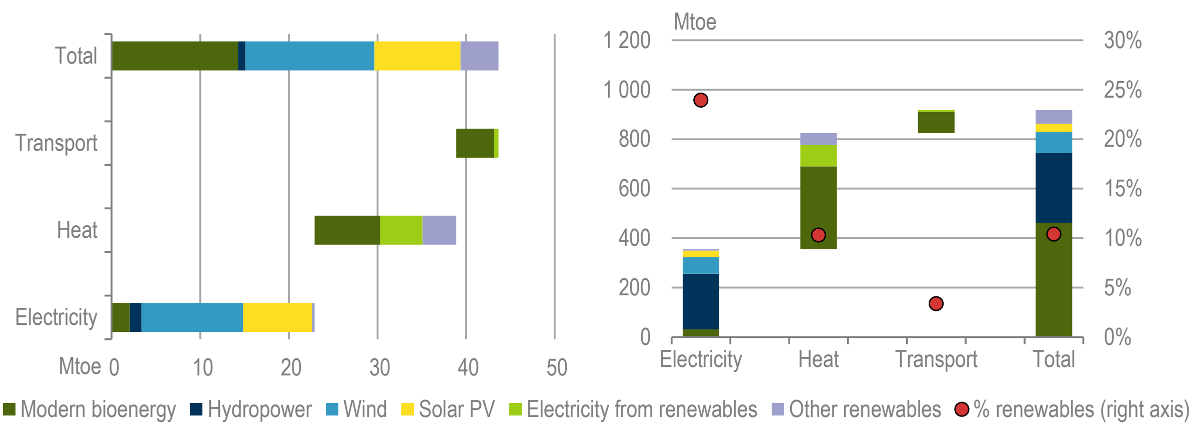
[2] *This report excludes electricity from pumped storage hydropower and energy from the traditional use of biomass.

[3] This metric is calculated per the methodology qualitatively described in the SDG Indicator Metadata (UN, 2018), which also corresponds to that quantitatively described in Annex 3 of the *Sustainable Energy For All Global Tracking Framework* (SE4ALL, 2015).

Because of its high penetration across all three of these end-use sectors, bioenergy also remained the largest source of renewable energy in absolute terms in 2017, accounting for 50% of all renewable energy consumption. At the sectoral level, however, most renewables growth from 2016 to 2017 was concentrated in electricity generation. Variable renewable sources (i.e. wind and solar PV) supplied most of the additional renewable electricity generated, which was driven by strong capacity expansions in China particularly, as well as in the United States, the European Union and India.

Across the sectors, renewables continued to have the largest penetration in electricity, accounting for 24% of total electricity consumption in 2017. Yet electricity is responsible for only one-fifth of total final energy consumption. Therefore, despite gains in the electricity sector, the share of renewables in overall final consumption was much lower at 10.4% due to lower shares and less progress in other sectors. Heat and transport account for over 80% of final energy consumption and their renewables shares (10% in heat and 3% in transport) remained substantially lower than for electricity, highlighting the need for greater policy attention in these sectors that are more difficult to decarbonise (Figure 1.2, right).

Figure 1.2 Modern renewable energy consumption: Annual growth, 2017 (left), and total consumption, 2017 (right)



Notes: Mtoe = million tonnes of oil equivalent; RES = renewable energy sources. RES includes modern bioenergy, hydro, solar, wind, geothermal and marine. Electricity from renewables mean renewable portion of electricity used in heating and transport. Other renewables include solar thermal, geothermal, and marine technologies.

Sources: IEA (2018), *World Energy Statistics and Balances 2018* (database), www.iea.org/statistics; IEA analysis.

Box 1.2 What is the traditional use of biomass?

The "traditional use of biomass" refers to the use of local solid biomass resources by low-income households that do not have access to modern cooking and heating fuels or technologies. Solid biomass, such as wood, charcoal, agricultural residues and animal dung, is converted into energy through basic techniques, such as a three-stone fire, for heating and cooking in the residential sector. Such consumption occurs principally in emerging economies and developing countries.[4]

[4] Biomass can also be used at low efficiency in developed countries, e.g. fireplace combustion of split logs.

This use of biomass resources tends to have very low conversion efficiency (5-15%) and, as local demand can also exceed sustainable supply, can often result in negative environmental impacts. In addition, high particulate matter (PM) emissions and other air pollutants are produced. When combined with poor ventilation, such pollutants result in household indoor air pollution, which is responsible for a range of severe health conditions and is a leading cause of premature deaths. As a result, policy attention focuses on reducing the traditional use of biomass and encouraging the adoption of more sophisticated heating and cooking technologies.

Therefore, even though traditional use of biomass is a renewable source, it is outside the scope of *Renewables 2018*, and is excluded from our renewable energy accounting. This report only focuses on modern bioenergy technologies, such as the use of biomass resources for electricity generation, for industrial applications and in the production of biofuels for transport.

Recent policy trends

There is a strong link between support policies and renewables deployment. Knowing the evolution of policies across regions and sectors is important in understanding the successes and failures that have been part of increasing renewables consumption. The *Renewables 2018* forecast for the electricity, heat and transport sectors examines this policy evolution and assesses its effectiveness for deployment over 2018-23. The forecast is updated annually to take recent policy changes and market developments for each sector into consideration.

Setting targets is a key first step for countries to deploy renewable energy sources in different sectors. Renewable energy targets can be sector-specific or apply to the overall energy mix, but they should be clear and ambitious (yet achievable), and should cover both medium- and long-term periods to demonstrate a government's ambition to increase the share of renewables in the energy mix. In 2010, 45 countries established a renewable energy target of some sort, mostly in Europe. By 2017, the number had almost quadrupled to 168, with the countries evenly spread across all regions, showing that the importance of renewable energy in decarbonising the energy mix has been widely recognised.

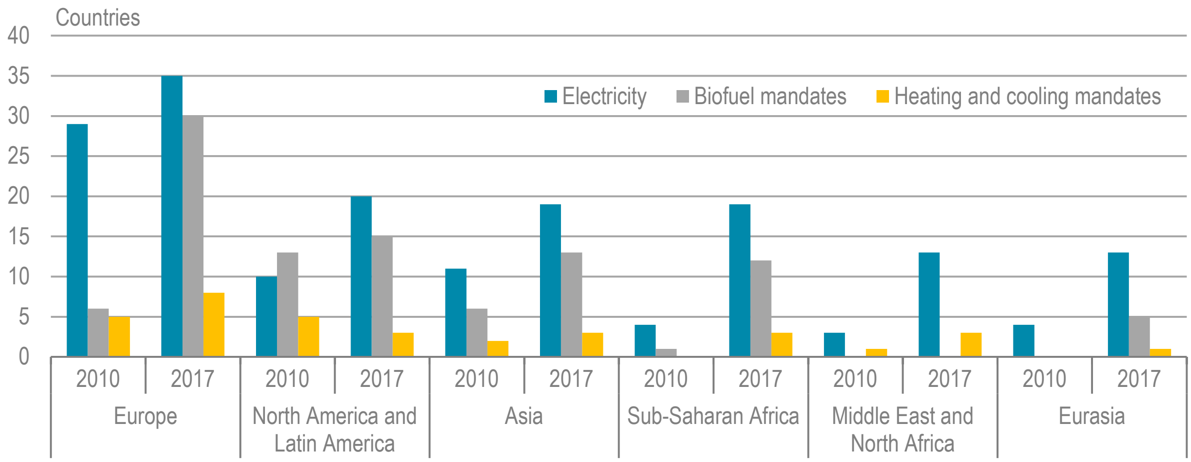
Policy mechanisms supporting renewables in the electricity sector have expanded significantly: in 2010, 61 countries had a feed-in tariff (FIT), green certificate or auction system in place, with Europe leading implementation. By 2017, policies for renewable power had spread to 121 countries, evenly distributed among Asia, Sub-Saharan Africa and the Americas. Nonetheless, Europe has continued to lead, with policy development stimulated by the mandatory EU 2020 targets (Figure 1.3).

Policy efforts subsequently translated to rising renewable electricity shares in many countries. In 2010, administratively set FITs dominated the renewable policy scene with implementation in 51 countries, while auction mechanisms were available in fewer than 20 countries. This trend has reversed, and in 2017 auction adoption in 88 countries surpassed FIT implementation in 81. Auctions have proven to be an effective price discovery mechanism for utility-scale renewable projects, but they are not always a suitable framework for nurturing small and medium-sized installations. An increasing number of countries is therefore adopting a mixture of policies to deploy renewable energy on a more tailor-made basis to accommodate various technologies, applications and purposes. In 2010, only 13 countries used auctions and FIT policies simultaneously, while in 2017 this number had increased to 51. In addition, other policy mechanisms such as tax discounts, grants and net-metering mechanisms are particularly suitable for commercial and residential renewable energy projects (see Chapter 5 for discussion of distributed applications).

The second sector after electricity in terms of number of countries with policies in place is transport. Renewables in the transport sector are supported mostly by various forms of biofuel mandates, greenhouse gas (GHG) reduction policies and fiscal benefits. In 2010, only approximately 30 countries had mandates in place, but by 2017 this number had tripled under the influence of policies to decarbonise transport, improve supply security and support strategic agricultural industries. Yet, most mandates require relatively low biofuel blending shares (e.g. <10% by volume or energy), with the exceptions of Brazil (27% ethanol) and Indonesia (20% biodiesel). The United States, Brazil and European countries introduced policy frameworks to mandate biofuel consumption, as well as governance measures to ensure they are adhered to. However, a number of countries still do not strongly enforce national biofuel blending targets and mandates. Reaching these mandates would result in a notable scale-up of biofuel production in many countries.

Opportunities for renewables in heating and cooling are vast, as this is the largest end-use sector, accounting for more than half of total worldwide final energy consumption. There are multiple barriers to renewables deployment, yet few countries have adopted mandatory targets or policies. In 2010, 13 countries, mostly in Europe and Latin America, had renewable heat mandates, but by 2017 they had spread to 22 countries across all regions, still led by Europe because of the EU 2020 renewable energy target. In addition, 30 more countries had other heat-related policy instruments such as grants and tax incentives in place.

Figure 1.3 Renewable energy policies by sector and region, 2010 and 2017



Notes: "Electricity" accounts for FITs, green certificate schemes and auctions. For transport, biofuel mandates are accounted for. For heating and cooling, relevant mandates are accounted for.

Sources: IEA/IRENA (2018), *Global Renewable Energy Policies and Measures Database*; IEA analysis.

This year's *Renewables 2018* forecast is overall more optimistic than last year's owing to recent policy changes and market developments in the countries and regions that influence the forecast the most (Table 1.1). Policy drivers and challenges for renewables deployment are outlined in the electricity, transport and heat chapters, complemented by additional analysis of technology trends in Chapter 5.

Table 1.1 Recent developments in renewables policies and markets included in the forecast

Sector	Region	Policy	Impact on forecast
Electricity	China	Renewable portfolio standards with green certificates and auctions for wind and PV	▲
		FIT phase-out and quota limits for utility and distributed PV	▼
		Biomass target raised from 15 gigawatts (GW) to 23 GW by 2020	▲
	USA	Corporate tax reduction and Base Erosion Anti-Abuse Tax	▼
		Import tariffs on solar PV modules, steel and aluminium	▼
		California regulation requiring solar PV on all new homes	▲
	Japan	2030 new energy plan	►
		Additional FIT approvals for solar PV, wind and biomass	▲
	India	Improved auction guidelines and clearer long-term tender plans	▲
		Risk of PV and wind auction delays, cancellations and undersubscription	▼
	EU	Increased EU-wide renewable energy target for 2030 (32%)	▲
		Additional renewable electricity auctions in several member states to meet 2020 targets	▲
		Increasing number of corporate power purchase agreements (PPAs) across member states	▲
	Latin America	Additional auctions and regulation allowing corporate PPAs in Argentina and Mexico	▲
		New auction design with stricter qualification requirements in Brazil	►
	MENA	Progress of numerous procurement schemes in the region	▲
		Delayed financial closure due to non-bankable PPA clauses, currency risks	▼
	SSA	Uptake and unlocking of national and Scaling Solar auctions across the region	▲
		Delayed grid connection and land acquisition problems; economic and political instabilities	▼
	ASEAN	New policy targets, regulations and incentives	▲
Transport	China	Ambition to roll out 10% ethanol blends nationwide by 2020	▲
	Brazil	RenovaBio programme signed into law and due to commence in 2020	▲
	India	New national biofuels policy enacted to widen range of feedstock	▲
	EU	Preliminary agreement for Renewable Energy Directive (RED) post-2020 with 14% transport target	▲
	Argentina	Anti-dumping duties lifted on biodiesel exports to EU but imposed for US	►
	UK	UK Renewable Transport Fuel Obligation long-term target to 2032	▲
Heat	China	100-counties biomass CHP pilot project, winter clean heat plan for Northern China	▲
	USA	Federal tax credit extension for ground-source heat pumps and biomass	▲
	India	National Biogas and Manure Management Programme target	►
	EU	1.3% annual increase of renewable heating and cooling share over 2020-30	▲

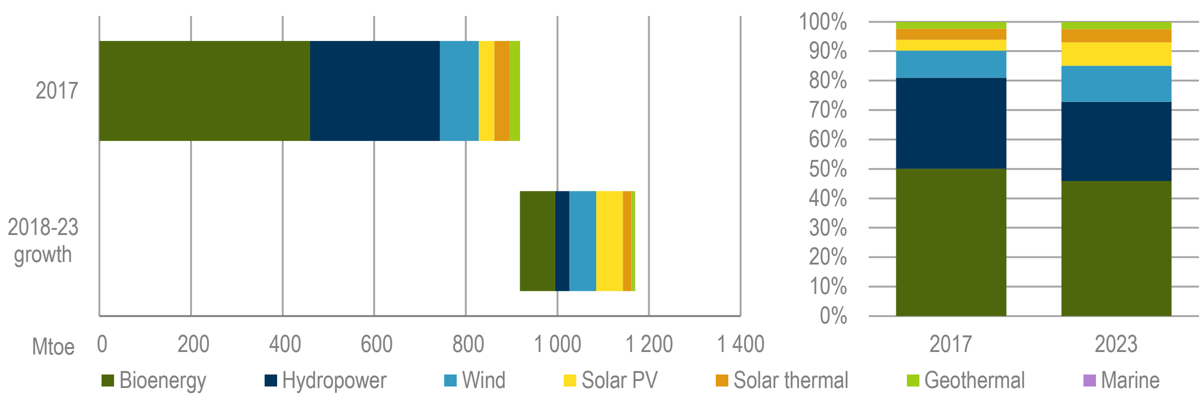
Notes: MENA = Middle East and North Africa; SSA = sub-Saharan Africa; ASEAN = Association of Southeast Asian Nations.

Global outlook

Robust growth in renewable energy is forecast over the next five years as consumption increases just 27% from 2018 to 2023. Driven by growing transport and heat demand, bioenergy leads the expansion. It is the largest source of renewable energy in 2023 owing to its considerable use as both a solid and liquid fuel in the electricity, transport and heat sectors (Figure 1.4). However, its share declines from 50% in 2017 to 46% as solar and wind expansion accelerates.

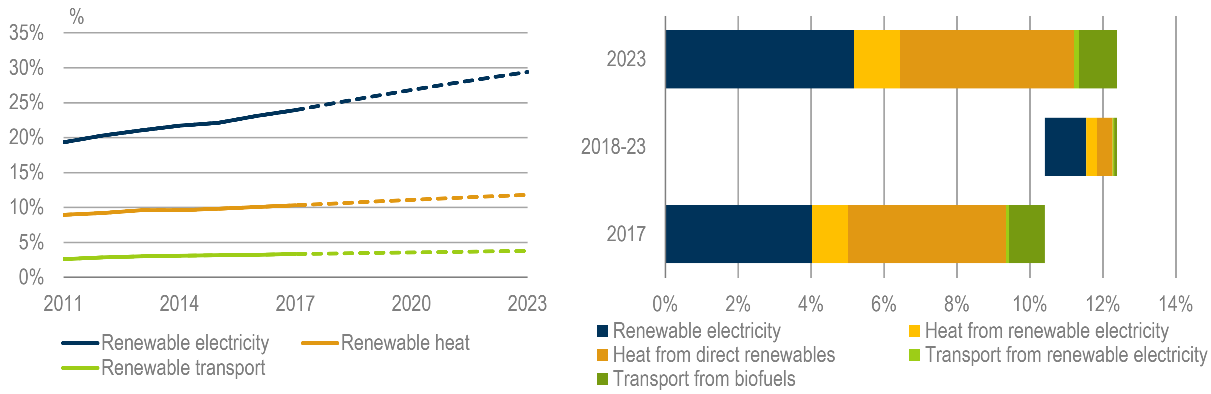
Wind and solar PV tied for the second-largest growth, followed by hydro, solar thermal and geothermal. In absolute terms, hydro continues to be the second-largest renewable energy source after bioenergy – most renewable electricity generation is still hydropower – followed by wind (both onshore and offshore) and solar PV. Solar PV generation expands the most quickly: its consumption doubles from 4% of overall renewable energy consumption in 2017 to almost 8% in 2023. Solar thermal is expected to grow 54% because it is increasingly used to generate heat in the buildings sector, while geothermal is forecast to expand 42% from district heating, direct use, and power generation.

Figure 1.4 Renewable energy consumption by technology, 2017-23



Consequently, the share of renewables in final energy consumption is forecast to grow from 10.4% in 2017 to 12.4% in 2023 – faster progress than in the previous six-year period. However, although the share of renewable energy sources increases in all three end-use sectors, the pace of progress varies significantly (Figure 1.5, left). The fastest expansion occurs within electricity as the renewables share increases from 24% in 2017 to 29% in 2023; electricity is also responsible for more than half of renewable energy growth over the forecast period, providing 1.1% of the 2% renewables share increase. Despite this progress in electricity, renewable heat makes up the largest portion of the overall share of renewables in 2023 (Figure 1.5, right). Only a modest increase in the share of renewable heat is foreseen, however, as robust growth in total heat demand is expected to result from continuous economic and population growth. The transport sector's share of renewables is anticipated to grow the most slowly, despite a 19% increase in renewable resource consumption over 2018-23. Growth is mostly from biofuels, with a small expansion in renewable electricity use in road and rail transport.

Figure 1.5 Share of modern renewable energy by end-use (left) and in total final energy consumption by end-use, 2017-23 (right)



Note: *Direct renewables* refers to the direct consumption of bioenergy, solar thermal and geothermal for heat-raising purposes.

China, the European Union, the United States, India and Brazil together are responsible for two thirds of global renewable energy consumption growth over 2018-23. Of these, Brazil remains the market with the highest share of renewables in 2023 because of significant bioenergy consumption in both the transport and industry sectors as well as the key role hydropower plays in meeting the country's power demand (Figure 1.6). China leads global growth over the forecast period and surpasses the European Union to become the largest consumer of renewable energy by 2023, driven by policies aimed at decarbonising all sectors to reduce harmful air pollution in major cities. China also demonstrates the second fastest progress, behind the European Union, with share growth of almost three percentage points owing to robust renewable electricity and heat expansion amid slower implementation of energy savings measures in the heat sector.

Policies to meet the European Union's 2020 and 2030 targets for renewable energy and energy efficiency result in the fastest progress over 2018-23 and a relatively high share of renewable energy in the region by 2023. Over the forecast period, country-level policies are expected to raise renewables-based consumption 18%, with most of the growth occurring in the electricity sector (led by wind), followed by heat and transport (in which bioenergy dominates). At the same time, total energy demand is expected to decline 3% as energy efficiency policies are successfully implemented. As a result, the share of renewables increases almost four percentage points, reaching 21% by 2023.

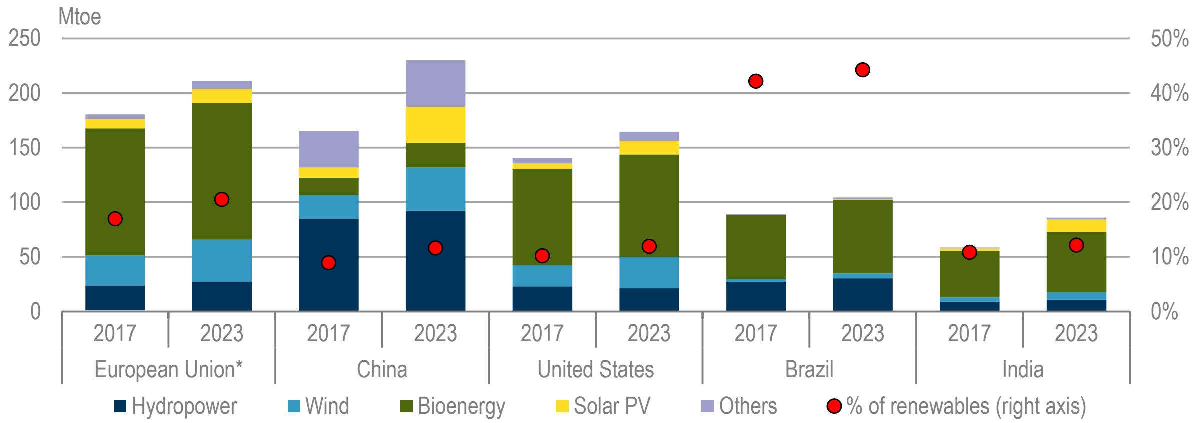
US renewable energy consumption is forecast to expand 17%, with wind and solar PV together accounting for two-thirds of this growth. However, slow growth of renewables use in the transport sector, the largest energy end-user in the United States, results in only a modest increase in the share of renewables. While fuel economy improvements are expected to reduce total transport energy consumption by 2023, the sector is still expected to account for 44% of US final energy demand – of which only 7% is met by renewable sources.

In India, bioenergy for heating and solar PV electricity together make up the majority of renewable energy expansion over the forecast period. Despite robust growth, the share of renewables is expected to increase only modestly due to minimal expansion of renewables in the heat sector, which remains the largest end user of energy.

Overall, the use of renewables needs to expand more quickly in all three sectors to be on track to meet long-term climate, cleaner air and access to modern energy goals, as demonstrated in the

International Energy Agency's (IEA) Sustainable Development Scenario (SDS). Should progress continue at the forecast pace, the share of renewables in final energy consumption would be around 18% by 2040, which is significantly lower than the SDS target of 28% (IEA, 2017).

Figure 1.6 Renewable energy consumption in major markets, 2017 and 2023



Notes: RE = renewable energy.
*The share of renewables in total final energy consumption is calculated using the methodology outlined in IBRD, World Bank and IEA (2015), *Global Tracking Framework (GTF) 2015*. The exact calculation and inclusion of specific energy flows may differ from that outlined in EU Directive 2009/28/EC.

Renewable heat

Renewable heat consumption is expected to increase 20% over the forecast period, reaching a share of 12% by 2023 (Figure 1.7, left). Overall heat demand grows only 6%, and renewables capture just over one-third of this growth. Within the buildings sector, the share of renewable energy increases from 10% to 12%, while in industry the share remains slightly lower, rising from 9% to 10%. Heat demand rises more quickly in the industry sector, but renewables growth is slightly lower than for buildings.

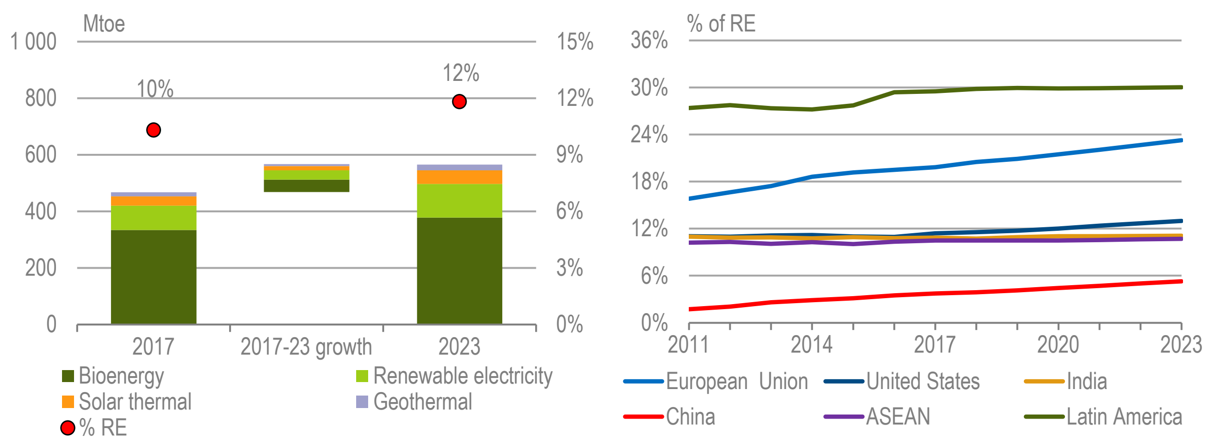
Bioenergy accounts for the largest share of growth (over 40%) and remains the largest source of renewable heat (Figure 1.7, left). However, renewable electricity used for heat begins to catch up with bioenergy in the buildings sector because of its quick growth, resulting from greater electrification of heat and the growing share of renewables in electricity generation. By 2023, the share of renewable electric heat expands to one-fifth of total renewable heat consumption, with 31% in the buildings sector. Solar thermal and geothermal energy also grow more quickly than bioenergy, but as this growth starts from a far lower base, their shares remain low at 8% (solar thermal) and 4% (geothermal).

Two-thirds of global renewable heat growth is expected to take place in China, the European Union, the United States and India, which are already the largest consumers of renewable heat. Growth of 54% in China means that the share of renewable heat increases from 4% to 6% over the forecast period. This is still low compared with many other countries, but considering the size of overall energy consumption, this increase makes China the largest consumer of renewable heat by 2023. Elsewhere in Asia, little change is expected in the renewable heat shares of India and the ASEAN countries.

The European Union's share of renewable heat consumption continues to increase at a steady pace to reach 23% in 2023, as most member states have policy instruments to support renewable heat expansion. The European Union is the only region in which overall heat demand is expected to decline thanks to significant energy efficiency improvements, thereby making it easier for the renewable heat share to increase.

Latin America remains the region using the highest share of renewable heat, but growth is below the global average at just over 10% over the forecast period. Within Latin America, Brazil is the largest consumer of renewable heat, but its share is expected to remain at 48% while both total heat and renewable heat consumption increase by around 10%.

Figure 1.7 Renewable heat consumption by technology (left) and shares in major countries/regions (right)



Note: *Renewable electricity* refers to the renewable portion of the electricity used for buildings and industry. For regional shares, energy consumed in blast furnaces is included.

Sources: IEA (2018), *World Energy Statistics and Balances 2018* (database), www.iea.org/statistics/; IEA (forthcoming), *World Energy Outlook 2018*.

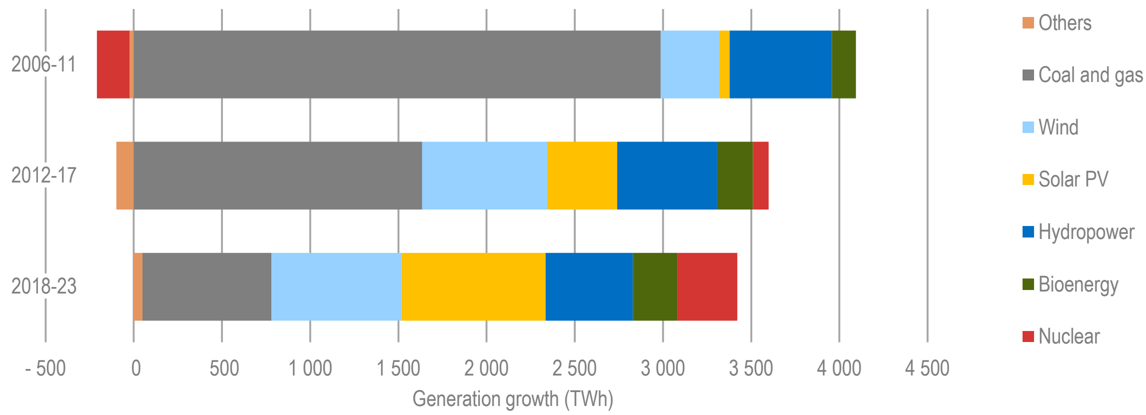
Renewable electricity

To meet growing consumption in the buildings, industry and transport sectors, global electricity generation is forecast to grow just over 2% annually over 2018-23. Overall renewable power generation is anticipated to expand 37% over the forecast period, with solar PV accounting for the largest growth among all sources, including fossil fuels, for the first time (Figure 1.8). Renewables are estimated to supply almost 70% of global electricity generation growth, and while the rapid expansion of renewables remains the key force behind this trend, the relatively slower growth of global electricity demand resulting from energy efficiency improvements and a shift in economic activity to less-energy-intensive industries, particularly in China, also contribute.

Compared with the previous six-year period, expansion in coal- and natural gas-fired generation is expected to decline considerably. Globally, generation from natural gas power plants is squeezed between low-cost coal and rapidly expanding solar PV and wind technologies. However, coal generation growth is forecast to come mostly from emerging economies in the ASEAN region, India and China. In fact, despite significant growth in renewables-based generation, in absolute terms it is forecast to be lower than coal, which remains the largest source of global power output.

The share of renewables in global electricity output is expected to increase five percentage points over the forecast period, from 25% in 2017 to 30% in 2023 (Figure 1.9, left). Hydropower is forecast to expand 12% over the forecast period – slower than its growth over 2012-17, but it remains the largest renewable electricity generation source in absolute terms by 2023. Wind generation is forecast to increase two-thirds over the forecast period, with its share in global electricity generation growing from 4% in 2017 to almost 7% in 2023. Power output from solar PV triples over 2018-23, overtaking bioenergy to become the third-largest source of renewable electricity by 2023, followed by wind. With this rapid growth, the share of solar PV in global electricity generation doubles to over 4% at the end of the forecast period.

Figure 1.8 Electricity generation growth by fuel, 2006-23



Note: TWh = terawatt hour.

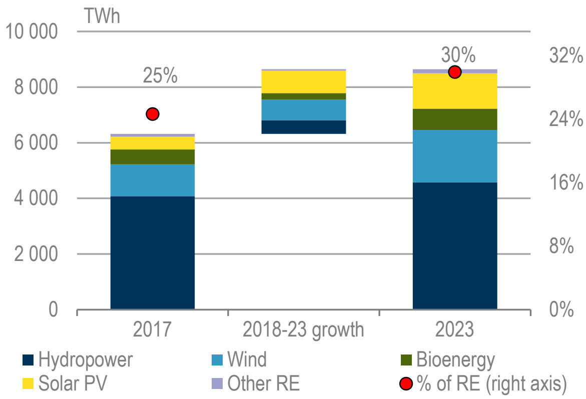
Shares of renewable electricity generation vary significantly by country and region, but progress over the forecast period is notable in many countries (Figure 1.9, right). Today renewables account for over 95% of electricity generation in countries where abundant hydropower resources have already been exploited, such as in Norway, Paraguay, Uruguay, Ethiopia, Costa Rica and Nepal.

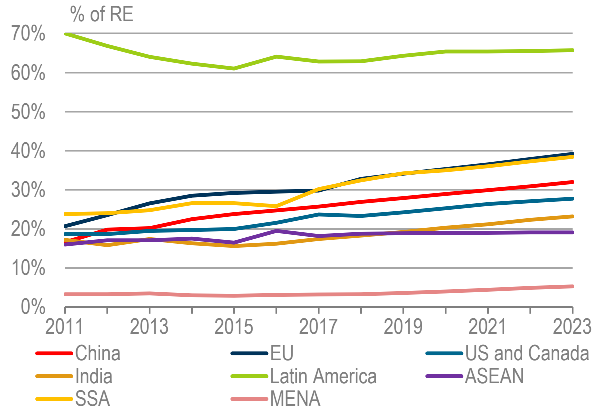
Latin America has the highest share of renewables of all the regions considered in *Renewables 2018*, as hydropower accounts for over half of power generation in many countries in the region. In the European Union, the renewables share is expected to grow ten percentage points to reach almost 40% in 2023, mostly from wind and solar PV expansion, and the share of variable renewables is expected to be 20% by the end of forecast period. Growth of the renewables share in Sub-Saharan Africa follows a trajectory similar to that of the European Union, but hydropower remains the dominant source at 80% of total renewable generation.

In China, electricity generation from renewables increases 46% over 2018-23, led by wind and solar PV technologies. With this growth, renewables account for over half of total electricity generation expansion over the forecast period; the share of renewables is anticipated to increase from 26% in 2017 to 32% in 2023. In North America (excluding Mexico), growth in the share of renewables over the forecast period is driven by rapid wind and solar expansion in the United States. By 2023, hydropower in Canada, which represents 30% of renewable electricity in North America, contributes the most to the renewables share.

Despite rapid electricity demand growth, the use of renewables in India's power mix, mostly solar PV, accelerates over the forecast period. In ASEAN countries, the share of renewables is expected to progress slowly and remain below 20%, with hydropower plants dominating renewable generation. MENA has one of the lowest shares among all *Renewables 2018* regions due to the dominant use of natural gas in electricity generation, resulting from abundant resource availability and limited hydropower development.

Figure 1.9 Global renewable electricity generation by technology (left) and shares in selected markets (right)



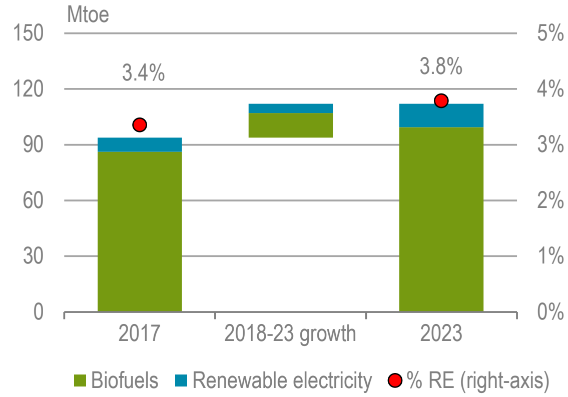


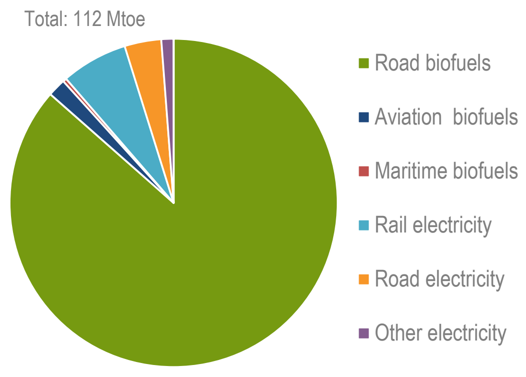
Note: Share of renewables in electricity generation in this graph refers to gross electricity generation and not final consumption.

Renewable energy in transport

Renewable energy in transport is anticipated to grow 19% over 2018-23, but the increase in the renewable share of transport demand is minor, from 3.4% in 2017 to just 3.8% in 2023 (Figure 1.10, left). As such, transport has the lowest penetration of renewables of all three sectors. Renewables account for 11% of transport fuel demand growth, while fossil fuel demand increases 5% over the forecast period.

Figure 1.10 Renewable energy in transport by fuel (left) and renewable consumption by transport mode in 2023 (right)





Notes: consumption in pipeline transport and unspecified uses. 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.

Biofuels accounted for 92% of renewable energy in transport in 2017, and this share is anticipated to decrease only slightly to 89% by 2023. The dominant share of biofuels is facilitated by their compatibility with existing internal combustion engine (ICE) vehicles and fuelling infrastructure at low blending levels. For the portion of biofuels to increase within transport's renewable energy share and offset more petroleum product demand, greater consumption of unblended biofuels or higher biofuel blend shares will be required. Of these options, higher-rate biofuel blending is more challenging because it would require expansion of the fleet of suitable vehicles and changes in fuelling infrastructure.

Currently, biofuels are used principally within road transport, with passenger cars accounting for most consumption. The use of biofuels in aviation is at an incipient stage, and it is even less advanced in maritime transport. Given that electrification is difficult, higher sustainable biofuel consumption in aviation and maritime transport is an attractive option to decarbonise these two end-use sectors.

Renewable electricity in transport is anticipated to grow 65% over 2018-23 (Table 1.2). Rail accounted for 66% of transport sector renewable electricity consumption in 2017, but more robust growth of electric vehicles (EVs) in road transport means that by 2023 rail's share is anticipated to fall to 58%. Increasing renewable energy consumption by EVs requires a shift in the vehicle fleet, rollout of charging infrastructure and a rising share of renewable sources in electricity generation; the portion of electricity in the transport sector's renewable energy contribution in 2023 therefore remains far lower than that of biofuels (Figure 1.10, right).

Table 1.2 Estimated renewable electricity consumption in road and rail transport

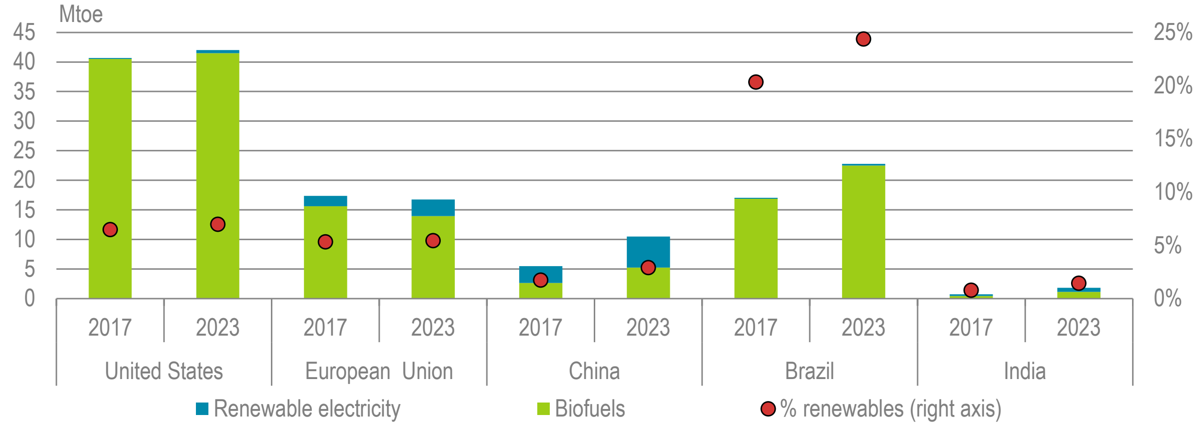
	Renewable electricity consumption 2017 (Mtoe)	Renewable electricity share 2017 (%)	Renewable electricity consumption 2023 (Mtoe)	Renewable electricity share 2018 (%)	Consumption growth 2018-23 (%)
Rail	5.2	24	7.4	29	42
Road	1.2	27	4.1	33	228
Total	6.5	24	11.5	30	77

Note: Renewable electricity consumption in pipeline transport and unspecified uses is not shown.

Source: IEA (2018), Modelling of the Transport Sector in the Mobility Model (MoMo), May 2018 version.

The **United States** has the largest contribution of renewables in transport (Figure 1.11), primarily because it is the global leader in biofuel production and has high per-capita fuel consumption. The Renewables Fuel Standard, which establishes annual volumes of renewable fuel consumption to 2022, is the key policy instrument driving biofuel demand. Currently, the average blend level of ethanol in gasoline is around 10%, with a lower share of biofuels in diesel vehicles. Consequently, the US renewables share was 6.5% in 2017, but only a minimal increase is expected by 2023 due to the challenges of making higher-ethanol blends (e.g. 15%, or up to 85% ethanol) more available at the pump, and of expanding the number of vehicles with higher biofuel compatibility. The growing penetration of road EVs means renewable electricity in transport almost triples by 2023, although its energy contribution remains minimal compared with biofuels.

Figure 1.11 Renewable energy in transport and share of total transport demand in selected countries and regions



In the **European Union** the majority of renewable energy in transport is also from biofuels, primarily crop-based conventional biofuels, for which consumption has grown in response to the RED target of 10% renewables in transport by 2020. Overall, the share of renewables in EU transport remains steady at just over 5% over the forecast period.[5] By 2023, renewable energy in transport decreases in absolute terms due to the anticipated contraction in biofuel consumption as a result of weaker policy support for conventional biofuels after 2020, alongside lower transport fuel demand due to increased vehicle fleet fuel efficiency.

Policy support for non-crop-based advanced biofuels is increasing, and their production is anticipated to grow over the forecast period. In absolute terms, however, advanced biofuel consumption remains low in 2023 compared with conventional biofuels. Renewable electricity makes a notable contribution, accounting for 10% of renewable transport in 2017 – of which 95% is from rail. Meanwhile, by 2023 electricity's share of all renewables in EU transport grows to 17% owing to contraction in biofuels consumption, growing deployment of EVs in road transport, and a greater share of renewables in electricity generation (39% in 2023).

China differs from the other countries discussed in that around half of renewable energy in transport came from electricity in 2017. EV uptake is driven by robust policy support and the pressing need to increase air quality in cities. China possesses the world's largest electric car fleet, although two- and three-wheeled vehicles account for more electricity consumption. Renewable electricity in transport is further sustained by the increasing use of renewable resources in electricity generation (32% by 2023).[6] In 2023 biofuels make a roughly equal contribution to renewable energy in transport, mainly as a result of higher ethanol consumption from the 10% blending mandate being extended nationwide in 2020. Consequently, the share of renewable energy in transport almost doubles from 1.7% in 2017 to 3% in 2023, despite a 14% increase in fossil transport fuel demand.

Brazil's use of biofuels, particularly sugar cane ethanol, facilitates a high level of renewable energy consumption in transport, second only to the United States. Significant ethanol consumption is

[5] The share calculated under the RED policy framework will be higher, however, as a result of multiplication of renewable energy from sources such as advanced biofuels and electricity in road transport.

[6] However, despite more renewables contributing to electricity generation, the predominance of coal-based electricity generation in China means that CO_2 emissions per kilometre (/km) for electric vehicles remains high.

supported by the country's extensive flexible-fuel vehicle fleet. This allows for direct competition between unblended fuel ethanol and gasoline (blended with 27% ethanol) at the pump. This, in addition to mandated biodiesel demand, helped Brazil realise a global-high 20% share of renewables in transport in 2017. The energy contribution from biofuels is anticipated to increase further still, as the RenovaBio policy boosts biofuel output after its introduction in 2020, and consequently raises the renewable energy share to 24% in 2023.

In **India** renewable energy supplied less than 1% of transport fuel demand in 2017, with broadly similar contributions in energy terms from electric rail and biofuels. The energy contribution of biofuels is expected to grow more over 2018-23, principally owing to the country's blending programme to meet a mandate of 5% ethanol in gasoline. Transport sector renewable electricity consumption also more than doubles by 2023, with growth from both rail and road EVs. However, due to growing demand for fossil fuels, India's renewable energy share in transport remains below 1.5% at the end of the forecast period.

Box 1.3 Sustainability is critically important for bioenergy deployment

Sustainable bioenergy is fundamental to decarbonisation of the energy system. Modern bioenergy accounts for the largest amount of renewable energy within the *Renewables 2018* forecast period and beyond. It also plays an essential role in the IEA long-term climate scenarios, making key contributions in several sectors that are difficult to decarbonise by other means (e.g. aviation). Furthermore, in addition to reducing CO_2 emissions, other benefits of best-practice use of bioenergy include job creation, rural development and enhanced waste management.

The IEA is fully aware of the debate regarding the sustainability of certain forms of bioenergy. Particular concerns relate to air pollutant emissions from residential biomass heating[7], lifecycle emissions and land use change associated with some conventional biofuels, and deforestation. Unsustainable bioenergy deployment has justified these concerns in some cases; consequently undermining confidence in bioenergy, including those applications which are sustainable. However, in other cases analysis indicates that negative perceptions of bioenergy are not based on a scientific grounding. In addition, perceptions of modern bioenergy also suffer from being confused with the traditional use of biomass, as defined in Box 1.2, which is entirely different.

This highlights that because bioenergy sustainability is complex and has multiple aspects, each application must be judged on its own specific circumstances, and generalisations regarding the sustainability of bioenergy feedstocks, fuels and technologies have limited value and can be misleading.

For bioenergy applications to be used to greatest effect in decarbonising the electricity, heat and transport sectors, they must be employed in a best-practice manner, providing net lifecycle GHG emissions reductions while avoiding unacceptable social, environmental or economic impacts. Bioenergy is not unique in this regard, as sustainability challenges associated with scaling up deployment of fossil-based and other renewable energy technologies must also be managed.

Policy makers must ensure suitable frameworks are established to deliver sustainable bioenergy. The first step to ensuring best-practice is to understand the criteria used to assess sustainability. The Global Bioenergy Partnership (GBEP), an intergovernmental initiative that brings together 50 national governments, the IEA and other international organisations, has produced a set of sustainability indicators for bioenergy organised under overarching environmental, social and economic pillars.[8] The

[7] Air pollutant emissions from household use of solid biomass-based heating is discussed in depth in Chapter 5.

[8] www.globalbioenergy.org/fileadmin/templates/gbep/images/Ylenia/Summary_table_website_12-11.pdf.

GBEP criteria are recognised among stakeholders as representing the key issues that need to be managed to ensure the best-practice employment of bioenergy applications, and they can form the basis of policies and regulations to support sustainable deployment.

There are already examples of established frameworks to ensure sustainability, such as:

- The EU sustainability criteria for biofuels and bioliquids, which demand minimum lifecycle GHG emission reduction and stipulate the types of land on which crop feedstocks for biofuel production cannot be grown. In 2016 98.7% (by energy) of reported biofuel consumption was compliant.
- Policies that facilitate demand for biofuels with the lowest lifecycle GHG or CO_2 emissions such as California's Low Carbon Fuel Standard, which takes into account emissions from land use change, and Brazil's forthcoming RenovaBio program.
- Brazil's forest code which requires a legal reserve for natural habitat, and green protocol to eliminate in-field burning of sugarcane residues in São Paolo state.
- The Roundtable on Sustainable Biomaterials (RSB), which outlines principals and criteria on how to produce biomass, biofuels and biomaterials in an environmentally, socially and economically responsible way, as well as certification to demonstrate sustainable performance.

Robust governance is required to ensure that such policies and regulations are adhered to. When suitable monitoring and control mechanisms are in place, policy makers can establish policy support for bioenergy in the confidence that it will deliver beneficial outcomes. These mechanisms include third-party certification of biomass fuel supply chains to ensure they are sustainable, and comprehensive assessments of lifecycle CO_2 emissions for different biomass fuel production pathways.

In keeping with the bioenergy focus of *Renewables 2018,* the potential to scale up several bioenergy applications has been assessed.[9] These applications highlight the potential to use untapped waste and residue biomass resources that generally offer low lifecycle GHG emissions and mitigate land use change concerns, and they can also deliver waste management and air quality benefits.

As the primary purpose of *Renewables 2018* is to reflect renewable energy market developments, complex and specific sustainability considerations relevant to the use of different biomass fuels and feedstocks are not discussed. However, bioenergy sustainability is covered in detail in the IEA's 2017 *Technology Roadmap: Delivering Sustainable Energy*, available free of charge from the IEA webstore. In addition, the IEA technology collaboration programme for bioenergy conducts research dedicated to sustainable biomass markets.[10]

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[9] Including aviation biofuels from waste oil and animal fat feedstocks; biomass and waste in cement production; and the use of in-field sugar cane residues for co-generation in the sugar and ethanol industry.

[10] For further information please consult www.ieabioenergy.com.

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2. RENEWABLE ELECTRICITY

Highlights

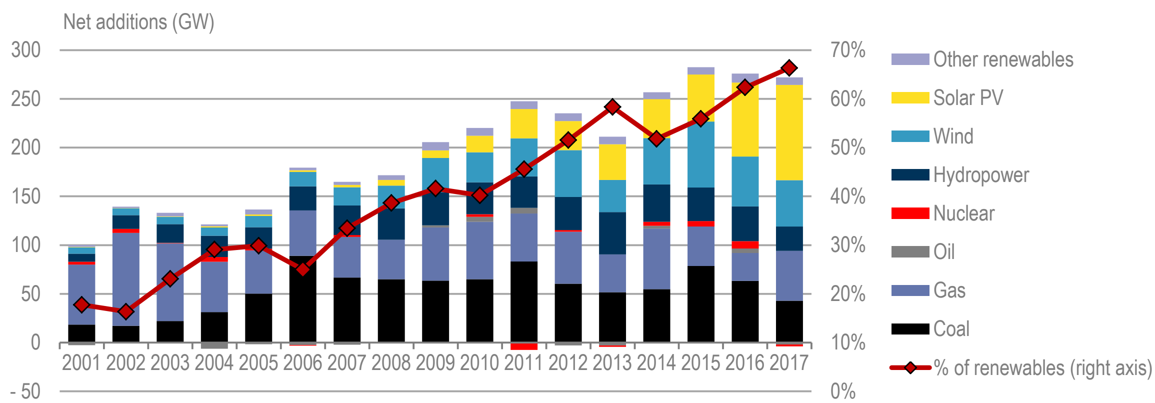
- Net renewable capacity additions of 178 gigawatts (GW) in 2017 – 4% higher than in 2016 – set another world record. For the first time, renewable technologies accounted for more than two-thirds of global net electricity capacity growth. Solar photovoltaic (PV) capacity expanded the most quickly at 97 GW of additions, over half of which were in the People's Republic of China.[1] Onshore wind expansion slowed for the second year in a row (by 10%), for capacity additions of 44 GW, and hydropower growth also decelerated 30% to 25 GW, both due to slowdown in China. Bioenergy capacity expanded 7.2 GW, geothermal 0.6 GW, and concentrated solar power (CSP) 0.1 GW.
- In the main case forecast for 2018-23, renewable capacity grows by over 1 terawatt (TW), or 46%. Solar PV accounts for more than half, owing to policy and market improvements; although additions in 2018 are expected to be less than in 2017 due to China's recent policy changes, they recover after 2020 as solar becomes increasingly competitive. The wind forecast remains stable from last year, with capacity expanding 63% (324 GW), 11% of which is offshore. Growth prospects for hydropower (125 GW) and bioenergy (37 GW) are both more optimistic than last year, mostly owing to developments in China.
- China, responsible for 41% (438 GW) of global expansion, shows the largest growth for all renewable resources except geothermal and marine. Despite uncertainties in the policy transition towards more sustainable support schemes and grid integration, China is expected to comfortably exceed newly introduced renewable portfolio standard (RPS) targets by 2020, with renewables becoming more competitive with traditional fuels.
- The European Union demonstrates the second-largest growth market, with 124 GW of renewables becoming operational in 2018-23 as the ambitious 32% renewable energy target for 2030 is approved, key countries introduce additional auctions, and the growing corporate power purchase agreement (PPA) market takes advantage of lower wind and solar costs. While renewable capacity is forecast to grow 44% in the United States, the forecast has been revised down from last year. Despite strong state-level policy support and increasing competitiveness of renewables, recent changes to the federal tax code, trade policies and energy plans have created forecast uncertainties.
- India's renewable capacity doubles over 2018-23, mainly from solar PV and onshore wind. As in last year's forecast, grid integration and the financial health of distribution companies hamper faster growth. Latin America's forecast is more optimistic, with macroeconomic improvements in Brazil and successful auctions in Argentina. Additional wind and solar auctions throughout sub-Saharan Africa (SSA) drive a more optimistic forecast, but the pace of implementation depends on the availability of affordable financing and timely grid expansion.
- Renewable capacity growth in 2018-23 could reach over 1.3 TW in the accelerated case, 25% higher than in the main case. This additional growth depends on governments introducing measures to tackle policy uncertainty as well as grid integration and financing challenges. China, India, the European Union and the United States together account for almost two-thirds of additional capacity growth in the accelerated case.

[1] Hereafter "China".

Recent deployment trends

In 2017, renewable capacity expansion demonstrated growth of over 8% year-on-year (y-o-y) to reach 178 GW, breaking the record once again. At over two-thirds of global net capacity additions, renewable technologies surpassed both fossil fuel and nuclear capacity combined (Figure 2.1). Solar PV continued to show the largest global net capacity growth, with 97 GW becoming operational (higher than net growth from natural gas and coal combined). This record solar PV expansion was a 30% increase from 2016 and compensated for lower annual growth of wind (48 GW), hydropower (25 GW) and other renewables (8 GW) combined. USD 298 billion was invested in new renewable capacity in 2017, 7% less than in 2016 owing to declining average investment costs for solar PV plants (IEA, 2018b).

Figure 2.1 Annual net electricity capacity additions by source, 2001-17



Sources: Fossil fuel capacity calculations based on Platts (2018), *World Electric Power Plants Database* (database); historical renewable capacity data for OECD countries based on IEA (2017), *Renewables Information 2017*, www.iea.org/statistics/.

In 2017, China alone commissioned 55% of global solar PV additions, with a record 53 GW becoming operational owing to feed-in tariffs (FITs). Despite a 30% decline in annual growth, the United States retained the second-largest PV market, as developers rushed to commission projects before the expiration of federal tax credits in December 2015 (Table 2.1). For the first time, India's market was the third-largest, with annual additions more than doubled as a result of federal and state-level auctions. Japan's annual solar PV growth declined for the second year in row (by 11%, to 7 GW) due to stricter FIT regulations from the previous year. Turkey's PV capacity additions more than quadrupled in 2017, driven by the developer rush to commission projects before regulation changes raise grid connection and licensing costs. In addition, Germany, Australia, Korea and Brazil each installed more than 1 GW of solar PV capacity in 2017.

Annual onshore wind expansion lost speed for the second year in a row, down 10% for an addition of 43.7 GW in 2017, with lower capacity growth in both China and the United States, which nevertheless remained the top two markets. In China, the installation ban in the North China provinces to combat high curtailment was the main reason for slower deployment, while annual capacity expansion accelerated in Germany and India because of expiring policy support. Hydropower additions declined in 2017, as large hydropower growth continued to decelerate in major markets such as China and Brazil. Global hydropower additions fell by almost one-third to 25 GW, of which 2.7 GW was from pumped storage projects. However, India, Angola and the Russian Federation[2] commissioned large hydropower projects last year, placing them among the top five growth markets.

In 2017, bioenergy capacity grew 7.2 GW, 17% less than in 2016. Higher deployment in China and Japan (driven by FITs) was offset by slowdowns in India, the United Kingdom and Brazil. In 2017, record-level offshore wind capacity was connected to the grid (3.8 GW), mostly in the United Kingdom and Germany, and followed by China. With the commissioning of two large-scale plants in Indonesia and continuous expansion in Turkey, global geothermal additions more than doubled last year, with smaller additions from Chile, Iceland and Honduras. South Africa's Xina Solar One project and China's small demonstration plant together accounted for global CSP capacity growth in 2017.

Table 2.1 Top five countries for renewable capacity additions by technology, 2017

Solar PV	GW	Onshore wind	GW	Hydro	GW	Bioenergy	GW
China	53.1	China	14.5	China	11.5	China	2.7
USA	10.6	USA	7	Brazil	3.4	Netherlands	0.7
India	9.6	Germany	4.9	India	1.8	Japan	0.5
Japan	7.0	India	4.1	Angola	1.1	Thailand	0.4
Turkey	2.6	Brazil	2.2	Russia	0.9	Brazil	0.4
Offshore wind	**MW**	**Geothermal**	**MW**	**CSP**	**MW**	**Marine**	**MW**
UK	1 753	Indonesia	275	South Africa	100	UK	5
Germany	1 247	Turkey	243	China	20	China	2
China	540	Chile	55			Canada	1
Belgium	165	Iceland	45			Australia	1
Finland	60	Honduras	35			Netherlands	1

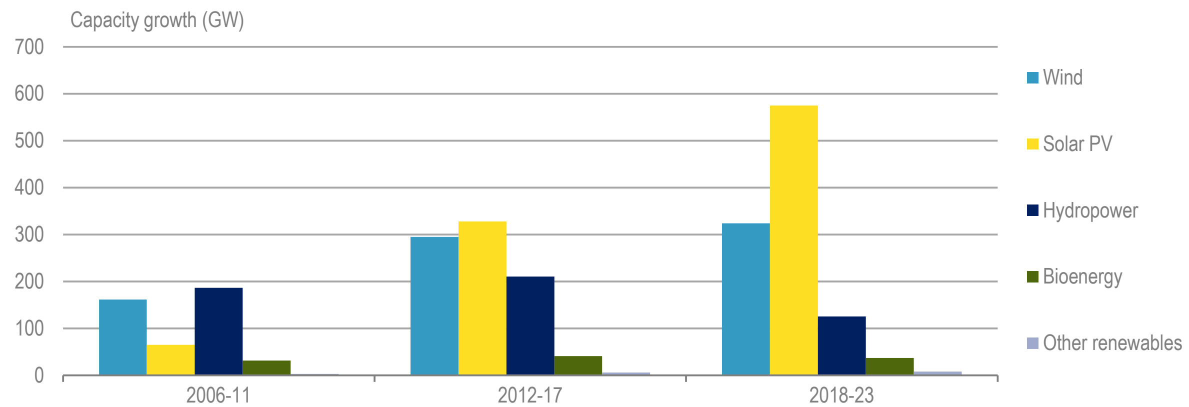
Note: MW = megawatt.

Main case technology forecast summary

In the main case, renewable electricity capacity is forecast to grow 46% (more than 1 TW) during 2018-23, and renewables account for over 70% of global net cumulative electricity capacity additions from all sources. Solar PV capacity growth over 2018-23 is three-quarters greater than it was over the 2012-17 period, while wind and bioenergy expansion remain stable and hydropower additions slow by 40% (Figure 2.2).

[2] Hereafter "Russia".

Figure 2.2 Historical and main case net renewable capacity additions by technology, 2006-23



Source: Historical capacity data for OECD countries based on IEA (2017), *Renewables Information 2017*, www.iea.org/statistics/.

Solar PV dominates renewable capacity growth in the next six years, with 575 GW expected to become operational. Utility-scale projects represent 55% of this growth, while distributed generation capacity growth accelerates (see sections in Chapter 5 for details on distributed generation). China alone accounts for almost 45% of global solar PV expansion (Table 2.2). Thus, the size of the global PV market over the forecast period is highly dependent on policies and market developments in China, where the government has phased out FITs and introduced deployment quotas. As a result, China's solar PV deployment is expected to be slower than in 2017 (53 GW) in the short term, reducing global demand. Consequently, the global module supply glut is anticipated to result in lower module prices. With increasing cost-competitiveness and continuous policy support, demand recovery is expected after 2020, with global additions of over 110 GW by 2023 in the main case – led by China, the United States, India and Japan, with growth in Latin America and Africa accelerating because of improving economic attractiveness and continued policy support.

Table 2.2 Top five countries for renewable capacity growth by technology, 2018-23

Solar PV	GW	Onshore wind	GW	Hydro	GW	Bioenergy	GW
China	255.8	China	109.0	China	47.3	China	13.7
USA	70.0	USA	43.0	India	9.3	Japan	2.6
India	62.9	India	32.5	Brazil	8.3	UK	2.1
Japan	21.2	Germany	16.7	Ethiopia	5.1	India	2.1
Mexico	15.8	Brazil	6.4	Turkey	3.2	Brazil	1.7
Offshore wind	**GW**	**Geothermal**	**MW**	**CSP**	**MW**	**Marine**	**MW**
China	10.5	Indonesia	1 200	China	1 900	UK	26
UK	6.7	Kenya	520	Morocco	730	France	22
Netherlands	3.2	Philippines	372	UAE	700	Korea	13
Germany	2.4	Turkey	300	South Africa	300	Indonesia	12
Denmark	1.7	New Zealand	168	Israel	230	China	8

Wind capacity is forecast to grow almost 324 GW to reach 839 GW by 2023; offshore wind accounts for 11%. In 2020, cumulative solar PV capacity surpasses that of wind as annual onshore wind growth remains within 45 GW to 52 GW in the main case forecast. The phase-out schedule of federal tax incentives in the United States, the expiration of FITs and grid integration challenges in China, and the timetable of auctions in Europe, India and other regions make the trend for annual additions volatile. **Offshore wind** capacity is expected to almost triple to nearly 52 GW in 2023, with half the growth driven by the European Union and the other half by China and other Asian countries.

Hydropower capacity is expected to increase 125 GW – 40% less than in 2012-17 due mainly to less large-project development in China and Brazil, where concerns over social and environmental impacts have restricted project pipelines. Meanwhile, deployment in India, Africa, and Southeast Asia accelerates in response to new demand, untapped resource potential, and attractive economics to improve electricity access affordably. One-fifth of overall growth (26 GW) is from pumped-storage hydropower projects that help integrate variable renewables.

Bioenergy is anticipated to grow 37 GW by 2023, 10% lower than deployment over 2012-17. Global additions remain relatively stable at between 5 GW and 8 GW throughout the forecast period. The forecast has been revised up from last year to reflect a more optimistic outlook for China, where a new policy initiative is expected to drive robust co-generation and energy-from-waste (EfW) deployment. China therefore accounts for 37% of bioenergy deployment, but markets in Asia-Pacific and Brazil also make key contributions based on diverse policy support mechanisms. The forecast for bioenergy in the European Union has been revised down, although the United Kingdom and the Netherlands remain major markets. While bioenergy is not expanding rapidly into many new markets, Mexico and Turkey do show signs of growing deployment.

CSP is expected to grow 87% (4.3 GW) over the forecast period, 32% more than in 2012-17. China leads at 1.9 GW, followed by 1 GW from projects receiving multilateral development bank support in Morocco and South Africa, 1 GW in the Middle East and 300 MW in Australia and Chile. Spain and the United States, the two countries with the most installed capacity, are not expected to commission projects over the forecast period, so China is expected to overtake the United States to have the second-largest CSP installed base by 2023. Recent auction results indicate significant cost reduction potential, but technology risk, restricted access to financing, long project lead-times and market designs that do not value storage continue to challenge CSP deployment.

Geothermal capacity is set to grow 28% (4 GW) to reach just over 17 GW by 2023 as projects in nearly 30 countries come online, with 70% of the growth in developing countries and emerging economies. The Asia-Pacific region (excluding China) has the largest growth (1.9 GW) over the forecast period. Indonesia's expansion is the strongest, propelled by abundant geothermal resource availability and a strong project pipeline in the construction phase supported by government policies. Kenya, the Philippines and Turkey follow, responsible for 32% of additions. Although pre-development risks are still an important barrier to securing financing for geothermal projects, exploration and construction of facilities in Latin American and Caribbean countries is expected to take off because geothermal technology generates stable, carbon dioxide (CO_2) emissions-free baseload power.

Marine technologies continue to account for the smallest portion of renewables growth, as expansion typically comes from small-scale demonstration and pilot projects of less than 1 MW. However, larger projects (6 MW to 15 MW) emerging in United Kingdom and France are boosting capacity growth. Globally, tidal technology is expected to account for 50% of all marine-based additions, followed by wave projects.

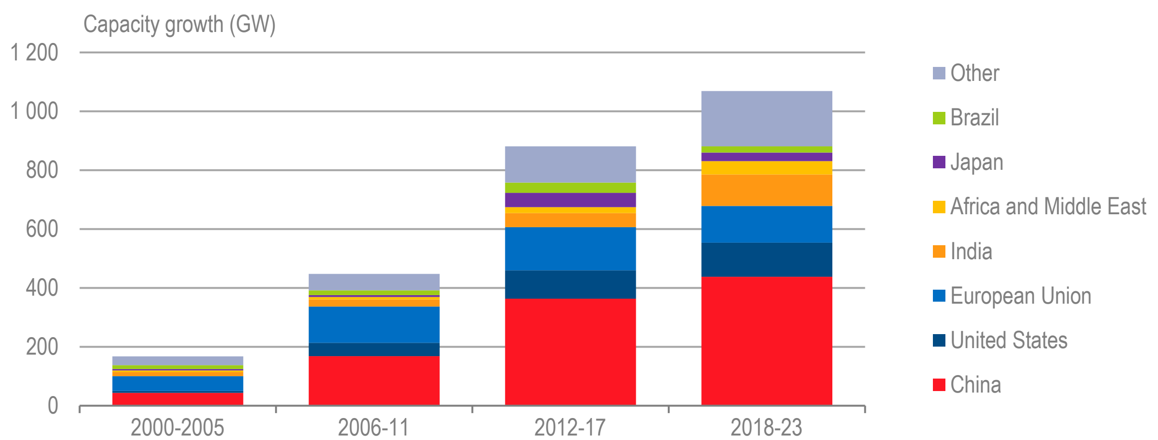
Main case regional forecast summary

In the main case, renewable capacity grows 46%, from 2 320 GW in 2017 to over 3 390 GW in 2023, accounting for over two-thirds of all power plants installed globally. This growth is driven by strong policy support in many countries and continuously falling costs that make solar and wind technologies more competitive with other modes of energy production.

China continues to have the fastest-growing renewables market over the forecast period, with capacity expanding by 438 GW in response to continued policy support and increasing air pollution concerns (Figure 2.3). Expansion is more optimistic than in last year's forecast owing to faster-than-expected solar PV growth in 2017 – despite recent policy changes that introduced caps on distributed generation and phased out FITs. This forecast therefore anticipates that China will comfortably meet the renewable generation targets introduced in the new provincial RPSs. New policies are also expected to address grid integration challenges by promoting capacity expansion in provinces close to demand centres. In addition, China is replacing FITs with auction schemes for solar PV and onshore wind to make these technologies more cost-competitive and reduce the subsidy burden that continues to impair renewables expansion.

The **European Union** is expected to have the second-largest growth market in this forecast period, surpassing both the United States and India as it commissions 124 GW of additional renewable capacity, 92% of it wind and solar. Several factors encourage this optimistic outlook: approval of a more ambitious 32% renewable energy target at the EU level; introduction of additional auctions in France, Italy, Germany and Spain; increased distributed solar PV deployment; and an enlarged corporate PPA market that takes advantage of wind and solar technology cost reductions.

Figure 2.3 Renewable capacity growth by country/region, 2000-23



Source: Historical capacity data for OECD countries based on IEA (2017), *Renewables Information 2017*, www.iea.org/statistics/.

In the **United States**, renewable capacity grows 116 GW over 2018-23. The forecast has been revised down slightly from last year due to recent tax reforms and trade policy changes. The corporate tax reduction, import tariffs on solar PV modules and cancellation of the Clean Power Plan (CPP) are anticipated to pose economic challenges for new wind and solar projects. However, state-level RPSs and technology-specific incentives, especially for distributed solar PV, remain strong drivers. In addition, corporate renewable energy procurement is anticipated to grow over the forecast period as onshore wind and solar PV technologies are expected to become more cost-competitive.

India leads renewables expansion in the Asia-Pacific region (excluding China), with 107 GW expected to become operational over the forecast period. Solar PV and wind provide 89% of India's renewable growth, propelled by national and state-level auctions. However, grid integration and the financial health of distribution companies continue to impede deployment, despite improvements in the past year. Forecasts for **Japan** and **Korea** are more optimistic than last year. In Japan, announced solar PV project cancellations under the FIT scheme fell below last year's estimates, and the government continues to approve new commercial and residential projects. Still, future project cancellations and grid integration remain key forecast uncertainties. For Korea, the new government's ambitious energy plan is reflected in this year's higher PV and wind capacity growth forecasts, compared with *Renewables 2017*. For **ASEAN** countries, the forecast has been revised up, mostly based on higher PV deployment with better regulatory frameworks and economic attractiveness throughout the region, as well as greater wind deployment following policy changes in Viet Nam and enlarged project development in the Philippines.

In **Latin America**, Brazil's renewable capacity is expected to increase 21 GW, led by hydropower, onshore wind and solar PV, with notable contributions from bioenergy. Improvement in several main macroeconomic indicators encourages a more optimistic outlook for renewable financing. Having successfully implemented its renewables auction scheme, Argentina is emerging as an important growth market, and with concessional financing and offtaker guarantees available, the economic attractiveness of wind and solar projects has improved significantly. However, timely grid connections and macroeconomic uncertainties are still key forecast uncertainties.

Renewable power capacity in **sub-Saharan Africa (SSA)** is set to expand from 37 GW to 64 GW over the forecast period. This represents only 2.5% of the global growth, but surpasses that of the Middle East and North Africa (MENA) and Eurasia. Hydropower continues to lead expansion, with most new projects in Ethiopia, Nigeria, Angola and Zambia. However, enlarged use of capacity auctions, coupled with other supportive policy measures and falling technology costs, drive non-hydropower deployment across the region. Solar PV technology is expected to expand across SSA: on-grid installations are dominated by utility-size projects driven by capacity auctions and access to international financing. Off-grid PV applications bypass grid and land acquisition problems and are incited by increasing demand for electrification and expanding private sector opportunities in this niche market. Wind deployment leaders are South Africa, where it is stimulated by auctions, followed by Ethiopia and Kenya, which offers feed-in tariffs.

MENA's renewable capacity is forecast to increase 85% (23 GW), with almost three-quarters of this growth from solar PV and CSP technologies owing to their increasing economic attractiveness. Competitive auctions in MENA countries continue to produce some of the world's lowest tariffs for PV and CSP as a result of the region's excellent resource potential, technology cost reductions, and access to favourable financing conditions. Commercial PV deployment is accelerating because it is increasingly economically attractive under net-metering schemes and higher retail electricity prices in some countries. Bilateral contracts and auctions propel onshore wind deployment in Morocco, Egypt and Jordan, while most large hydropower development continues to occur in Iran. However, currency risks, financing, and obstacles for new market entrants are key challenges for some countries in the region.

Accelerated case technology and regional summaries

In the accelerated case forecast, renewable capacity growth over 2018-23 could be 25% higher than in the main case, reaching 1.3 TW, if governments address policy, regulatory and financial challenges in the next 12-24 months (Table 2.3). Solar PV alone represents half of additional accelerated case growth: driven by faster cost reductions that make the technology more cost-competitive globally, annual additions are expected to reach 140 GW by 2023 (Figure 2.4). Together, commercial, residential, and off-grid PV applications account for most of the extra growth, indicating untapped potential in these segments, especially China, India, Europe, and Latin America.

Onshore wind capacity growth could be 25% higher globally, raising annual additions to over 60 GW over the forecast period, and the contribution of offshore wind in the accelerated case is notable owing to faster commissioning of planned projects not only in the European Union and China, but in the United States, Viet Nam and Chinese Taipei. Additional hydropower deployment in the accelerated case depends on faster development of planned projects, including a considerable amount of pumped storage in Europe, MENA and Australia. In other renewables, bioenergy accounts for over 80% of additional deployment, mainly in China, the European Union, India, and Japan.

Figure 2.4 Main and accelerated case forecasts of annual capacity additions by technology, 2017-23

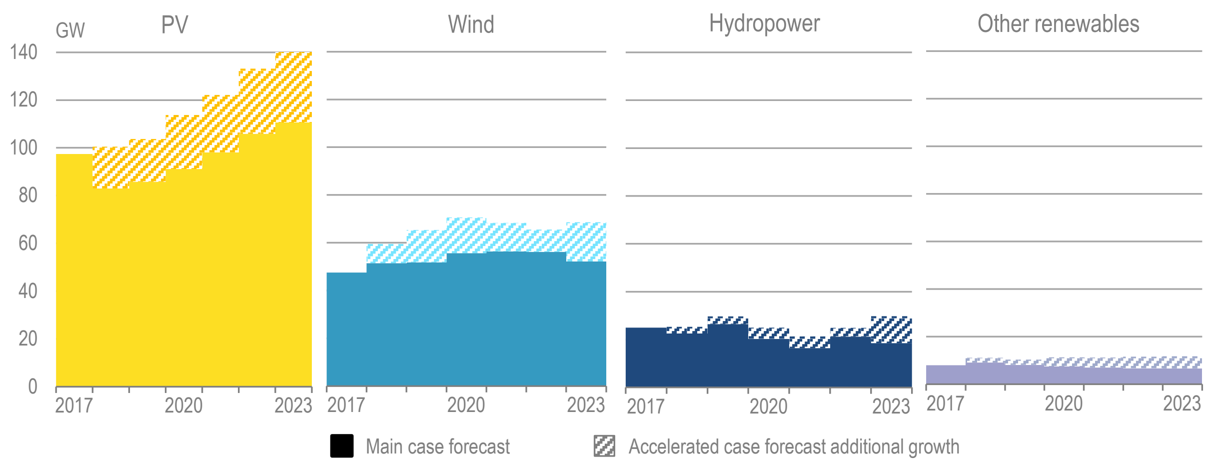


Table 2.3 Policy and market development assumptions in the accelerated case forecast for selected countries/regions

Region	% of global upside potential	Policy
China	38%	• Smooth transition from FITs to RPSs with clarity on the new remuneration scheme for renewables, including distributed generation • Larger auction volumes for wind and solar PV projects • Faster implementation of power sector reforms, and retail competition raises economic attractiveness of distributed solar PV • Faster commissioning of hydropower projects and transmission lines enables further integration of all renewables
EU	12%	• Increased auction activity to meet 2020 targets and longer-term climate goals • Improved economics for self-consumption, corporate PPAs • Easier permitting procedures for onshore wind and faster construction of offshore projects under development • Greater levels of interconnection among network areas
India	11%	• Accelerated pace of solar PV auctions and project development • Improved financial health of distribution companies and clarification of policies for distributed generation • Faster expansion of grid, allowing faster project development
MENA	4%	• Faster implementation of planned auctions • Accelerated phase-out of retail electricity subsidies • Increased pumped-storage plant development (Morocco, Egypt, UAE, Israel, Iran)
USA	10%	• Limited impact of tax reforms on the tax equity market and on the cost of capital • Increasing number of projects qualifying for federal tax incentives before the phase-out • Faster reduction of balance of system costs, and improvements and clarifications in state-level policies for residential and commercial PV • Faster growth of corporate PPAs for new utility-scale solar and wind projects
SSA	3%	• Faster commissioning of projects already in development • Smooth running of future auctions with timely PPA signing and financial closure
LAM	4%	• More favourable macroeconomic indicators enable lower-cost financing • Additional auction volumes for wind, solar PV and bioenergy technologies • Regulatory improvements enabling faster deployment of distributed PV • Faster commissioning of large-scale hydropower projects

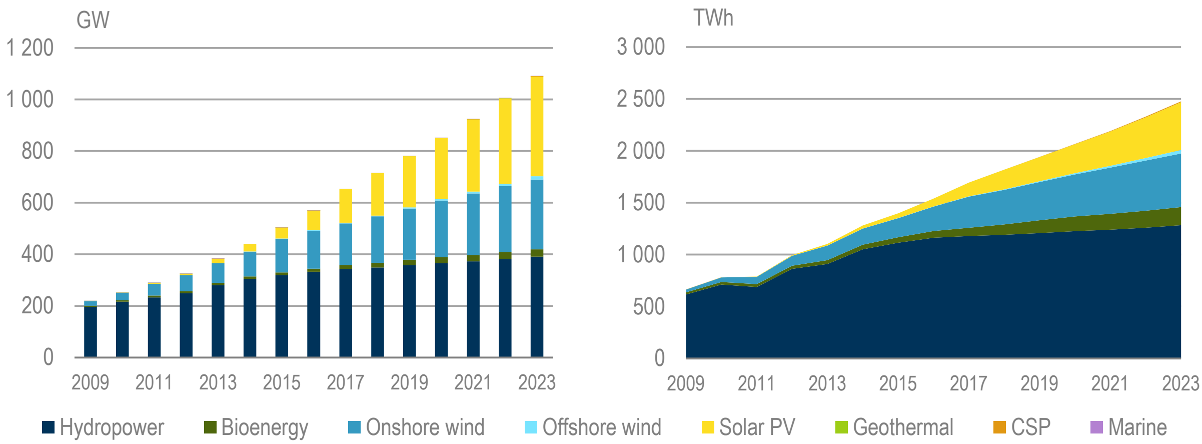
Notes: LAM = Latin America; UAE = United Arab Emirates.

China

Main case forecast

China's renewable energy capacity is forecast to expand 67% (438 GW) to just over 1 TW in 2023, with growth spurred by government policy support to tackle local air pollution and decarbonise the power mix (Figure 2.5). Solar PV accounts for 58% of total renewables expansion, followed by wind including offshore projects (120 GW), hydropower (47 GW) and bioenergy (14 GW). By 2023, non-hydro renewables account for 48% of China's 2 500 terawatt hours (TWh) of renewable generation. Renewable policies to reduce the cost of subsidies and curtailment strongly influence this year's forecast, especially for solar PV.

Figure 2.5 China: Total renewable capacity (left) and generation (right), 2009-23



Source: Historical capacity data for OECD countries based on IEA (2017), *Renewables Information 2017*, www.iea.org/statistics/.

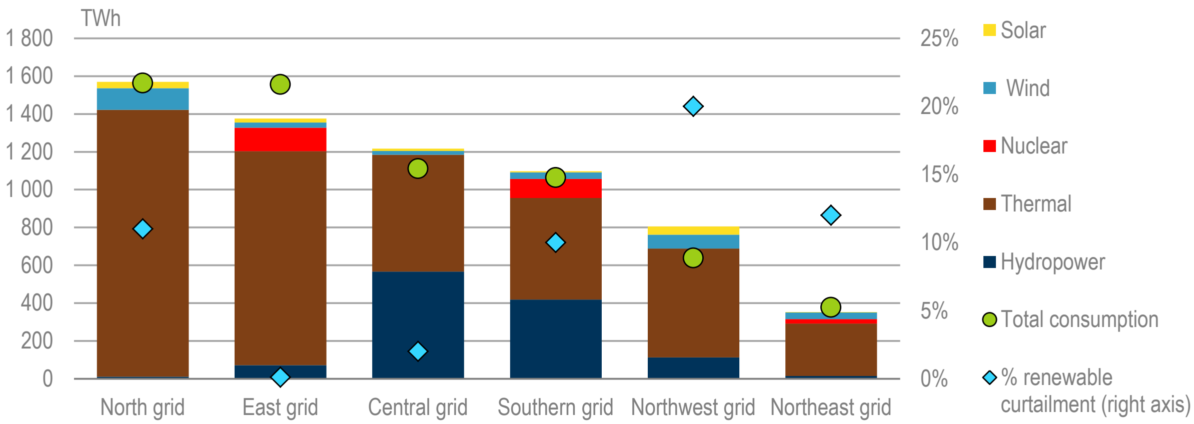
Because the government decided to phase out solar PV FITs more quickly than announced and introduced capacity quotas for distributed PV generation, PV capacity additions are anticipated to slow in 2018 compared with the exceptional growth in 2017, but to expand substantially nevertheless owing to increasing competitiveness. Faster development of planned large hydropower plants and higher government targets for bioenergy signal a more optimistic outlook for these technologies. However, onshore wind and CSP forecasts are less hopeful due to system integration challenges for onshore wind and slower development of CSP demonstration projects.

China's regional electricity mix and renewables curtailment

In 2017, China's total electricity generation increased 6% – in line with 2016 despite the increase in net installed electricity capacity at almost 8% (127 GW). Renewables including hydropower represented two-thirds of this growth, with coal power plants providing the majority of the remaining. Coal still fuels two thirds of China's electricity generation followed by renewables (26%), nuclear and natural gas. Due to the limited flexibility of its current fleet, China curtailed 12% of its wind, 6% of its solar PV and 4% of its hydropower generation in 2017, exceeding 100 TWh overall, i.e. close to the Netherland's total electricity consumption. However, wind curtailment had declined by five percentage points y-o-y in 2017 as a result of much faster power demand growth, construction bans on new wind projects in areas with high curtailment, and the commissioning of new transmission lines connecting western regions to demand centres in the east.

China's regional electricity mixes and provincial power generation and consumption dynamics pose critical grid integration challenges for renewable energy deployment over the forecast period (Box 2.1). In Northwest China, local generation currently exceeds demand, so transmission bottlenecks still occur despite network infrastructure improvements (Figure 2.6). The region has the second-largest installed variable renewable capacity and the highest wind and solar curtailment rates, especially in Gansu and Xinjiang.

Figure 2.6 China: Electricity generation and consumption, and renewable energy curtailment by region, 2017



Source: IEA analysis based on CEC (2018), "2017 electricity and other energy statistics".

In the North and the Northeast regions, wind curtailment improved in 2017. However, renewable energy curtailment may increase again in some provinces as developers are now allowed to build new wind plants in Inner Mongolia and Heilongjiang, and utility-scale solar PV capacity has expanded rapidly since 2015. In southern China, hydropower accounts for 40% of local generation with limited transmission capacity and growth in wind and solar capacity in recent years has exacerbated renewable energy curtailment in the region. The East China region has the only grid area free from curtailment, but some is expected to emerge over the forecast period due to rapid solar PV deployment and transmission constraints.

Box 2.1 System integration challenges in China

China's grid integration challenges are the result of technical as well as regulatory and institutional issues. On the technical side, variable renewable energy (VRE) capacity is very high in some provinces, but grid capacity is insufficient to export generation because large-scale transmission projects have been delayed. Moreover, numerous highly technical challenges for handling very large ultrahigh-voltage direct current (UHVDC) links have caused grid integration issues, especially in the western provinces.[3] Chinese policy makers have been responding to this challenge by discouraging deployment in VRE hot-spot regions and encouraging more distributed deployment patterns. Notwithstanding this measure, continued delays in UHV transmission projects and operational issues will pose system integration challenges for years to come.

[3] The sudden loss of a large multi-GW HVDC line can create stability issues at both the sending and receiving ends. The State Grid Corporation of China has been working with wind technology developers to retrofit wind power plants with high-voltage ride-through capabilities as well as establish technical solutions at the receiving end, such as the 3.8-GW ultra-fast demand-response scheme in Jiangsu province.

However, regulatory and institutional challenges are arguably a more significant reason for curtailment. Chinese power system operations are based on the notion of fair dispatch, which means that it is decided in advance on an annual basis how many operating hours a certain power plant is expected to receive. This method and the underlying economic incentives have delivered a reliable power system with universal access in just a few decades. However, in the context of large power sector overcapacities, this type of system leads to general under-utilisation of all assets, without full consideration of their environmental and economic performance. In addition, arranging commercial electricity trading across large distances is difficult because of the strong incentive to rely on in-province generation rather than imports, as it boosts provincial gross domestic product (GDP).

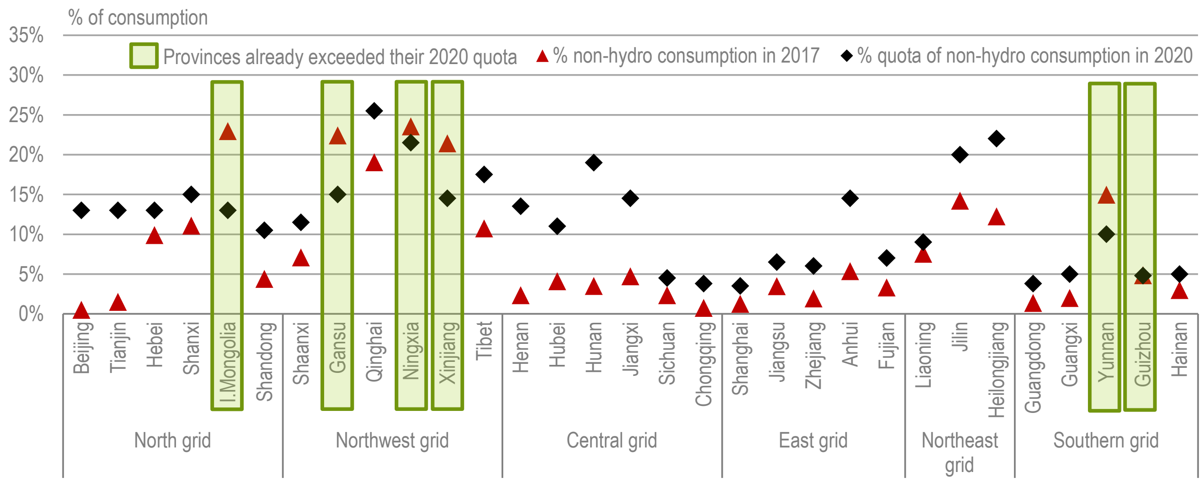
Several ongoing reforms are attempting to tackle this issue – particularly the power market reform initiated in 2015, which contains several elements that address these challenges. To avoid greater grid integration issues and possible curtailment, it is critical to: 1) implement an efficient dispatch system, 2) unlock trading among provinces, and 3) reform electricity prices to incentivise the uptake of flexible resources.

Renewable policies focus on system integration and subsidies

China's recent policies aim to achieve two main goals: first, to alleviate grid integration challenges, and second, to reduce the cost of renewable subsidies. In March 2018, the National Energy Administration (NEA) therefore proposed mandatory renewable generation quotas (for hydro and non-hydro energy sources) for each province for 2020 (Figure 2.7), whereby:

- Each megawatt hour (MWh) of renewable energy is eligible for a renewable energy certificate (REC).
- Electricity consumers, including grid companies, retailers and large-scale industrial consumers must prove they meet provincial targets by obtaining RECs.
- Consumers that cannot meet their targets at the end of each year must purchase additional RECs at a price defined by the National Development and Reform Commission (NDRC).
- The trading of RECs between consumers in different provinces is possible.
- Penalties for non-compliance include both fines and a ban on fossil fuel plant development in the province, but details are not yet known.
- Revenues from fines and penalties will support a renewables subsidy fund.

Figure 2.7 China: Renewable energy consumption by province in 2017 and quotas for 2020



Note: I. Mongolia = Inner Mongolia.

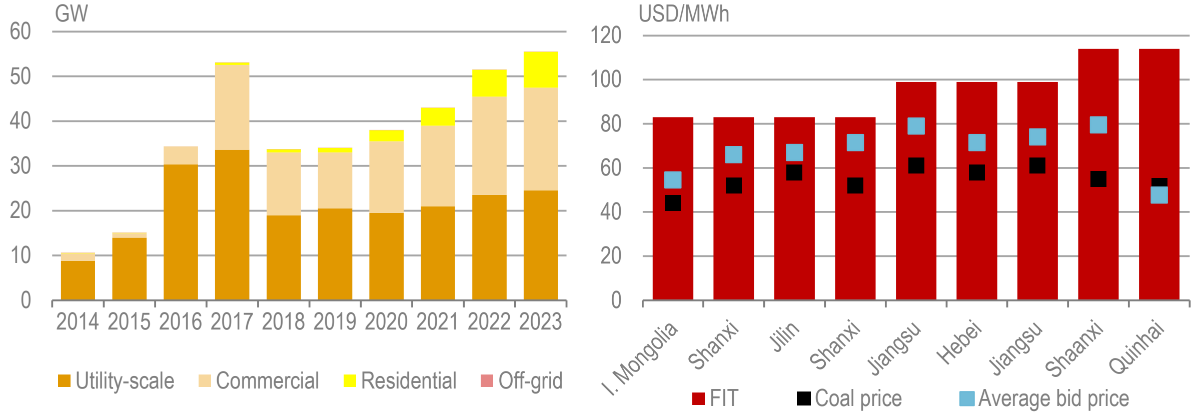
Sources: IEA analysis based on CEC (2018), "2017 electricity and other energy statistics"; NEA (2018), *Bulletin of Monitoring and Evaluation of National Renewable Energy Power Development*; NEA (2017), *National Notification Report on Monitoring and Evaluation of Renewable Energy Power Development.*

In 2017, five provinces (Inner Mongolia, Gansu, Ningxia, Yunnan and Xinjiang) located in the north, northwest and south grid areas had already reached their 2020 non-hydro generation targets. The NEA expects that these provinces will sell RECs to others to help them meet their targets. For instance, it will be very challenging for Beijing, Shandong and Tianjin in the north grid area to reach their targets by building all required new wind and solar capacity locally. It is important to note that the RECs are not the same as the voluntary green certificate system (GCS) introduced in 2017, which was supposed to become mandatory in 2018. The GCS will remain voluntary in addition to FITs.

China's **solar PV** capacity is expected to almost triple from 131 GW in 2017 to 386 GW in 2023, and the country is expected to account for 40% of global cumulative PV capacity at the end of the forecast period. However, after the joint announcement by the NEA, NDRC and Ministry of Finance in May 2018, annual capacity additions are expected to decline from the record 53 GW in 2017. The new regulation terminated FITs for new utility-scale projects and introduced a 10-GW annual capacity cap for distributed generation applications, both for 2018; the tariff for poverty alleviation projects remains the same. Overall, this policy shift is expected to make solar PV technology more cost-competitive in China, leading to more sustainable development over the longer term.

Utility-scale projects still made up almost two-thirds of the 53 GW commissioned in 2017, but this was a decline from 90% in 2015 and 2016. Annual solar PV deployment is forecast to shift from utility-scale projects to distributed applications, dominated by commercial and industrial projects, with a residential PV market emerging after 2020 (Figure 2.8). Utility-scale deployment is therefore expected to account for half of PV capacity growth over 2018-23, and this expansion is more cost-effective with the phase-out of FITs and the introduction of "Top Runner Program" competitive auctions.

Figure 2.8 China: Solar PV capacity additions, 2014-23 (left), and recent Top Runner auction winning bids (right)



In March 2018, the government awarded 4.5 GW of solar PV capacity in 7 provinces, with average winning contract prices ranging from USD 52/MWh to USD 80/MWh, 15-50% below local FITs. In many provinces, winning bids were only 15-20% higher than the average price that coal plants receive in those regions, while in Quinhai developers offered prices lower than those of coal. Government quota allocations for utility-scale projects will be reduced after 2018, with FITs phasing down through 2020; however, new annual quotas for 2019 onwards are a key forecast uncertainty. Utility-scale projects under the poverty alleviation programme are anticipated to continue stimulating 7.5 GW of PV capacity annually, as they fall outside the government quotas and are not part of the FIT budget. However, curtailment has been a challenge in Northwest China since record-level growth in 2015. In March 2018, the NEA banned development of new utility-scale PV projects in Gansu, Ningxia and Xinjiang, and bans may also apply to additional provinces over the forecast period.

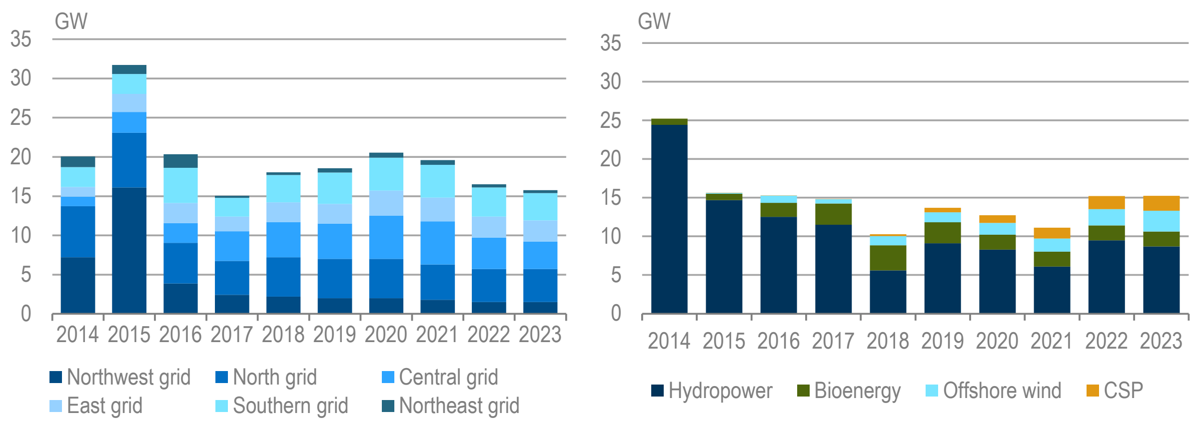
Commercial/industrial and residential projects are expected to grow much more quickly over the forecast period than they have historically, representing half of additional solar PV capacity expansion. Several drivers, policies and regulations are expected to boost distributed PV development:

- Investment costs for commercial and industrial applications are only 5-10% higher than for utility-scale projects because of their relatively large size (0.3 MW to 20 MW).
- Distributed generation owners can choose to use some energy for their own consumption and sell excess generation to on-site consumers. Commercial and industrial projects become economically attractive at high levels of self-consumption, as retail electricity prices for non-residential users range from USD 90/MWh to more than USD 165/MWh – 13-40% higher than for residential customers.
- In February 2018, the government introduced a new regulation lifting the administrative hurdles that prevent generators from selling electricity to multiple consumers connected to the same substation. This new regulation will increase the client base for distributed generators, enabling them to diversify their revenues and reduce risk, thus improving their financing conditions, which have been a major impediment to growth.

Commercial and industrial applications are expected to make up 83% of distributed PV capacity expansion, and the residential market remains small, as relatively higher investment costs and lower retail electricity prices hamper economic attractiveness. However, China's electricity market reform aims to introduce retail competition starting from 2020, improving the business case for residential applications. This forecast takes this into consideration, and expects greater residential PV growth after 2020.

Onshore wind capacity is forecast to expand 109 GW, with annual installations ranging from 16 GW to 21 GW. This growth is driven by FITs, competitive auctions, and the improved economic attractiveness of projects located in low and medium wind sites close to demand centres (Figure 2.9). In 2017, China connected only 14.5 GW of new onshore capacity, the lowest level since 2010, mainly due to the construction ban in some Northern provinces where curtailment levels reached 20-30% in 2016. As curtailment declined in 2017, however, the NEA lifted the ban in some provinces in North China, such as Inner Mongolia. Thus, in the short term, developers are expected to complete projects that were under development before the ban. However, the pace of deployment in northern regions remains a forecast uncertainty, depending on how quickly new transmission lines are commissioned.

Figure 2.9 China: Onshore wind capacity additions by region (left) and hydropower, bioenergy and CSP capacity additions, 2014-23



Meanwhile, wind developers will continue to exploit low- and medium-resource sites in the central, southern and eastern provinces closer to demand centres before the FIT phase-out in 2020. Investment costs for projects in these regions are higher than for those in the north because projects are smaller, land is more expensive and construction time is longer, despite a lower risk of curtailment. After 2020, annual additions are expected to decline due to the phase-out of FITs and uncertainty over the volume and design of the new auction scheme. **Offshore wind** is anticipated to expand 10.5 GW over 2018-23 thanks to attractive FITs. The forecast is more optimistic than last year owing to enlarged project development activity and further cost reduction potential.

Hydropower capacity grows from 344 GW in 2017 to over 391 GW in 2023, meeting the 2020 target in 2022. China's annual hydropower installations peaked in 2014 and declined thereafter, with less than 12 GW becoming operational in 2017. Overall, the forecast is more optimistic because construction has begun on the Baihetan project (16 GW), the world's second-largest hydropower plant. Despite rising social and environmental concerns over mega-projects, the majority of Baihetan's turbines are expected to be operational by 2023. PSH plants account for almost 40% of China's hydropower expansion over the forecast period because they help integrate VRE into the system.

Bioenergy capacity is expected to increase 13.7 GW over 2018-23, meeting the 23-GW target for 2020 in China's 13th Five-Year Plan (FYP). In addition to bioenergy's increased contribution in the 13th FYP made in 2017, other factors informing the upward revision of this forecast include 50% higher annual capacity additions (2.7 GW) in 2017 than in 2016, and a new clean-heat initiative to deliver a further 3.8 GW of electricity capacity through biomass co-generation during the first half of the forecast period.

EfW made up most bioenergy capacity additions in the last five years and is also prominent in the bioenergy forecast, overtaking agricultural residues as the largest source of cumulative bioenergy capacity. Robust deployment is anticipated until 2023 and beyond as increasing urbanisation creates pressing waste management needs. Also, promoting the use of agricultural residues for EfW (as an alternative to uncontrolled in-field burning that deteriorates air quality) will boost deployment. Both EfW and solid biomass-based electricity generation receive FIT support; in addition, China announced a new policy on biomass co-firing in 2017 that will enable pilot projects for coal power stations to begin co-firing biomass and receive financial support. Eighty-four plants have been selected, for a potential 20 TWh of bioenergy generation per year.

The 13th FYP proposes a target of 5 GW of **CSP** by 2020. In August 2016, 20 demonstration plants (total 1.3 GW) supported by the FIT were nominated, with commissioning expected by the end of 2018. Of these, seven projects (450 MW) are currently expected to be commissioned within the deadline and four more (200 MW) have reached the advanced stages of construction. Additions of 1.9 GW are anticipated over 2018-23, as this year's forecast has been revised down 30% to reflect a 50% completion rate for the demonstration projects and currently no outlook for additions. The relatively high cost of CSP technology and limited developer experience remain key challenges to growth.

Accelerated case forecast

China's renewable capacity growth could be 17% (75 GW) higher than in the main case forecast over the next six years, depending on the pace of policy implementation to tackle VRE grid integration problems, electricity market reform and increasing renewables subsidies. The remuneration scheme replacing FITs after 2020 is an important forecast uncertainty, however. China has already introduced a national mandatory renewables quota system with RECs, a voluntary green certificate market, and provincial carbon and wholesale electricity markets; the harmonisation and optimisation of these policies will determine whether this more cost-effective remuneration scheme can provide long-term revenue certainty to renewables after the FIT phase-out. In addition to these policy improvements, selected technology-specific conditions must also be met (Table 2.4).

Table 2.4 China: Conditions of accelerated case forecast and cumulative capacity by 2023

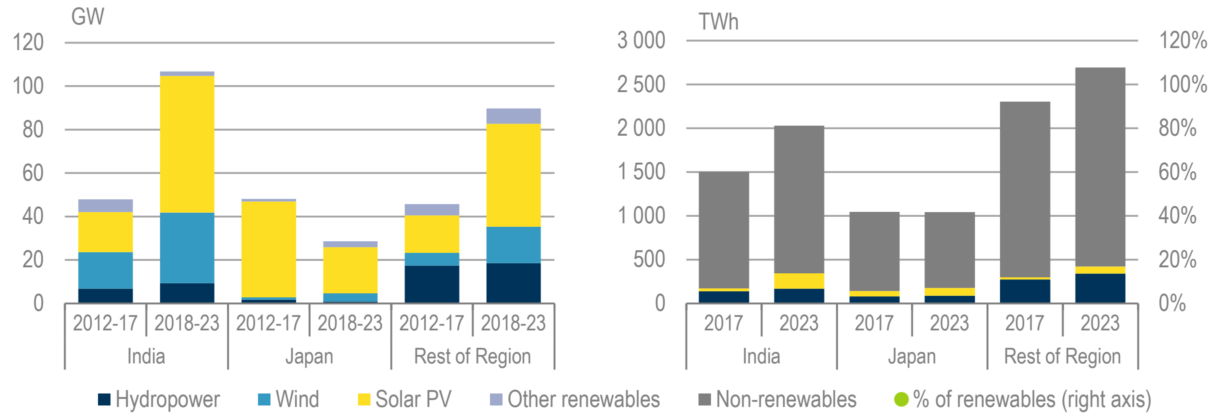
	Conditions for the accelerated case	Main case	Accelerated case
Hydropower	• Faster commissioning of projects already under construction, including the Baheitan plant • Faster approval of environmental permits for planned large and small-scale projects	391 GW	405 GW
Wind	• Accelerated commissioning of transmission lines to reduce curtailment in northern provinces • Larger auction volumes in 2021-23 • Faster approval and development of offshore wind projects, including transmission infrastructure	283 GW	300 GW
Solar PV	• Accelerated cost reductions and improved competitiveness of utility-scale projects • Faster commissioning of Top Runner auction projects and introduction of additional auctions • Wider implementation of retail competition to improve economic attractiveness of distributed solar PV projects • Affordable financing for residential PV projects • Market design enabling electricity sales to multiple consumers connected to the same substation	386 GW	422 GW
Bioenergy	• Enhanced public consultation to gain support for EfW • Measures to counter fuel price escalation • Continuation of the biomass co-generation initiative • Measures to build supply chains for agricultural residues	29 GW	37 GW
CSP	• Faster commissioning of demonstration and planned projects with performance improvements	1.9 GW	2.5 GW

Asia-Pacific

Renewable electricity capacity in the Asia-Pacific region, excluding China, is forecast to grow 64% or 225 GW over the forecast period, dominated by deployment in India, Japan, ASEAN countries, Korea and Australia (Figure 2.10). Solar PV leads the expansion with 132 GW, followed by onshore wind (48 GW) and hydropower (29 GW).

The region's overall forecast has been revised upward from last year owing to higher anticipated solar PV growth resulting from ambitious targets and auctions in India, a rush to take advantage of expiring policy support for utility-scale applications in Australia, generous FITs in Japan and supportive regulatory changes complemented by greater economic attractiveness throughout the ASEAN region.

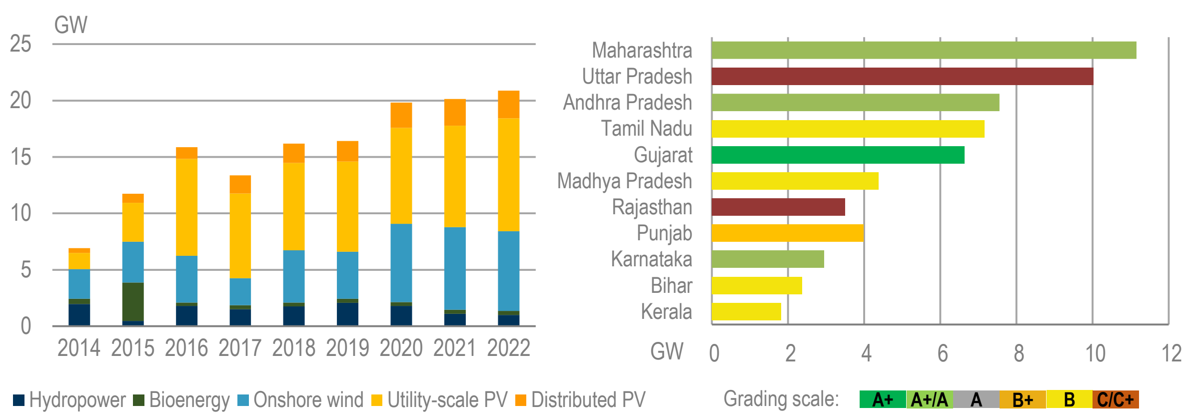
Figure 2.10 Asia-Pacific: Renewable electricity capacity growth, 2012-23 (left), and generation by source, 2017-23 (right)



India: Main case forecast

India's renewable energy capacity is forecast to double over 2018-23 as ambitious government targets and supportive policies at both the national and state level spur additions of 107 GW (Figure 2.11, left). Almost 60% of the growth is from solar PV (63 GW) and onshore wind (33 GW), mostly contracted through competitive auctions that have received increased central government commitment since tender trajectories to reach the 2022 targets of 100 GW of solar PV and 60 GW of wind were announced in November 2017. Annual capacity additions are expected to slow in 2018 (mainly in onshore wind) because the transition from India's generation-based incentive (GBI) to competitive auctions is anticipated to create a lull in project pipeline.

Figure 2.11 India: Capacity additions, 2014-23 (left), and solar PV capacity needed to reach 2022 targets vs financial health of utilities per state as of July 2018 (right)



Note: The A+ to C grading scale reflects the operational and financial health of DISCOMs based on a rating framework approved by the Ministry of Power (2018). The assignment of state grades is based on the weighted average of grades assigned to state distribution utilities in the sixth annual integrated rating (IEA 2018b).

The financial health of India's state distribution companies (DISCOMs) remains a key factor influencing the forecast. Despite improvements in the last five years, the cost recovery rate of Indian

DISCOMs at the national level was 81% in the 2017 fiscal year (IEA, 2018b). The UDAY scheme, which seeks to alleviate high debt and interest cost burdens, has improved the financial health of some DISCOMS over the past year, but its impact varies considerably across states. It is estimated that at least 40% of capacity additions needed to meet India's 2022 solar PV target are allocated to states with below-average to very low operational financial performance capability (B-C grading scale) (Figure 2.11, right). The financial health of these utilities is anticipated to improve over the forecast period, but delayed subsidy payments by state governments compromise their ability to sign renewable PPAs in a timely fashion at awarded prices. The extent to which this offtake risk affects the forecast likely depends on how much future capacity is tendered by central public sector entities (NTPC Limited and the Solar Energy Corporation of India [SECI]), which provide better payment security.

In addition, system integration of renewables remains an important challenge to renewables deployment over the forecast period. While progress in strengthening and expanding both inter- and intra-state transmission lines continues under the Green Corridor project, concerns have been raised over whether sufficient financing has been allocated to meet 2020 targets for transmission line installation (MNRE, 2018).

Box 2.2 System integration of renewables in India

Although India's power sector still faces significant challenges, the country has already made tremendous progress in preparing its power system for the arrival of renewable energy. It established a single synchronous power system across the entire country in 2013 with an increasingly robust transmission grid, and the Green Corridors initiative is expected to further extend these efforts to integrate new renewable energy capacity.

However, a number of challenges remain, related to establishing a forward-looking grid code and effective forecasting systems for renewable energy, unlocking flexibility from thermal power plants, enhancing electricity trade among states and systematically developing innovative flexibility resources, notably demand-side response and storage. At the national level, government agencies and power sector stakeholders have been prioritising system integration by implementing numerous technical analyses and regulatory measures, but not all these efforts have gained full traction at the state level, limiting their effectiveness.

Thermal power plant flexibility is a good example of two-tiered (national and state-level) development. The Central Electricity Regulatory Commission issued regulations requiring all central power plants, i.e. those subject to federal jurisdiction, to lower their minimum generation levels from 70% to 55% of nameplate capacity. This had a strong positive impact on the operational flexibility of the system, because central plants constitute 50 GW of 224 GW of coal capacity. However, states have been slow to pass similar regulations for complex institutional and commercial reasons. From an institutional perspective, the division of federal and state jurisdiction means that each state must pass its own regulations regarding plant flexibility. From a commercial perspective, existing PPAs with thermal generators can become an obstacle to making what is technically possible also contractually viable.

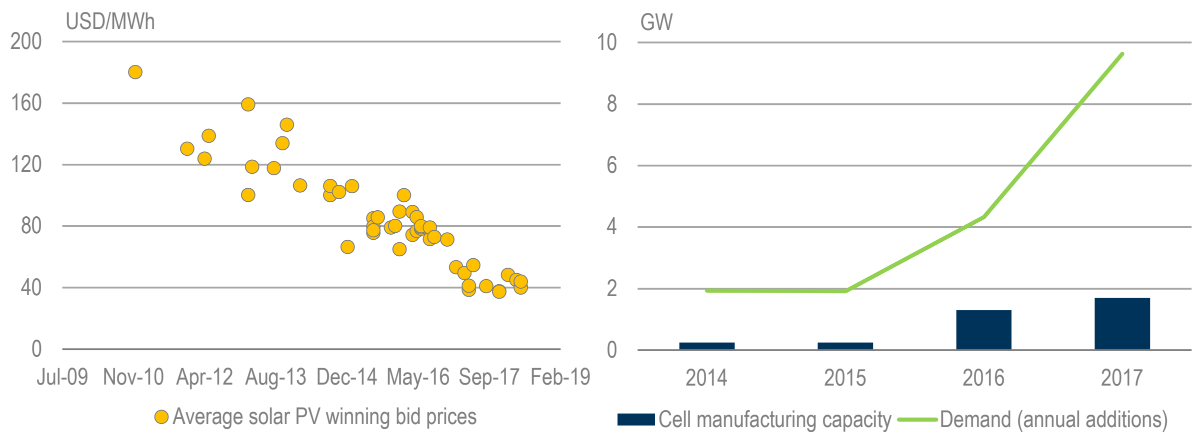
PPA inflexibility is also a critical barrier to making trade among states more meaningful. The physical obligations of power plants to deliver to specific DISCOMs leave little room for power imports from other states. This issue has been exacerbated by considerable thermal generation overcapacity in some states, meaning that DISCOMs already pay considerable fixed costs for power plants and hence have little incentive to import power. In addition, power markets are not fully developed: while a day-ahead market exists, there is no intraday market and system services markets are still in a nascent stage.

Establishing renewable energy forecasting centres is another priority issue that has been identified, but implementation has yet to take place in most states. For instance, the state of Tamil Nadu in southern India very successfully introduced a wind forecasting system in 2015 that has reduced curtailment and increased the amount of integrated wind generation, but similar systems have not been deployed in all states experiencing rapidly rising VRE generation.

Beyond 2022, systematic improvements to system flexibility, including through innovative resources such as advanced demand-side response and – when cost-effective – electricity storage, will be crucial.

Solar PV leads India's renewable capacity growth at a 63-GW increase over 2018-23, with utility-scale applications accounting for 80%, stimulated by both federal and state-level competitive auctions for independent power producers (IPPs) and engineering, procurement and construction (EPC) projects. To address land acquisition and grid integration challenges, government plans for solar park auctions were raised from 20 GW to 40 GW, allocating land and transmission infrastructure to winning projects within the parks. Furthermore, the Ministry of New and Renewable Energy (MNRE) recently amended guidelines for competitive bidding with provisions to reduce offtake risk, address revenue shortfall from curtailment, and minimise delays related to land acquisition. Meanwhile, average PV auction prices declined one-third from USD 70/MWh in 2016 to USD 46/MWh in 2017 (Figure 2.12) – comparable with coal-generated electricity prices in some states. This price drop has made solar PV technology more attractive for some DISCOMs, but has also increased the risk of contract renegotiations or cancellations for projects previously awarded at much higher prices. For instance, only 700 MW of the 1.1 GW initially awarded in Jharkhand's 2016 auction signed PPAs after one year of contractual negotiations, at prices lower than those originally bid.

Figure 2.12 India: Average PV winning bids, 2009-20 (left), and domestic cell manufacturing vs demand, 2014-17 (right)



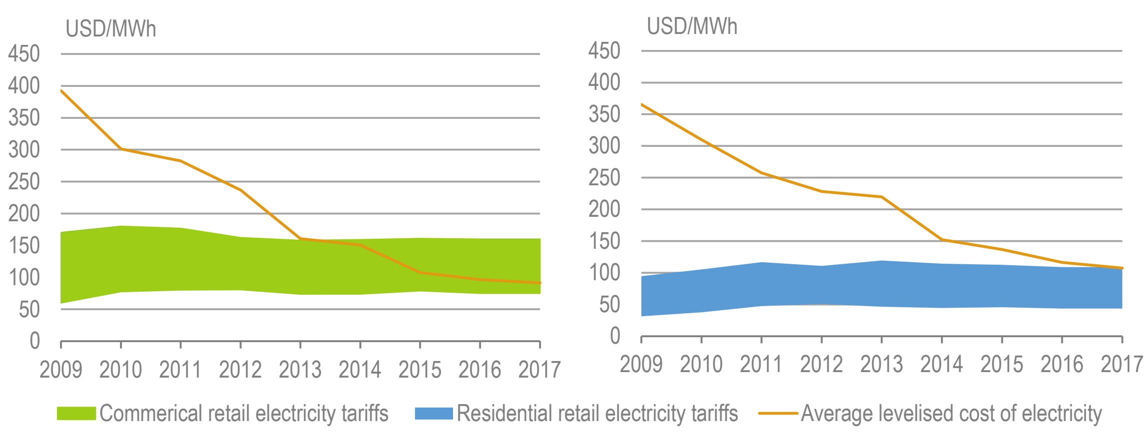
Note: Average winning solar PV bid prices may include support for investment costs (accelerated depreciation or viability gap funding).

Sources: IEA PPA database (left); IEA analysis (right).

India's solar PV market remains price-sensitive for both DISCOMs and project developers. DISCOMs seek to buy lower-priced power to improve their financial health while PV developers bid aggressively with very low margins to win contracts, betting on faster module price declines. Thus, any policy change or market development that affects module prices may also influence project bankability. For this reason, the recently introduced goods and services tax (GST) and a 25% safeguard duty on solar cells and modules imported from China and Malaysia (which supply the majority of local demand) have created forecast uncertainty. Any price increases may lead DISCOMs to ask for tariff reviews and potentially result in project delays: for instance, the government of Gujarat cancelled a 500-MW auction after deeming the wining tariffs to be too high (Mercom, 2018b).

Distributed PV capacity is forecast to grow 12 GW, with growth in the commercial segment[4] accounting for over 90% owing to economically attractive economics for self-consumption, and limited uptake from net-metering schemes. With average PV generation costs of USD 79/MWH to USD 114/MWh in 2017 (lower than most retail tariffs for large consumers), self-consumption, supported by various third-party business models, is expected to remain a key driver for the commercial segment going forward (Figure 2.13). Additional commercial-scale capacity is expected to come from government tenders for rooftop applications on private institutions and public buildings. The economics for self-consumption in the residential sector remain challenging, however, despite the introduction of capital subsidies due to relatively low electricity prices and difficult financing conditions. For both segments, growth under the net-metering schemes in various states is hindered by caps on system size and injection, lengthy multi-step approval process, and the poor financial health of DISCOMs. However, some of these impediments may be addressed by recently introduced innovative policy mechanisms such as the Sustainable Rooftop Implementation for Solar Transfiguration of India (SRISTI) scheme, which is set to provide incentives to DISCOMS to help spur rooftop deployment (CEEW, 2018). In addition, the impacts of recently imposed taxes and proposed trade tariffs on system costs are uncertain and may lower the attractiveness of distributed PV technology, especially in the commercial segment.

Figure 2.13 India: Average solar PV levelised cost of energy vs commercial prices (left) and residential retail prices (right)



Sources: Analysis based on BNEF (2018b), *Prices and Tariffs* (database) and IRENA (2018), *IRENA Renewable Cost Database*, dataset provided to the IEA.

[4] Public, private, and industrial consumers that are neither residential nor sell power as their primary economic activity.

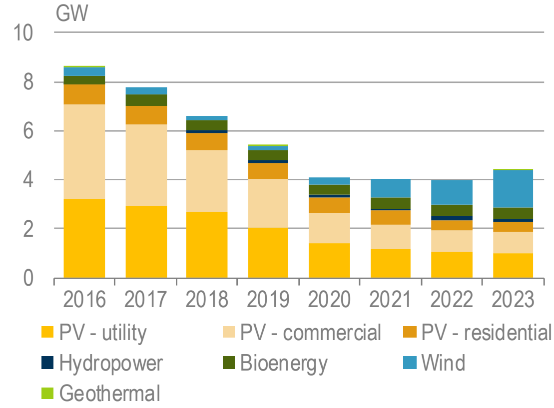
Onshore wind capacity grows 33 GW over the forecast period, mostly driven by competitive auctions. With this expansion, cumulative capacity reaches the government's target of 60 GW between 2022 and 2023. Record-level additions were achieved in 2017 (4.1 GW) owing to a developer rush to lock in support under the expiring GBI and decrease in accelerated depreciation. Deployment levels for 2018 are anticipated to be lower due to fewer residual GBI projects under development, and some deployment from the first auctions held in 2017. Over 2019-23, stable growth of 4 GW to 7 GW is expected, depending on the pace of auctions, which recently benefitted from increased visibility in November 2017 when the government announced its plan to auction 10 GW per financial year. However, cancelled and re-launched auctions that could delay deployment pose the greatest uncertainty to the forecast. In August 2018, the central government cancelled its latest tender for 2 GW after concerns over insufficient interstate transmission capacity caused the auction to be undersubscribed by 800 MW (Mercom, 2018c), and the state of Gujarat cancelled a 500-MW tender over developer requests to modify bid requirements (Mercom, 2018a).

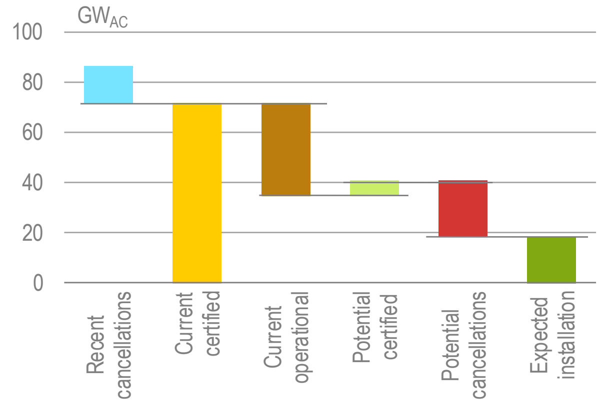
Hydropower capacity is forecast to grow 9 GW, mostly from large projects currently under construction. The pace of deployment will depend on project completion timelines, which are uncertain due to cost overruns and long lead times. Small-scale hydropower installations are also expected to contribute to the growth, supported financially by Central Financial Assistance. **Bioenergy** capacity increases just over 2 GW to 11 GW by 2023, meeting the national 10-GW target for 2022 ahead of schedule. Capacity growth comes primarily from bagasse residue co-generation in the sugar industry, boosted by a recently announced capital subsidy of USD 36 000 to USD 76 000 per additional MW of capacity delivered by investment in more efficient co-generation technology. Despite the need for better electricity access and favourable waste management rules advocating bioenergy, off-grid bioenergy and EfW deployment are anticipated to grow slowly. Low-level growth in these technologies results from difficulties associated with building fuel supply chains, challenging financing conditions and the absence of an overarching policy framework for bioenergy.

Japan: Main case forecast

Japan's renewable energy capacity is expected to grow 29 GW over 2018-23, with solar PV accounting for 74% of this expansion, followed by wind (3.9 GW) and bioenergy (2.6 GW) (Figure 2.14, left); growth is stimulated mostly by the country's generous FIT. The overall forecast for Japan has been revised up from last year to account for lower-than-expected cancellation of solar PV projects and continuous approval of new applications under the revised FIT scheme. Forecasts for biomass and wind are also more optimistic, as developers managed to secure FIT certification ahead of a scheduled tariff reduction. However, rapid growth in PV generation is expected to augment system integration challenges, especially in certain regions.

Figure 2.14 Japan: Annual net renewable capacity additions, 2016-23 (left), and estimated solar PV project cancellations and installations (right)





Notes: Right-side figure represents operational status of solar PV as of September 2017. AC = alternating current; 'Current cancellation' refers to cancelled projects that used to receive FIT approval but lost eligibility because they could not submit grid connections by March 2017; "potential cancellations" rate = 50%.

Sources: METI (2018a), "Solar PV cancellation with enforcement of revision of Feed-in Tariff Act"; METI (2018b), *Statistics of Renewable Energy in the Feed-in Tariff Scheme*; historical capacity data for OECD countries based on IEA (2018c), *Renewables Information 2018,* www.iea.org/statistics/.

Solar PV technology remains central to renewable capacity growth in Japan, with 21 GW to become operational thanks to a FIT for distributed generation and auctions for new utility-scale projects. In 2017, Japan's annual PV capacity additions declined for the second year in row by over 10% to 7 GW due to FIT cancellations and limited new project approvals (Figure 2.14, right). Although annual additions continue to decelerate over 2018-23, this year's forecast is more optimistic than last year's because project cancellations under the new FIT regulation were 50% less (14.6 GW) than anticipated. In fact, the Ministry of Economy, Trade and Industry (METI) approved an additional 1.8 GW of commercial and residential projects under the FIT in the first half of the 2017 fiscal year. However, new FIT approvals and additional project cancellations remain a key forecast uncertainty. New projects are required to secure grid connections prior to final FIT approval and are expected to contribute to grid enhancement, which may increase investment costs for some developers. In addition, METI decided to reduce the FIT for commercial projects by 14% to JPY 18 per kilowatt hour (/kWh) (USD 165/MWh), which applies to over 40% of Japan's PV growth over the next five years, followed by residential applications (16%).

Utility-scale solar PV projects are expected to grow 9 GW with the commissioning of previously approved FIT projects and auctions introduced last year to achieve more cost-effective deployment. In November 2017, Japan awarded only 140 MW of 500 MW of PV capacity, with the lowest bid at JPY 17.2/kWh (USD 150/MWh), 18% below the latest FIT. As winning projects were required to get grid connection approval just three months after the bidding, most developers did not want to take the risk of losing their deposit and decided not to bid. It is forecast that only 40 MW will be built because 100 MW was cancelled as developers failed to submit their second deposits. In September 2018, the second PV auction ended with no winners as all bids were above the ceiling price of JPY 15.5/kWh (USD 135/MWh) which was only announced after the bidding. The government will continue to hold additional auctions, but the rules are being modified to attract more competition and an additional 250 MW auction capacity is expected to be commissioned over 2020-23. Grid integration continues to be an important forecast uncertainty for PV technology, as curtailment issues persist in certain regions, such as Kyushu, that have limited interconnection capacity and where solar PV output is at a maximum during periods of low demand.

Bioenergy capacity is forecast to grow 2.6 GW, to reach 6.2 GW by 2023, mainly driven by the country's generous FIT scheme: biomass developers rushed to apply for FIT certification before a scheduled 12% reduction in the FIT tariff (from JPY 24/kWh [USD 210/MWh] to JPY 21/kWh [USD 190/MWh]) took effect. As of September 2017, almost 12 GW of wood biomass projects had received FIT approval, but it is anticipated that only 20% of this capacity will be commissioned due to challenges in obtaining biomass fuel supplies and financing. Limited domestic biomass fuel availability also means that wood pellet and palm kernel shell imports will likely increase during the forecast period. A first biomass auction for 200 MW of capacity is set for December 2018. **Wind** capacity is forecast to expand 3.9 GW, with 0.7 GW in offshore projects, as wind project developers rushed to apply for FIT certification before a scheduled 5% tariff reduction took effect. However, grid connection capacity is limited in areas where wind is abundant, and the lengthy timelines of environmental impact assessments continue to confront developers. **Hydropower** grows 0.8 GW over the forecast period, with mostly small and medium-sized applications deployed.

Other countries in the Asia-Pacific region: Main case forecast

In **Korea**, renewable energy capacity is expected to double to 32 GW in 2023, led by solar PV (11.4 GW) wind (2.7 GW) and bioenergy (1.5 GW). This is more optimistic than last year's forecast owing to the approval of more ambitious renewable energy targets to increase the share of renewables in the power mix from just under 8% today to 20% by 2030. In December 2017, the government announced its Implementation Plan for Renewable Energy 2030, under which renewable capacity quadruples by 2030. A higher RPS target with price multipliers for each renewable technology, auctions for utility-scale renewables, and additional financial incentives for small-scale solar PV will drive renewable expansion over the forecast period.

In April, the Korea Energy Agency (KEA) awarded 250 MW of solar PV at an average price of USD 160/MWh – exceeding global standards thanks to a generous RPS multiplier. In addition, the subsidiaries of KEPCO, Korea's largest utility, awarded 581 MW of projects (541 MW of solar PV and 40 MW of wind) in six auctions with fixed-price energy contracts to improve developers' revenue certainty because they are subject to volatile green certificate and energy prices. Bioenergy continues to contribute to Korea's RPS, providing over one-third of total renewable electricity generation by 2023 through dedicated biomass projects, coal-to-biomass conversion projects and co-firing, despite a lower RPS multiplier. The offshore wind market is expected gain ground slowly over the forecast period, but limited developer experience and a sluggish permitting process are key challenges to its growth.

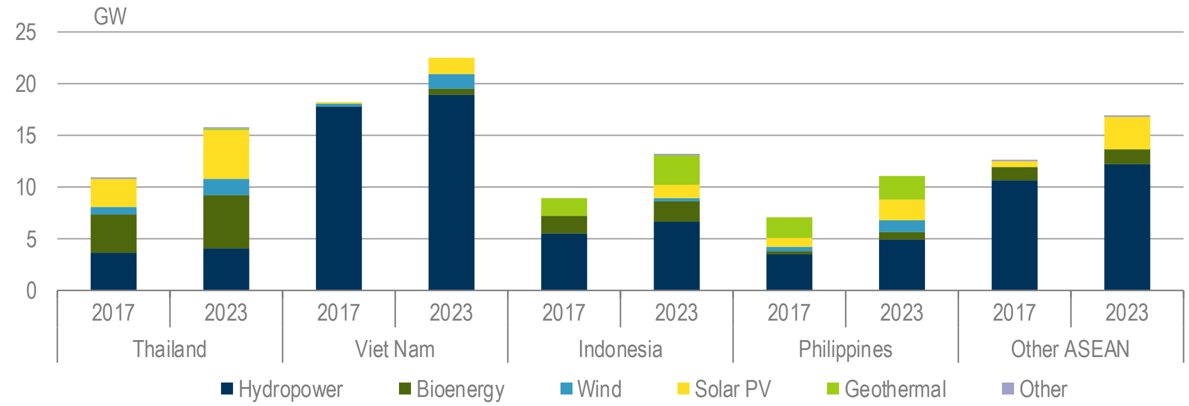
Renewable energy capacity in **Australia** is expected to grow over 90% (19.7 GW) over the forecast period, with solar PV dominating three-quarters of the expansion, followed by onshore wind (5.1 GW), hydropower (0.9 GW) and CSP (0.2 GW). Utility-scale solar PV and onshore wind projects are responsible for most short-term growth, dictated by the 2020 commissioning deadline of the Large-scale Renewable Energy Target (LRET). After 2020, annual utility-scale additions are expected to decline significantly, as the renewables incentives under Australia's new National Energy Guarantee policy remain uncertain. For distributed PV, high electricity prices, a generous national rebate programme and state-level FITs and feed-in premiums (FIPs) continue to drive growth. In 2017, retail electricity prices increased by 20-40% depending on the state, and according to the Australia Energy Market Operator (AEMO), they are to rise further in the short term for both residential and commercial customers (AEMO, 2017). This is expected to make self-consumption more economically attractive despite phasing down of the national grant programme from AUD 650/kW in 2018 to AUD 200/kW in 2023 and lower state-level incentives. Consequently, stable annual residential PV additions of around 0.8 GW (similar to the 2017 level) are forecast to continue, while commercial PV capacity grows more quickly as businesses aim to reduce their power bills.

Thailand's renewable capacity is expected to expand 45%, or 4.8 GW over 2018-2023 – 23% above last year's forecast due to the improved economic attractiveness of solar PV and the higher uptake of wind projects, boosted by recently signed PPAs. The government's 2036 renewable energy targets, based on the 2015 power development plan (PDP), are to be revised upwards, but their impact is a forecast uncertainty. **Solar PV** leads capacity growth (2.1 GW): in the short term, remaining capacities under the Agro Solar Phase II project and rooftop pilot programmes are anticipated to come online. After 2020, the new smart net-metering scheme and third-party PPAs support PV deployment to 2023. The details of these regulations have not yet been published, however, which raises forecast uncertainty. **Bioenergy** capacity is expected to increase 1.2 GW, driven by FITs and newly introduced hybrid-firm and semi-firm FIT mechanisms; biogas, solid biomass and EfW plants make up most of this growth. **Wind** capacity is forecast to double, growing 950 MW with the commissioning of projects developed under the previous FIP ('Adder') scheme: 11 projects that had stalled due to a dispute over land use rights were finally issued licences for a combined capacity of over 700 MW. However, public opposition and the uncertainty of additional capacity under the new competitive tender scheme continue to challenge deployment. **Hydropower** additions are anticipated to total 530 MW by 2023 with expansion of the Lam Takhong pumped storage hydropower (PSH) project (500 MW), and with some mini-hydro projects (<200 kW) stimulated by the FIT.

Renewable capacity growth of 47% (4.2 GW) is expected for **Indonesia** over the forecast period, led by solar PV, hydropower and geothermal (1.2 GW each) (Figure 2.15). The overall forecast is less optimistic for hydropower, bioenergy and wind, reflecting lower economic and electricity demand growth in the long-term electricity supply business plan.[5] However, revised regulations on procurement through fixed tariffs and competitive tenders, as well as improved PPA contracts, encourage a positive outlook for solar PV in some regions (Murdono Law, 2017; Norton Rose Fulbright, 2018; Hogan Lovells, 2018). **Geothermal** is forecast to grow 1.2 GW, in line with the electricity supply business plan, and financial support from the Clean Technology Fund is intended to overcome drilling risks. The **hydropower** forecast is driven by projects under the electricity supply business plan, which also postponed commissioning of the Upper Cisokan PSH project (1 GW) until after the forecast period. **Bioenergy** has been revised down, with only 0.3 GW expected over the forecast period due to limited project development during 2017 and persistent barriers relating to permitting, building fuel supply chains and the availability of suitable contractors and equipment. Pressing waste management challenges provide potential for EfW deployment; a programme to accelerate delivery of EfW plants in 12 major cities has been launched. Palm oil residue biogas should grow thanks to feedstock availability and attractive FIT tariffs.

[5] RUPTL (Rencana Umum Penyediaan Tenaga Listrik), is the ten-year electricity supply business plan of the state-owned utility PLN. For IPPs, being listed is necessary to get a government guarantee/endorsement. The 2018 RUPTL has been revised down by 22 GW (-28%), with renewable capacities dropping 3.7 GW (-17%); only solar (+1 GW) and wind (+0.125 GW) have been revised up.

Figure 2.15 ASEAN cumulative renewable capacity, 2017 and 2023



Viet Nam's renewable capacity is forecast to grow 25%, or almost 4.5 GW over 2018-23. Overall, the forecast has been revised up for solar PV and wind owing to regulatory improvements, and for bioenergy because of increased clarity on future project developments. **Solar PV** is expected to expand by 1.5 GW, supported by the national target, the attractive FIT and the revised regulation governing PPAs for utility-scale projects as well as commercial net-metering. However, extension of the FIT remains a forecast uncertainty for utility-scale PV expansion. **Wind** capacity is expected to grow sevenfold to 1.5 GW by 2023, with nearshore projects providing the majority, driven by the FIT increase. However, the current design of standard PPAs for solar and wind projects remains an impediment to attracting international investors due to perceived bankability concerns over domestic dispute resolution clauses, currency fluctuations and offtaker risks. **Bioenergy** is anticipated to grow 0.5 GW, with three large projects (An Khe, Lee and Man, and Quang Binh) coming online. In addition, smaller projects from provincial biomass development plans contribute to deployment.

Table 2.5 Asia-Pacific: Main drivers and challenges of renewable electricity deployment

Country	Drivers	Challenges
India	Robust and supportive policy environment with ambitious targets and auctions; improved financial status of distribution companies; increased capacity for auctions in solar parks.	Grid expansion and connection delays; uncertainty over pace of solar auction implementation; poor financial health of DISCOMs; challenged project economics under potential safeguard duties.
Japan	Improved auction scheme for large-scale solar PV; continued attractive FIT scheme; energy diversification needs.	High cost of renewables; continued uncertainty over PV project cancellations; lack of grid connection; lengthy permitting for wind and geothermal projects.
ASEAN	New targets, policies, regulations and incentives; progress towards streamlined permitting.	Lack of access to financing; unavailability of land; elevated technology costs; risk perception over project lifetime due to regulatory and policy uncertainty.

In the **Philippines,** renewable capacity is expected to expand 57% (4 GW) over the forecast period, led by hydropower (1.6 GW) and followed by solar PV (1.1 GW), wind (0.7 GW), geothermal (0.37 GW) and bioenergy (0.35 GW). Overall, this year's forecast is more optimistic than last year's owing to new power supply agreements authorised by the energy regulatory commission and announcements from the Philippine Board of Investments for over 1 GW of PV, three biomass and five hydropower projects to be commissioned in 2019-20 (Borneo Post, 2018). At the time of writing, no economic incentives had been provided to support these projects after expiration of the FIT in 2016, but developers aim to receive additional remuneration from the RPS scheme that is planned to begin in 2020. Furthermore, recent news announced a PV project offering a 75-MW PPA to Manila Electric Company (Meralco) for PHP 2.99/kWh (USD 59.7/MWh). While the final contract price is still being negotiated, this rate is roughly 30% lower than the initial natural gas proposal. (Department of Energy Philippines, 2018).

Pakistan's renewable capacity is forecast to rise 65%, or 6.1 GW over 2018-23. Hydropower leads the expansion (3 GW), followed by wind (1.3 GW), solar PV (1.1 GW) and bioenergy (0.7 GW). Renewable energy projects of 3 GW under bilateral contracts were endorsed by concessional financing under the China-Pakistan Economic Corridor. The new auction scheme for wind and solar introduced in 2018 will be a key driver for new deployment. In addition, the net-metering scheme is forecast to induce 80 MW of distributed PV capacity. Bioenergy is anticipated to expand 0.7 GW over 2018-23 through bagasse-fuelled sugar mill co-generation plants, supported through a FIT for electricity exports and low-cost financing. EfW is also supported by a FIT, and one project is included in the forecast. Although the new National Electricity Plan and the new Energy Policy are under discussion, they are not reflected in the forecast. Overall, the country's recent balance-of-payments crisis is expected to increase challenges to accessing renewables financing and presents a key forecast uncertainty.

Asia-Pacific: Accelerated case forecast

In the Asia-Pacific region, the growth of renewable capacity could be 32% or 71 GW higher than in the main case over the forecast period, with solar PV contributing over two thirds and wind one-fifth of additional deployment (Table 2.6). India accounts for over half of the additional regional growth, followed by Japan (15%), Korea (11%), ASEAN countries and Australia (7% each).

In **India**, another 36.6 GW of solar PV capacity could be added, with distributed PV contributing two-thirds, assuming improved net-metering design and higher adoption of PV for public buildings. Faster deployment of utility-scale PV and wind projects depends on the pace of auctions, commissioning of projects, grid connections and improved grid integration. Improving the financial health of DISCOMs would also facilitate faster procurement of solar PV and wind, and minimise the risk of lengthy contract negotiations. Bioenergy could contribute another 2.1 GW of capacity through a dedicated bioenergy mission, improved financing for the sugar industry to increase bagasse co-generation capacity, and more widespread waste management frameworks in cities to support EfW deployment. Hydropower deployment could expand 2.2 GW with faster implementation of large projects currently under development, while small-scale hydro projects would benefit from more streamlined approval processes to ensure project lead times fall within the eligibility window to obtain central financial assistance (Mercom, 2017).

Table 2.6 Asia-Pacific: Main and accelerated case forecast summary, 2017 and 2023

Total capacity (GW)	India			Japan			ASEAN			Asia-Pacific		
	2017	2023 Main	2023 Acc.	2017	2023 Main	2023 Acc.	2017	2023 Main	2023 Acc.	2017	2023 Main	2023 Acc.
Hydropower	48.4	57.7	59.8	50.1	50.9	50.9	41.0	47.0	48.0	188.3	216.9	220.1
Bioenergy	9.3	11.4	13.5	3.6	6.2	7.3	7.2	9.6	10.4	24.6	34.3	39.1
Onshore wind	32.8	65.4	70.4	3.5	6.6	7.2	1.2	3.6	3.8	45.8	93.6	106.4
Offshore wind	-	-	-	0.1	0.8	1.0	0.1	0.9	0.9	0.2	5.5	6.9
Solar PV	19.0	82.0	109.3	49.0	70.3	79.1	4.2	12.7	15.5	88.0	219.5	268.0
CSP	0.2	0.2	0.2	-	-	-	0.0	0.0	0.0	0.2	0.4	0.4
Geothermal	-	-	-	0.5	0.6	0.6	3.7	5.3	5.8	5.2	7.0	7.5
Marine	-	-	-	-	-	-	0.0	0.0	0.0	0.3	0.3	0.3
Total	**109.8**	**216.6**	**253.3**	**106.7**	**135.3**	**146.0**	**57.3**	**79.1**	**84.4**	**352.5**	**577.6**	**648.6**

Notes: Acc. = accelerated. Rounding may cause non-zero data to appear as "0" or "-0"; actual zero-digit data are denoted as "-".

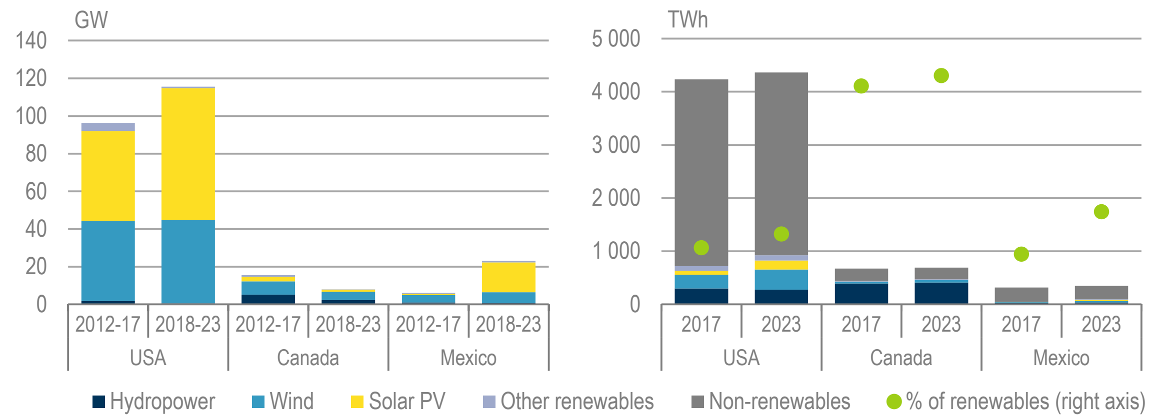
Japan's solar market could expand an additional 11 GW, with accelerated growth dependent on fewer solar PV project cancellations (30% instead of 50% in the main case) under the new FIT regulation. Improved grid integration is also crucial to achieve high deployment of wind and solar PV. Bioenergy could also grow an additional 1.1 GW if robust fuel supply chains are available to biomass developers and higher levels of project financing are secured. Accelerated growth in **Australia** is estimated at 5.2 GW if additional projects (2.6 GW of utility-scale PV and 1.5 GW of wind) get accredited for the LRET, and if distributed PV expands more quickly owing to the economic attractiveness of self-consumption.

In the **ASEAN** region, renewable capacity expansion could be 5.3 GW higher with additional growth in Thailand (2.4 GW), Indonesia (1.5 GW) and Viet Nam (1.0 GW). **Thailand** could add 1.8 GW more of solar PV if the pace of tendering for smart net-metering is accelerated and third-party PPA regulations are clarified. In addition, bioenergy capacity could expand, especially in southern Thailand, by an extra 0.5 GW with enhanced community engagement for bioenergy and EfW projects, and strong uptake through the hybrid FIT scheme. Geothermal additions in **Indonesia** could be 400 MW higher with faster exploration of commercial resources and better access to financing through the geothermal risk mitigation facility. Accelerated capacity growth in **Viet Nam** will rely on extension of the solar FIT, faster implementation of approved projects, and lower risk perception to attract international investors. This could be achieved either by gaining experience through ongoing domestically financed project developments, or through additional regulatory changes and streamlined permitting processes. If the Bac Ai PSH project progresses more quickly, the first phase could be commissioned at the end of the forecast period.

North America

North America's renewable capacity is forecast to expand 39%, to 528 GW over the forecast period, with the greatest expansions in solar PV and wind while bioenergy and hydropower contributing smaller additions (Figure 2.16). The overall forecast for the region has been revised down, as the outlook for the United States is less optimistic due to federal tax reforms and recent trade and energy policy changes. Canada's renewable growth is decelerating, with fewer planned hydropower projects and some project cancellations in Ontario. In Mexico, energy auctions encourage an optimistic doubling of renewable capacity over the forecast period.

Figure 2.16 North America: Renewable electricity capacity growth, 2012-23 (left), and generation by source, 2017-23 (right)



United States: Main case forecast

In the United States, cumulative renewable capacity is forecast to increase 44% (116 GW) over 2018-23, with the share of renewables in total electricity output growing from 17% in 2017 to 21% in 2023. Multi-year federal tax credits, state-level RPSs and technology-specific incentives, and growing corporate renewable energy procurement remain key drivers for US renewables expansion. However, the forecast has been revised down by a slight 6% (7 GW) from last year, mainly because of a federal corporate tax reform and recent changes to trade and energy policies. The tax reform, import tariffs on solar PV modules and steel, and absence of the CPP are anticipated to reduce the economic attractiveness of new wind and solar projects. With this downward revision, the United States shows the third-largest growth market for wind and solar globally, after China and the European Union.

The impact of federal policy changes on the renewables forecast

Federal investment and production tax credits have played a key role in driving deployment of wind and solar technologies in the past decade. In December 2017, the US senate passed the corporate tax reform, which has reduced the maximum corporate tax rate from 35% to 21%. Multi-year federal tax credits for renewables, approved in 2016, were unaffected by the new tax law, but several changes in the tax bill will have implications for renewables financing:

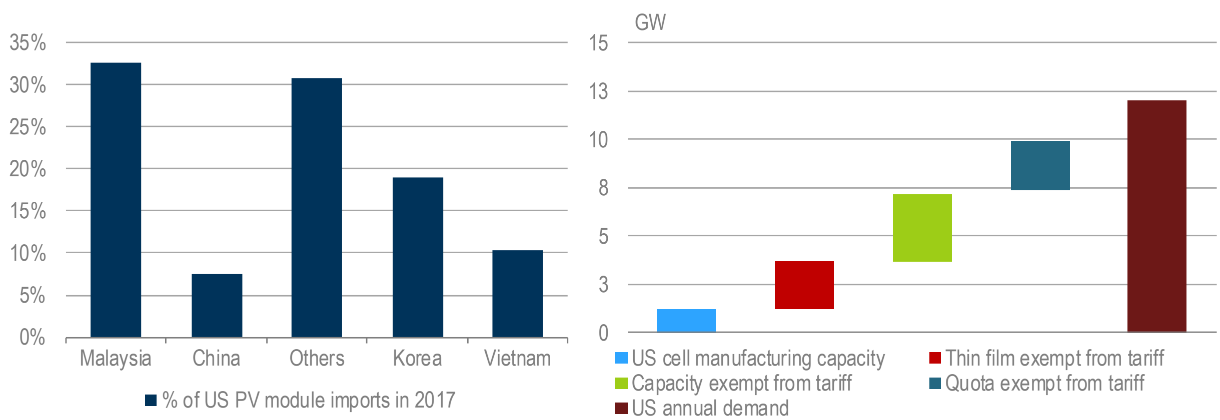
- **Corporate tax reduction from 35% to 21%:** The profitability of existing renewable energy projects will increase with the lower corporate tax, while the situation is more complicated for new projects. The reform means that US companies will pay significantly less tax, which is expected to reduce the size of the tax equity market: in essence, tax equity investors will have fewer liabilities to be offset by tax credits and depreciation. This may reduce the number of tax equity investors, especially for medium-sized investors. As most wind and solar technology developers benefit from tax equity to finance their projects, a smaller tax equity market may mean higher financing costs for some developers as they may need to find additional financing, which could be more expensive.

- **Base Erosion Anti-Abuse Tax (BEAT):** The BEAT is a new minimum tax aimed at preventing large multinational companies from reducing their US tax liability by claiming deductions for payments made to their foreign affiliates. The BEAT applies if 10% of cross-border payment amounts exceed the company's regular US tax liability. Although the BEAT is not designed for renewables tax credits, up to 80% of the value of renewable tax credits can be used against the BEAT tax through 2025, and the rest must be given back to the government. The BEAT is more challenging for production tax credit (PTC) deals because it is claimed over ten years, while the investment tax credit (ITC) can be monetised in one year.

- **100% Bonus Depreciation:** Companies are allowed to deduct the full cost of new or used equipment put into service after September 2017 and before January 2023. Previous rules gave renewables projects 50% depreciation on new equipment in order to increase the value of tax credits. Although the decision to use full depreciation under the new law will be project-specific, a higher depreciation rate may be too large a deduction for tax equity investors. The impact on renewable energy projects is expected to be rather limited.

Recent developments in US trade policy are anticipated to have negative implications for renewables deployment, especially solar PV, over the forecast period. In 2017, the United States imported over 90% of its PV module demand, mainly from Asia (Figure 2.17).

Figure 2.17 United States: PV module import shipments by country in 2017 (left) and PV capacity available to US market after PV import tariff, end of 2017 (right)



In January 2018, the US administration decided to impose import tariffs to crystalline solar cells and modules – set at 30% in 2018 and decreasing to 25% in 2019, 20% in 2020 and 15% in 2021. However, the tariff has three important exemptions:

- Every year, 2.5 GW worth of imports are not subject to the import tariff.
- Thin-film modules, which represent only 3% of global manufacturing capacity (2.5 GW outside of the United States), are exempt from the import tariff.
- Imports from developing countries and some emerging economies (Brazil, India, Singapore and Turkey) with module manufacturing capacity of 3.5 GW to 4.5 GW are exempt.

The tariff is expected to raise the investment cost of solar PV projects by 4-11% (depending on the applications size) in the short term, negatively affecting their economic attractiveness. At the end of 2017, US PV module manufacturing capacity was 1.2 GW, while the annual demand over 2018-22 is expected to range from 10 GW to 13 GW under the main case forecast. Emerging economies exempt from the tariff are all net module importers except Singapore. Thus, module exports from these countries may be limited, but manufacturers also have an incentive to quote relatively higher prices; it is also anticipated that US manufacturers will add a price premium on their products. Furthermore, the 25% tariff duty on imported steel and 10% on aluminium introduced in June 2018 may raise the investment costs of renewables projects, mainly wind, as steel can represent 10-20% of total wind project costs.

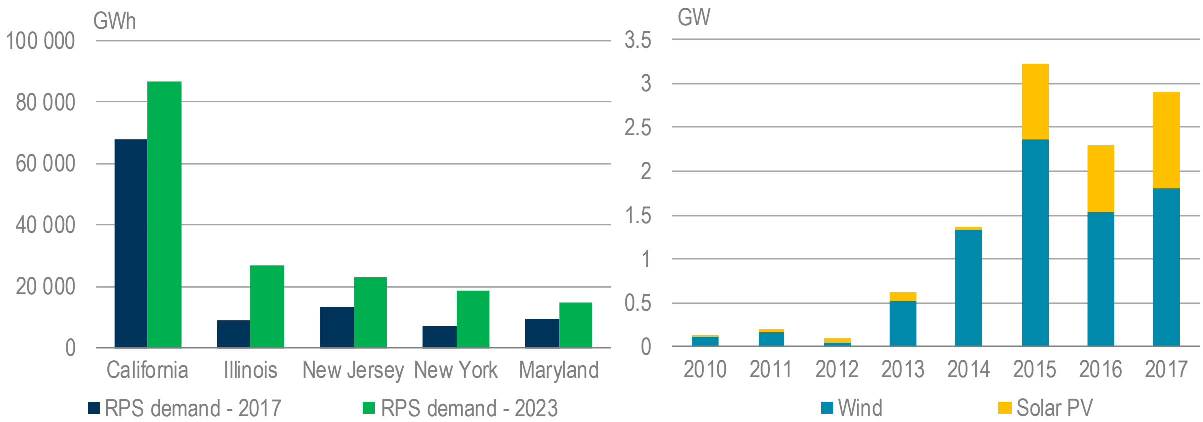
In June 2018, the US administration decided to replace the CPP, which had been designed by the previous administration to introduce CO_2 emissions standards for power plants. The CPP was considered one of the stimulants for wind and solar deployment after the phase-out of federal tax credits in 2020, especially in states where renewable energy deployment was limited. However, the impact of the CPP repeal is expected to be limited during the forecast period, especially in states where renewables policies and targets are strong.

Can individual states and the private sector continue to propel renewable energy deployment?

While federal tax credits remain the most important impetus for wind and solar expansion, state RPS policies will continue to be important. RPSs have been responsible for half of the increase in renewables-based generation since 2000: in August 2018, 29 of 50 states (plus the District of Columbia) had an RPS policy covering almost 60% of US retail electricity sales (LBNL, 2017). In 2017, only New Jersey increased and extended its RPS target from almost 20% in 2021 to 35% in 2025 and 50% in 2030, with a specific solar PV target. While the change in New Jersey is expected to drive additional renewables deployment, California is expected to lead at 16% of total incremental demand from RPSs over 2018-23, followed by Illinois and New York (Figure 2.18). In addition, state-level procurement policies in Massachusetts, New York, New Jersey and Maryland are expected to boost offshore wind expansion. However, in several states where the Public Utility Regulatory Policies Act (PURPA) has been a major driver of renewable energy development (Idaho, Montana and North Carolina), changes to contract length, eligibility and remuneration have been introduced. These changes are expected to reduce PURPA-driven renewable installations over the forecast period.

Corporate procurement of renewables is anticipated to drive additional growth, despite tax reform and solar tariff challenges. In 2017, corporate PPAs grew almost 20% as a result of continuous cost reductions in wind and solar technologies as well as falling REC prices within the Electric Reliability Council of Texas (ERCOT) and the PJM Interconnection. However, the impact of tax reforms and solar tariffs on the corporate PPA market remains a forecast uncertainty as companies are still expected to reassess costs and benefits.

Figure 2.18 United States: RPS demand by state, 2017 and 2023 (left), and announced corporate PPAs, 2010-17 (right)

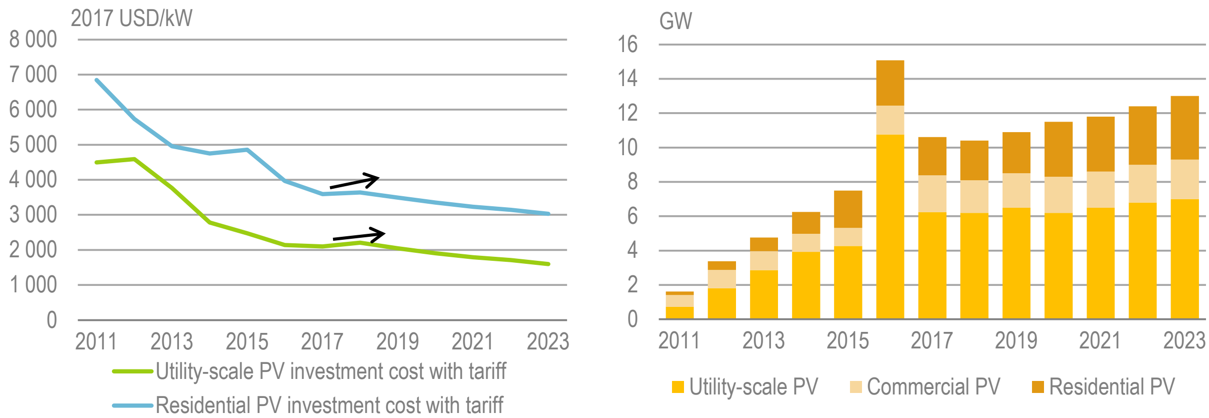


Source: LBNL (2017), *U.S. Renewables Portfolio Standards: 2017 Annual Status Report.*

Solar PV accounts for over 61% of US renewable capacity growth over 2018-23 expanding by 70 GW. However, this forecast has been revised down 4% compared with last year, mainly as a result of the recent federal policy changes. Import tariffs on modules and steel are expected to raise project costs at the same time as the corporate tax reform increases financing challenges.

In 2017, US solar PV capacity additions declined for the first time since 2008, by 30% y-o-y as a result of the developer rush to complete projects before the multi-year extension of the ITC in 2016 (Figure 2.19). Policy uncertainty surrounding the tax reform and solar PV import tariffs in the second half of 2017 has delayed the financial closure of some solar deals, but developers have time to reassess and finalise deals, and start construction by the end of 2019 to be eligible for the full ITC (30%) before it tapers down to 26% in 2020 and 22% in 2021. Utility-scale projects still represent almost 60% of total PV growth in the main case forecast, but they are expected to be more adversely affected by the solar and steel import tariffs than distributed PV projects. Average investment costs for utility-scale projects could increase 7% in 2018 from 2017 as a result of the 30% import tariff on solar modules and higher prices quoted by both local and international manufacturers exempt from tariffs as observed in the second half of 2017. With the reduction of import tariffs over 2019-21 and lower than expected module prices from reduced demand in China resulting in a global oversupply, investment costs should continue to decline. This is anticipated to support more cost-effective deployment. According to the ITC schedule, all qualified utility-scale projects should come online by the end of 2023, leading to increasing capacity additions towards the end of the forecast period.

Figure 2.19 United States: estimated PV investment costs with import tariff (left) and PV net capacity additions, 2011-23 (right)



Source: Historical average solar PV investment costs based on IRENA (2018b), *Renewable Cost Database* dataset provided to the IEA.

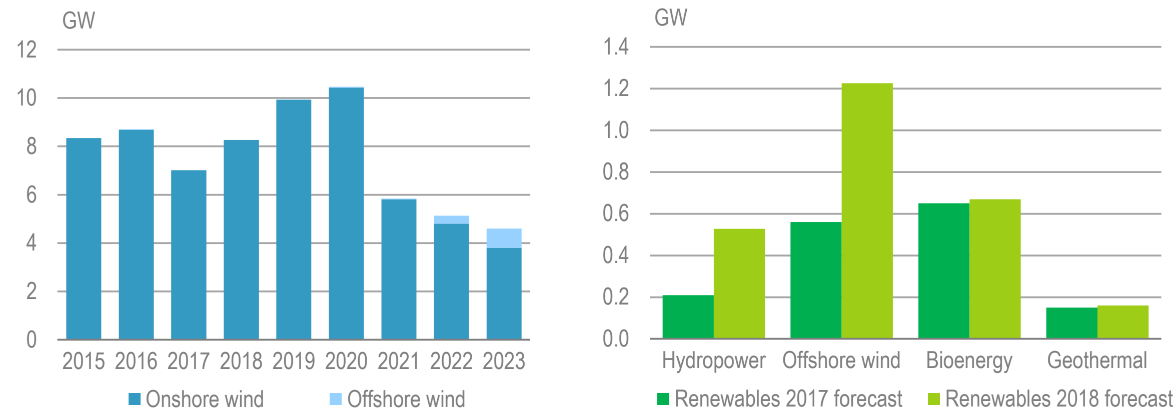
For distributed applications, the price effect of import tariffs could be a 4% increase for residential projects and 6% for commercial ones, as modules represent only 15-20% of total investment costs (Figure 2.19). Overall, the capacity of commercial and residential applications is forecast to more than double with 31 GW coming online over 2018-23. The annual residential market shrank 16% in 2017 due to slowdowns in California, New York and New Jersey after net-metering policy changes in many states and continual customer acquisition challenges that pushed major solar companies to focus on profitability rather than expansion. The new regulation in California requiring all new buildings of three stories or less to have solar panels installed as of 2020 is anticipated to boost that state's residential PV growth by 0.5 GW to 0.8 GW per year. However, the smooth implementation of this regulation depends on the outcome of potential legal proceedings. Outside of California, Utah, Texas and South Carolina are expected to be new growth markets, but sale volumes are expected to rise slowly over the forecast period as residential solar companies adjust to new market conditions after the tax reform and import tariffs.

Conversely, the trend for commercial PV installations was opposite that of residential applications in 2017, showing almost 30% y-o-y growth owing to community solar installations in Minnesota and rushed installations in New York, California and Massachusetts to lock in more favourable incentives. Annual installations are expected to fall in the short term and gain speed again after 2020 as cost reductions and growing demand from state solar carve-outs raise the economic attractiveness of commercial PV technology. For the moment, however, continuous policy and regulatory updates concerning tariff design and remuneration mechanisms in many states create key forecast uncertainties for distributed PV growth.

Onshore wind is forecast to expand 43 GW over 2018-23, accounting for almost 40% of US renewable expansion thanks to PTCs, increasing economic attractiveness in many states and growing RPS demand. However, the onshore wind forecast has been revised down 10% from last year due to recent corporate tax reform changes that have increased financing challenges in the short term, and also to the absence of the CPP after phase-out of the PTC. In 2017, onshore wind capacity additions declined for the second year in row, by 19% to 7 GW, as PTC-qualified developers have time to complete their projects by 2020. As a result, annual additions are expected to peak in 2020 and slow significantly afterwards in the absence of federal incentives – despite decreasing costs (Figure 2.20).

While Texas leads onshore wind growth, New Mexico and Wyoming present new growth markets in which transmission capacity does not pose a challenge in the short term.

Figure 2.20 United States: Net wind capacity additions, 2015-23 (left), and five-year forecast for other renewables (right)



Other renewable technologies are expected to expand a modest 2 GW over 2018-23, led by offshore wind, bioenergy, and hydropower, with smaller contributions from geothermal. Despite the cancellation of the Cape Wind project, **offshore wind** growth is more optimistic than last year driven by the approval of Vineyard and Deepwater expansion projects. The forecast for **bioenergy** is stable, as its capacity increases 5% (670 MW). Deployment is composed of a mix of forestry biomass, EfW, landfill gas and industrial projects. However, although 270 MW of new capacity was delivered in 2017, lower annual additions are forecast over 2018-23 because only plants for which construction began prior to 2018 are eligible for the PTC. **Geothermal** deployment also benefitted from the federal tax credit renewal, but long project lead and construction times have hampered higher upward forecast revisions for both technologies. No additional growth is expected from **CSP** because of relatively high generation costs compared with solar PV and wind, and due to less favourable financing from the US Department of Energy (DoE) Section 1705 loan programme, which applies only to projects for which construction began before 2012.

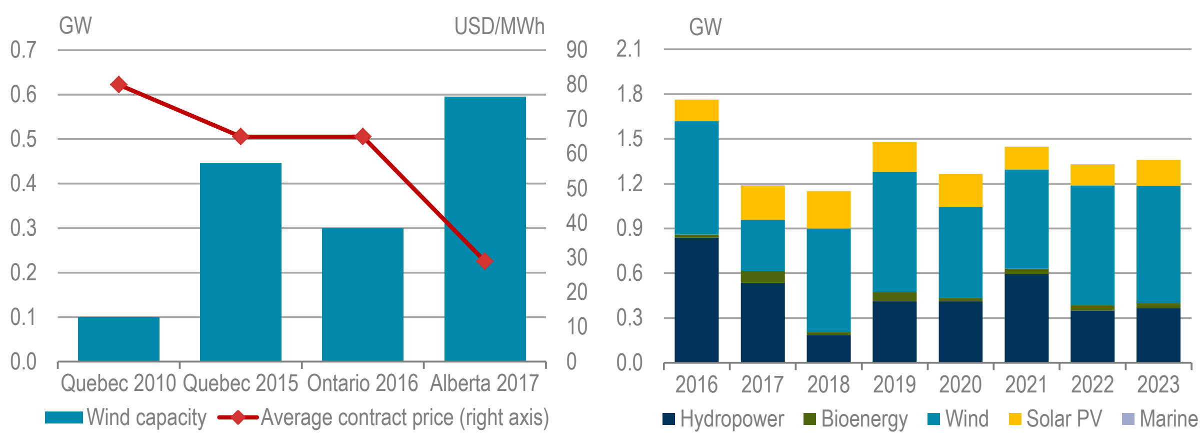
Canada: Main case forecast

Canada's renewable capacity is forecast to expand 8 GW (8%), mainly owing to provincial incentive schemes and auctions in Alberta, Ontario, Quebec and Saskatchewan (Figure 2.21, right). Onshore wind accounts for half of Canada's renewable capacity growth, followed by hydropower, solar PV and bioenergy. The forecast has been revised down from last year due to fewer planned wind projects in Ontario and Quebec, despite additional and cost-effective growth expected in Alberta and Saskatchewan. In addition, the solar PV forecast is less optimistic because wind technology dominated Alberta auctions and policies to boost large-scale capacity expansion remain limited in other provinces. Canada's renewable energy fleet is expected to generate 475 TWh by 2023, 7% more than in 2017, providing almost 69% of overall electricity output thanks to hydropower.

Onshore wind capacity is expected to increase by one-third, or 4.4 GW, but this forecast has been revised down slightly following Ontario's suspension of the Large-Scale Renewable Energy Programme (LRP) and the cancellation of existing contracts under the LRP and FIT (around 150 MW). In addition, Quebec's long-term energy plan published in July 2017 did not include capacity expansion plans. Still, Quebec and Ontario are expected to lead onshore new-builds in the short term with the commissioning of previously contracted projects. Alberta's annual deployment, driven by tenders, should be the largest after 2019. In December 2017, Alberta awarded 595 MW of wind capacity, with bids ranging from CAD 31/MWh to CAD 43/MWh (USD 24/MWh to USD 34/MWh) for an overall average price of CAD 37/MWh (USD 29/MWh) for 20 years. This average price is 57% below the recent Ontario wind tender held in 2016 and the Quebec tender awarded in 2015 (Figure 2.21, left).

Hydropower capacity is expected to increase 3% or 2.3 GW, with the forecast revised up 5% from last year to account for partial commissioning by 2023 of British Columbia's Site C plant, in addition to four large-scale plants (Romaine, Muskrat Falls, Keeyask and the John Hart uprate) expected to be fully operational. The **bioenergy** forecast has been revised down, however, with capacity growth of 200 MW anticipated. Although two large projects delivered a combined 80 MW in 2017, a similar scale projects development is not evident during the forecast period. Biomass co-generation projects in areas without access to natural gas also contribute to the forecast. **Solar PV** capacity is expected to expand 39% to reach 4 GW, but this forecast has also been revised down because solar PV did not win the projects in Alberta's recent tender anticipated in last year's report. With the absence of the utility-scale projects cancelled in Ontario (280 MW), growth will be driven mainly by the commissioning of commercial and residential projects that received approval from Ontario's micro-FIT programme, which was also cancelled in December 2017. Moreover, small municipal and provincial incentive schemes will support installations in other provinces.

Figure 2.21 Canada: Provincial wind auction results (left) and net renewable capacity additions, 2016-23 (right)

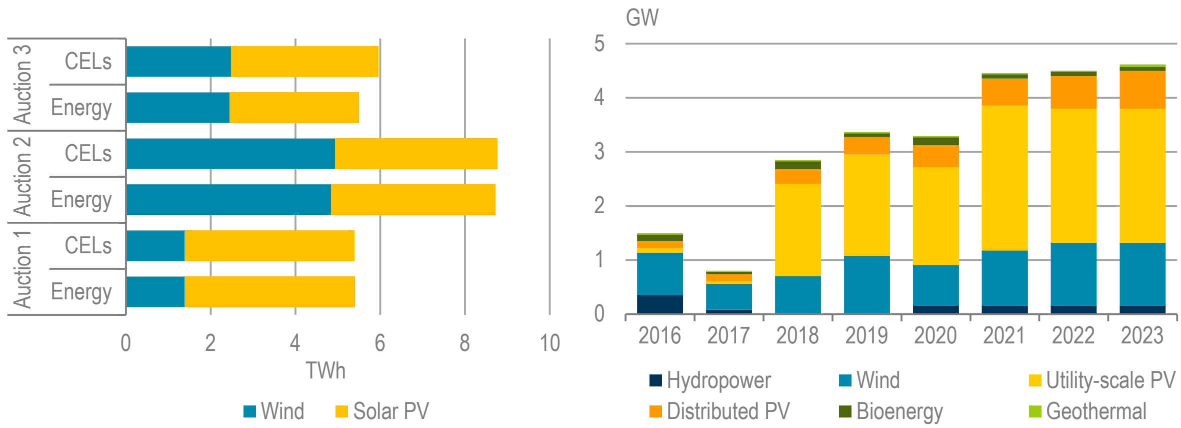


Mexico: Main case forecast

Solar PV leads renewable capacity growth, accounting for two-thirds of Mexico's renewable energy expansion (16 GW) over 2018-23 (Figure 2.22, right). Utility-scale projects are expected to dominate growth (80%) stimulated by energy auctions. The government already contracted 11 TWh in three auctions (Figure 2.22, left), which corresponds to 5.5 GW capacity to be commissioned over 2018-20. However, it is expected that some winning projects will face financing and grid connection challenges. Average contract prices declined from USD 45/MWh in March 2016 to USD 20/MWh in October 2017 due to strong competition that made margins narrower, and because some projects are located in states with weak grid infrastructure.

In the third energy and clean energy certificate (CEL) auction, a new bidding trend emerged with solar PV developers bidding 13% less energy compared with CELs. This means they expect to sell surplus electricity either to the market or through bilateral PPAs at higher prices to increase profitability. Thus, the actual total remuneration of winning PV projects may be higher than that announced. In addition, the recent market reform that enables generators to sign direct PPAs with large consumers is expected to provide some growth outside the auction scheme.

Figure 2.22 Mexico: CEL and energy auction results for wind and solar PV (left) and net renewable capacity additions, 2016-23 (right)



New opportunities are also emerging for the distributed PV market, which is currently nascent with less than 380 MW installed in 2017. High electricity prices for commercial users and additional tax for some residential consumers remain important drivers of distributed generation capacity growth of almost 3 GW in the next five years, supported by net-metering and net-billing policies introduced in 2017.

Onshore wind capacity is expected to more than double, with 5.9 GW expected over the forecast period, although the forecast has been revised down from last year because solar PV has continued to win the majority of CELs in the auctions, despite wind developers offering bid prices that were 10% lower on average than for PV (USD 19/MWh) in the third auction. Still, this year's forecast anticipates that the share of wind developers' contracts awarded in auctions will increase slightly, even though grid integration and affordable financing are expected to remain significant challenges, especially if aggressive bidding continues.

Mexico's **bioenergy** sector is growing, with an additional 0.6 GW of capacity anticipated over 2018-23. Deployment is principally composed of bagasse plants linked to the sugar industry, mainly in Veracruz and Jalisco. However, the potential of EfW generation from municipal solid waste (MSW), sewage gas and landfill gas projects is starting to be exploited, with one large-scale (130 MW) project under development in Mexico City. **Hydropower** is expected to expand 0.6 GW with the completion of projects under development, while **geothermal** is anticipated to contribute smaller additions (150 MW) thanks to the improved permitting structure.

Table 2.7 North America: Main drivers and challenges of renewable electricity deployment

Country	Drivers	Challenges
United States	Multi-year federal tax credits; state-level RPSs and incentives; growing corporate PPAs; improving economic attractiveness of onshore wind and solar.	Corporate tax reform and import tariffs on PV modules, steel and aluminium; absence of the CPP; state-level debates over net energy metering.
Canada	Competitive tenders in Alberta and support for distributed solar PV in several other provinces.	Reduced auction capacity in Quebec and Ontario; cancellation of renewable energy contacts in Ontario; limited provincial support for bioenergy projects.
Mexico	Clean energy target to 2024; regular clean certificate auctions; regulation allowing bilateral PPAs, net metering and billing for distributed generation.	Lower margins of wining projects; weak grid infrastructure in some states; high cost of local financing.

North America: Accelerated case forecast

Overall renewable capacity growth in North America could be 20% higher over the forecast period, with solar PV and onshore wind accounting for over 90% of this additional growth (Table 2.8).

In the **United States**, renewable capacity growth could be 22 GW higher, but the absence of the CPP and tax credits beyond 2020-21 restricts the realisation of this upside potential. The accelerated case assumes that the impact of the tax reform on the tax equity market remains limited, without additional increased capital costs reducing the economic attractiveness of renewable energy projects. For utility-scale solar PV and onshore wind projects, a greater number of projects qualifying for federal tax incentives before they are phased out will be necessary to achieve accelerated deployment. Faster growth of corporate PPAs for new utility-scale renewables could also result in faster deployment of wind and solar PV, especially after 2020. For residential and commercial solar PV applications, additional deployment will mostly depend on timely and smooth implementation of California regulations, and on the robust growth of new housing construction between 2020 and 2023. Faster reduction of the balance of system costs and improvements in state-level policies would also make the accelerated case for distributed PV more likely. For bioenergy, the most probable sources of increased deployment are EfW and pulp and paper projects.

In **Mexico**, the accelerated case for utility-scale wind and solar projects assumes that all auctioned projects secure financing on time and become operational without cancellation or delay. In addition, the accelerate case assumes that more new wind and solar capacity outside of the auction scheme comes online, supported by bilateral power purchase contracts with large consumers or retailers. Bioenergy capacity could be 235 MW higher with more planned EfW co-generation and landfill gas projects, as well as initiatives to increase the efficiency of bagasse co-generation at sugar mills. In **Canada**, solar PV and wind represent the majority of additional accelerated case potential, with an extra 1.4 GW depending on the pace of Alberta's renewables auctions and how quickly awarded projects are commissioned. For bioenergy, the accelerated case takes into account the conversion of one coal plant to biomass in Alberta, following two similar projects in Ontario.

Table 2.8 North America: Main and accelerated case forecast summary, 2017 and 2023

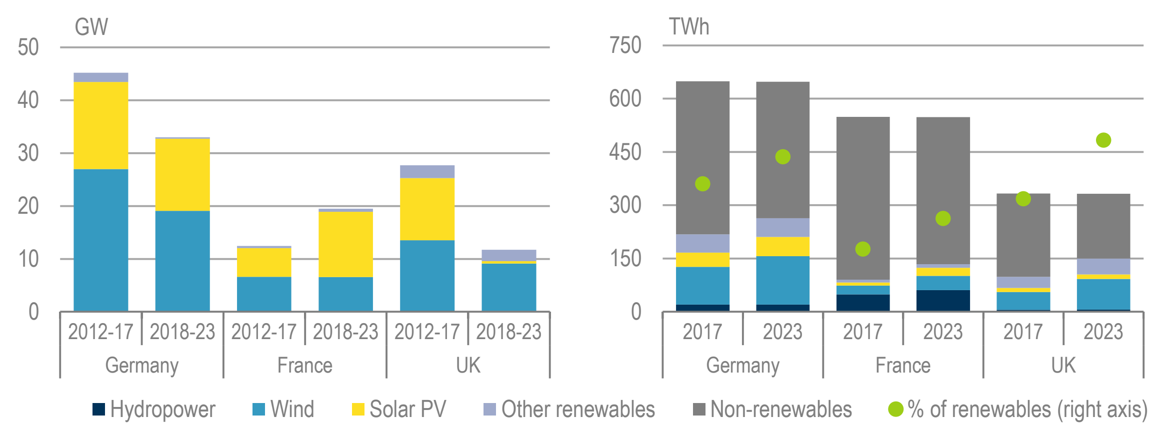
Total capacity (GW)	United States			Canada			Mexico			North America		
	2017	2023 Main	2023 Acc.	2017	2023 Main	2023 Acc.	2017	2023 Main	2023 Acc.	2017	2023 Main	2023 Acc.
Hydropower	102.8	103.3	103.6	80.8	83.1	83.5	12.7	13.3	13.7	196.2	199.7	200.8
Bioenergy	14.3	15.0	15.4	2.6	2.8	3.2	0.9	1.5	1.7	17.7	19.2	20.3
Onshore wind	88.3	131.3	140.9	12.3	16.7	17.4	4.5	10.4	11.8	105.1	158.4	170.2
Offshore wind	0.0	1.3	2.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.3	2.1
Solar PV	52.0	122.0	132.6	2.9	4.0	4.7	0.6	16.4	19.5	55.5	142.5	156.9
CSP	1.8	1.8	1.8	0.0	0.0	0.0	0.0	0.0	-	1.8	1.8	1.8
Geothermal	3.6	3.7	3.7	0.0	0.0	-	0.9	1.1	1.1	4.5	4.8	4.8
Marine	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-	0.0	0.0	0.0
Total	**262.7**	**378.3**	**400.1**	**98.6**	**106.6**	**108.8**	**19.6**	**42.7**	**47.9**	**380.9**	**527.6**	**556.8**

Note: Rounding may cause non-zero data to appear as “0” or “-0”; actual zero-digit data are denoted as “-”.

Europe

Europe’s renewable capacity is forecast to grow by one-quarter (144 GW) over 2018-23, driven by supportive policy environments to reach longer-term climate goals and continued cost reductions, mainly for solar PV and wind technologies. Overall, the forecast has been revised up from last year to reflect recent policy changes aimed at meeting 2020 targets, and because country level targets for 2030 are anticipated to be more ambitious. However, growth is still almost one-fifth lower than over the previous six-year period. Wind accounts for almost half of the renewable capacity expansion (68 GW), mostly from onshore installations, followed by solar PV (59 GW), which is evenly spread between utility-scale projects driven by auctions and distributed applications prompted by increasingly economically attractive self-consumption (Figure 2.23). Bioenergy and hydropower add 8 GW each, with most bioenergy growth stimulated by policy support and led by large-scale plants in the United Kingdom, and co-generation and biogas technologies in the Netherlands. Turkey and Norway are anticipated to host half of the hydropower growth, while another third is from PSH plants in Switzerland, Portugal, Austria and the United Kingdom.

Figure 2.23 Europe: Renewable electricity capacity growth, 2012-23 (left), and generation by source, 2017 and 2023 (right)



Almost half of Europe's renewable capacity growth is expected to happen in three countries: Germany (33 GW), France (19 GW), and the United Kingdom (12 GW). Annual deployment is expected to be volatile in the near term from developer rushes before FIT/FIP support expires, since most European markets have transitioned from administratively set tariffs to competitive auctions. Fluctuations in annual deployment are also expected from the piloting of new auction design rules, which has caused peaks and lulls in project pipelines. By 2019, auctions with fixed budgets or volume caps will largely guide the pace of annual deployment. Additional growth is also expected to emerge from the corporate PPA market, particularly in the United Kingdom, the Iberian Peninsula and Nordic countries.

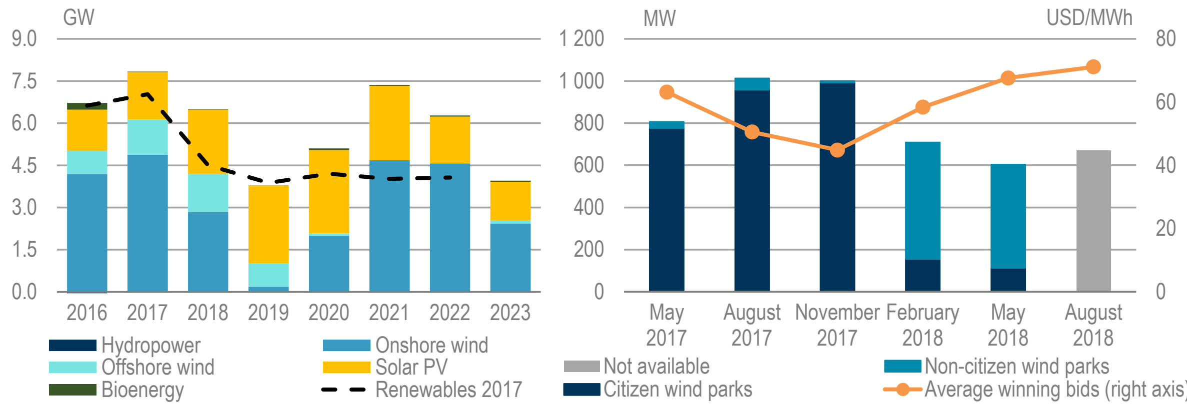
The more optimistic forecast for Europe is due to a surge in auction activity in several countries, notably France, Germany and Spain in order meet 2020 renewable energy targets. Upwards revisions also stem from the expectation that the pace and magnitude of auctions in the European Union will continue beyond current plans because leaders agreed to increase the bloc's renewable energy consumption by 2030. In June 2018, the European Commission, Parliament and Council agreed to an EU-binding renewable energy target of at least 32% by 2030, with a possible increase in 2023 when the target is reviewed. This is an increase relative to the 27% originally proposed and the 20% currently in place for 2020. Yet despite clarity at the regional level, policy uncertainty remains regarding national-level contributions to the overall EU-wide target. Clarity will emerge gradually over the next 18 months when member states present their draft national energy and climate action plans before the end of 2018 and finalise them by the end of 2019. It is unclear how these will be reconciled with any pre-existing 2030 plans in place by member states, although it is expected that in some cases they will be revised upwards.

Germany: Main case forecast

Germany's renewable capacity is expected to increase just over one-quarter (33 GW) over 2018-23, almost entirely from wind and solar PV additions as a result of policies aimed at reaching long-term climate goals. This year's forecast is more optimistic than last year's in anticipation of the government increasing annual auction volumes for solar PV and onshore wind to accelerate deployment to meet longer-term goals. Onshore wind leads the growth (17 GW), though deployment is likely to be volatile as support regimes transition from administratively set tariffs to competitive auctions (Figure 2.24, left). Furthermore, uncertainty over repowering rates and permitting constraints pose downside risks to net annual capacity growth. Distributed systems account for 60% of solar PV growth, led by commercial systems, while auctions continue to guide the pace of utility-scale PV deployment. Overall, grid constraints remain a challenge to renewable energy deployment in Germany.

In 2018, a new proposal to auction an additional 4 GW each of solar PV and onshore wind in 2018-19 was announced in a coalition agreement between two parties following the 2017 elections (CDU, CSU and SPD, 2018). These plans are still under discussion, however, and there is uncertainty over whether the grid can integrate the entire 8 GW over the proposed time interval. In light of these developments, this forecast assumes that at least half of the proposed capacity (2 GW each of solar PV and onshore wind) will be auctioned and commissioned over the forecast period.

Figure 2.24 Germany: Annual net renewable capacity additions, 2016-23 (left), and average winning bids from onshore wind auctions (right)



Source: Federal Network Agency (2018), "Tenders for renewable and CHP plants".

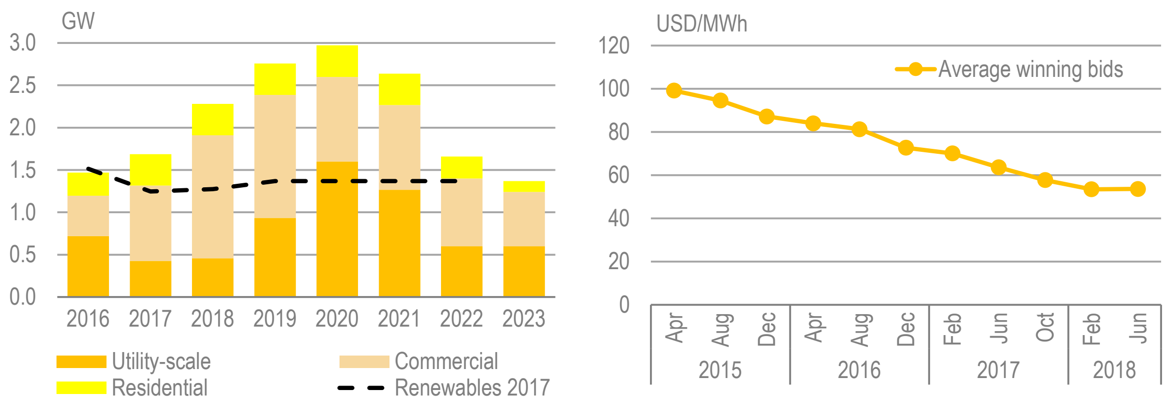
Onshore wind is forecast to grow 17 GW over 2018-23, though annual deployment is expected to be volatile due to the transition from FIPs to auctions: there were record-level net additions (4.9 GW) in 2017 as developers rushed to obtain support under the expiring FIPs before the first auctions began. Residual projects qualifying under the FIP will drive most of the deployment in 2018, albeit at a lower level. Yet by 2019, annual growth is forecast to slow significantly due to an expected lull in the project pipeline from the long commissioning deadlines granted to citizen wind projects,[6] which won 97% (2.7 GW) of the capacity auctioned in 2017. The first three auctions in 2017 allowed citizen wind parks 54 months to commission projects; lower financial guarantees; permission to bid without costly environmental permits; and the right to receive the clearing price (instead of bidding price). As a result of these favourable bidding rules, citizen wind parks were able to place lower bids than other developers (as low as 45 USD/MWh) (Figure 2.24, right). This forecast assumes that most citizen projects will take advantage of the longer deadline and commission over the 2020-22 period, adding to the capacity commissioned from later auctions and driving a rebound in annual growth post-2020. However, the realisation rate for citizen parks remains a forecast uncertainty given that environmental permits still need to be obtained for some projects.

In addition, the impacts of repowering older turbines and permitting constraints on net annual additions are emerging as forecast uncertainties. Roughly 10 GW of capacity will reach the end of its support lifetime during 2020-23, prompting developers to decide whether to enter into the wholesale market, or to dismantle or repower their plants, which have to compete for support against new-build projects in auctions. Furthermore, new-build projects are increasingly encountering permitting challenges, particularly in Bavaria and North Rhine-Westphalia, where new regulations on the minimum distance to dwellings have been introduced, and in Schleswig-Holstein, where there is a moratorium on new permits until the end of September 2018. Combined, these states accounted for almost one-third of new additions in 2017. Such challenges contributed to the fifth onshore wind auction being undersubscribed for the first time (by almost 10%), resulting in a 21% increase in the average winning bid relative to the fourth auction (Figure 2.24, right). Average winning bid prices continued to rise in the fifth auction as a result of permitting challenges.

[6] Projects built as co-operatives, wherein the majority of voting rights are held by local citizens.

Solar PV capacity is forecast to grow 13.7 GW, a significant upward revision from last year's forecast, reflecting additional auctions under the coalition agreement and a more optimistic outlook for commercial systems (Figure 2.25, left). Distributed systems lead the growth at over 60% of total PV additions, impelled mostly by attractive economics for commercial systems under the FIT and FIP schemes. Additions from commercial systems grew more than two-thirds in 2017, and growth continued to accelerate into the first quarter of 2018. Based on these trends, the forecast for commercial systems was revised up under the expectation that the economics remain attractive. However, the impact of future support degressions (triggered by annual capacity growth) on project economics is a forecast uncertainty. By 2020, annual additions for distributed systems are expected to slow due to uncertainty over the new remuneration scheme once the FIT terminates. Over 60% of the distributed growth in 2017 was driven by systems eligible for the FIT, which is set to terminate once the country's national target of 52 GW is met.

Figure 2.25 Germany: Annual net solar PV capacity additions by segment (left) and winning bids from solar PV auctions (right)



Source: Federal Network Agency (2018), "Tenders for renewable and CHP plants".

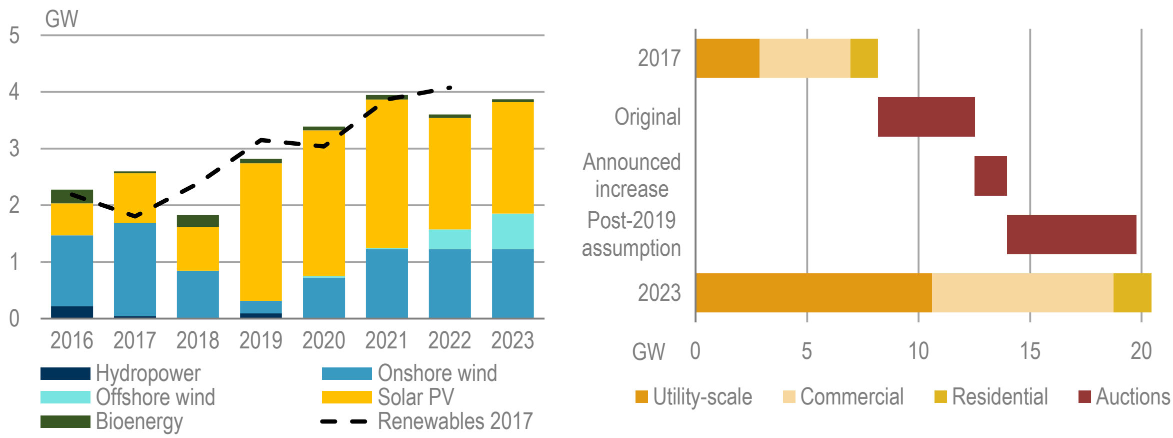
Utility-scale projects account for 40% of Germany's PV growth solely from competitive auctions, which have been driving cost reductions since their introduction in 2015. Over the last three years, the weighted average of winning bids has fallen by almost half from USD 99/MWh (EUR 92/MWh) to USD 53.5/MWh (EUR 43.3/MWh) by February 2018 (Figure 2.25, right). The forecast assumes additional auctions from the coalition agreement will boost utility-scale additions between 2019 and 2020, after which deployment returns to the EEG (Renewable Energy Sources Act) auction schedule.

Offshore wind is expected to grow 2.5 GW over the forecast period, with annual additions from projects under the FIP in the near term, followed by a lull in project pipeline until 2023 when the first project from Germany's first auction for offshore wind is to be commissioned. A second auction was held in April 2018, in which two zero-subsidy bids were awarded. **Bioenergy** is forecast to expand 200 MW, driven by competitive auctions. New projects will have to compete against existing plants seeking support after their FIT expires. However, the attractiveness of new plants is uncertain given that the first two auctions in 2017 and 2018 were undersubscribed and new plants won only a third of the 100 MW awarded.

France: Main case forecast

France's renewable capacity is expected to grow by almost half (19 GW), led by solar PV (12 GW) and followed by onshore wind (5.5 GW), offshore wind (1 GW) and bioenergy (0.5 GW) (Figure 2.26); the forecast has been revised up since last year because the government increased the capacity for forthcoming solar PV auctions in late 2017. Overall, annual renewable capacity additions are expected to accelerate over the next five years, spurred mostly by competitive auctions for solar PV and wind. However, growth strongly depends on the continuation of auctions beyond 2019, which will be a forecast uncertainty until the end of 2018 when a review of the long-term targets will be completed in the updated multi-annual energy plan (PPE).

Figure 2.26 France: Annual net renewable capacity additions, 2016-23 (left), and solar PV auction schedule vs forecast (right)



Solar PV is forecast to grow 12.3 GW, led by utility-scale installations awarded in competitive auctions. This forecast was revised up from last year after 1.4 GW of additional capacity was added to the auctions planned for 2018-19 for ground-mounted and rooftop systems. The original plans (announced in 2016) targeted 4.3 GW of auctions over 2017-19, but the increase announced in 2017 brought the total to 5.8 GW. This more optimistic forecast also assumes the auction schedule will be extended beyond 2019 to meet the longer-term cumulative capacity target of 18 GW to 20 GW by 2023, outlined in the latest multi-annual energy plan.

Distributed solar PV deployment is expected to account for 37% of solar PV growth over the next five years, stimulated by a variety of support mechanisms including FITs, competitive auctions for FIPs, and schemes that incentivise self-consumption. Most of the deployment is expected to come from commercial systems awarded through competitive auctions for rooftop systems and self-consumption; the introduction of technology-neutral tenders totalling 450 MW over 2017-20 is driving most of the growth for self-consumption. The new framework uses competition to set remuneration levels for excess generation, and a fixed premium is provided for the self-consumed electricity. The first tender was held in 2017, with solar PV winning all 50 MW at an average excess-generation remuneration rate of EUR 7.9/MWh – significantly lower than the previous tariffs of EUR 19/MWh to EUR 41/MWh produced in the 2016. Although this forecast assumes solar PV will continue to win the majority of capacity, the attractiveness of the scheme is emerging as a forecast uncertainty: only 2 MW of 50 MW were awarded in the second round due to speculation over whether third-party business models were exempt from the renewables levy on retail bills, raising questions about project bankability. However, a new law permitting projects that group multiple customers within a 1-kilometre (km) radius for self-consumption also supports the forecast.

Onshore wind capacity grows 5.5 GW in this year's forecast, mostly from the recently introduced competitive auctions. France's first onshore wind auction was held in December 2017 for 500 MW, and the weighted average winning price was EUR 65.4/MWh. However, cumulative capacity is forecast to reach just under 19 GW by 2023 – falling short of the 21 GW to 26 GW targeted – due to uncertainty over the impact of permitting challenges on project development timelines. In September 2018, the country's second onshore wind auction was undersubscribed by 75% mainly due to permitting delays. Additional deployment outside of auctions can come from residual projects from the expired FIP or from small projects of less than 18 MW that are still eligible for the FIP. Long project lead times have been a major challenge to these projects due to complex administrative procedures, permitting delays and local opposition. Recent trends indicate these barriers could be lifting. In 2017, record-level onshore wind growth was reached (1.6 GW), due in part to the new single permitting procedure (introduced in 2014 to reduce complex approval procedures), which created a developer rush to lock in support in advance of the auctions. Furthermore, a newly created National Wind Working Party tasked with accelerating onshore wind deployment introduced plans to reduce litigation and simplify regulations in early 2018.

Offshore wind is expected to expand 1 GW by 2023 – revised down from last year's forecast because tariff negotiations from the first auctions have delayed 3 GW of project development. Recent European competitive auctions resulting in prices of EUR 50/MWh to EUR 75/MWh prompted the French government to re-evaluate its own offshore wind tariffs of EUR 180/MWh to EUR 230/MWh: the agreed tariff is now 30% lower than originally set. Additional growth is expected from several floating turbines in the near term, following on from the first one of 2 MW commissioned in 2018. **Bioenergy** is anticipated to grow 550 MW, with deployment supported by auctions for co-generation and biogas systems. The first two auctions combined delivered around 120 MW of capacity, and a third auction is planned for 2018. In addition, the 150-MW Provence 4 coal-to-biomass conversion is to come online in 2018. An additional 100 MW of **hydropower** is forecast to be operational by 2023, from a mix of small hydropower plants.

United Kingdom: Main case forecast

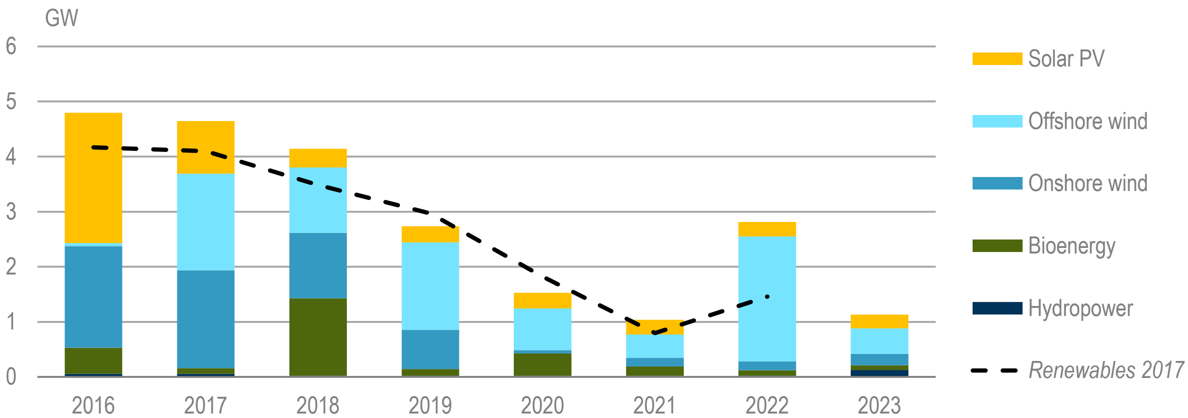
Renewable electricity capacity in the United Kingdom is expected to increase by 27% or 11.7 GW over 2018-23, a slight downward revision on last year's forecast (Figure 2.27). Annual renewable capacity additions are expected to fall from 2018 onwards, reflecting reduced renewable electricity policy support since 2015, as the current UK government prioritises limiting the additional costs of renewable energy subsidies on consumer bills.

From now on, the consumer cost of policy support for low-carbon electricity will be subject to the Control for Low Carbon Levies mechanism. Once existing policy commitments are fulfilled, it is unlikely under the new control that further renewable electricity policy support that would result in levies on consumer bills will be permitted up to 2025. This may, however, be reassessed if generation costs fall in a sustained manner.

Consequently, the forecast rests mainly on projects supported by the 2015 and 2017 Contract for Difference (CfD) auctions for 15-year power purchase contracts, which provide 60% of forecast capacity additions. New renewable capacity is also delivered from "grace period" projects that are eligible for accreditation under the Renewables Obligation (RO) certificate scheme until early 2019.

The RO scheme was closed to new applications in March 2017, and new renewable capacity from grace-period projects will be far lower than that delivered prior to the scheme's closure.

Figure 2.27 United Kingdom: Annual net renewable capacity additions, 2016-23



In addition, deployment of solar PV, wind, hydro and biogas technologies below 5 MW through the FIT scheme has fallen as a result of lower tariff payments and the introduction of deployment caps. The UK government is currently consulting on whether to close the FIT programme to new applications as of March 2019. The *Renewables 2018* forecast assumes that the FIT scheme closes as of then; however, this represents a forecast uncertainty.

Offshore wind is expected to account for just over half (6.7 GW) of net additions to renewable capacity over the next five years. While offshore wind capacity was delivered through both the CfD and RO schemes in 2017, projects supported by the CfD scheme drive deployment in the future. As a result, forecast capacity additions vary according to the year in which auctions were held, and half of capacity growth is expected to happen in 2019 and 2022. Results from the 2017 CfD auction indicated a 50% cost reduction for new offshore wind compared with the 2015 tender.

Onshore wind capacity is expected to grow 2.3 GW, with over three-quarters of new capacity forecast to be commissioned by 2020 as a result of RO grace period projects and capacity awarded in the 2015 CfD auction. Annual additions are far lower thereafter due to the absence of policy support from these schemes, but some merchant project development, driven by corporate PPAs, is anticipated towards the end of the forecast period. Most future onshore wind deployment is expected to be in Scotland because of its good wind resources. In addition, onshore wind development on Scottish islands more than 10 km from the UK mainland will be eligible to compete in the next CfD auction, scheduled for 2019.

Bioenergy capacity is anticipated to grow 2.1 GW by 2023. Major projects in the forecast include a 420-MW coal-to-biomass conversion and a 299-MW electric co-generation plant, both of which have been awarded CfD support and are under construction. In addition, a fourth 645-MW coal-fired unit at the United Kingdom's largest power station was converted to biomass in 2018. In the 2017 CfD auction, a cap of 150 MW was applied to biomass projects. Therefore, while biomass co-generation and technologies based on the gasification and pyrolysis of biomass fuels should be eligible to participate in the 2019 CfD auction, the capacity eligible for contracts may be capped.

In 2017, 860 MW of **solar PV** capacity was delivered, of which almost 500 MW was through RO grace-period projects. With no further RO and CfD support anticipated, and based on the assumption that the FIT scheme closes in 2019, solar PV capacity is anticipated to grow by around 470 MW over the forecast period, less than 5% of deployment compared with the previous six-year period. The best prospects for ongoing deployment are anticipated to be in residential and commercial projects for which the value of self-consumption is high and ratepayers can save on their electricity bills.

Hydropower capacity is anticipated to increase 170 MW with delivery of a 100-MW PSH project, provided it obtains suitable financing, in addition to some deployment of small-scale hydro projects. One **marine** project (5 MW) was deployed in 2017. Although the sector is not expected to receive a ring-fenced (i.e. protected) budget in the 2019 CfD auction, a number of demonstration projects (26 MW) are expected to come online over the forecast period.

Table 2.9 Europe: Main drivers and challenges of renewable electricity deployment

Country	Drivers	Challenges
Germany	Targets combined with support schemes, and predictability from a clear timeline of fixed-volume auctions.	Grid constraints; ageing onshore wind fleet; onshore wind permitting slow-down; self-consumption surcharge for commercial PV.
France	Ambitious targets supported by auctions, with a clear schedule for solar PV and onshore wind until 2019; technology-specific working groups established to accelerate deployment.	Uncertainty over auction design for self-consumption tenders; long development lead times for onshore and offshore wind.
United Kingdom	Strong project pipeline for offshore wind, coupled with CfD policy support; need for investment in new capacity.	Reduced policy support for onshore wind, solar PV and bioenergy; low prospect of further policy support under the Control for Low Carbon Levies mechanism; FIT phase-out proposed for March 2019.

Other countries in Europe: Main case forecast

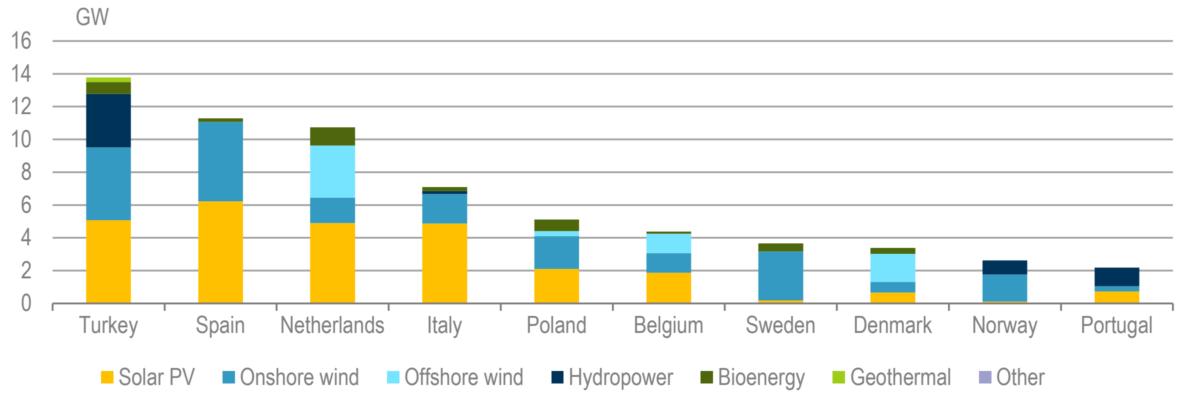
Turkey's renewable capacity is expected to expand 35%, or almost 14 GW over the forecast period, led by onshore wind (4.4 GW), solar PV (5.1 GW), hydropower (3.2 GW), bioenergy (0.7 GW) and geothermal (0.3 GW). Onshore wind forecast has been revised down due to a lull in project development, resulting from the transition from FITs to auctions. Annual onshore wind capacity additions are expected to decelerate in 2018 and 2019 and slowly gain speed again after 2020. For wind capacity, delays in transmission auctions and permitting for projects licensed under the FIT scheme have created a lull in project development; commissioning of these projects should begin in the second quarter of 2019. In addition, the winning project (YEKA) from the first 1-GW wind tender has not yet received financing. It is expected that the YEKA project will be commissioned in 2020-21, while additional tenders scheduled in 2019 and 2020 should support new wind capacity to be commissioned at the end of the forecast period. Although offshore wind development areas had been selected in March 2018 and developers are expected to submit their bids by October 2018, commissioning of the first capacities is not anticipated by 2023.

For solar PV, capacity additions more than quadrupled in 2017 to 2.6 GW, mostly through 'unlicensed' projects, but growth is expected to decline significantly over the forecast period as a result of stricter regulations and increased grid fees that make solar PV technology less economically attractive. Utility-scale projects under the YEKA tendering scheme are anticipated to drive expansion, with the first 1-GW project to come online in the fourth quarter of 2019. As with wind capacity, the YEKA tenders to be held 2019 and 2020 are included in this forecast. For commercial and residential applications, a new self-consumption and remuneration regulation is being drafted, but the final version is not yet available. As a result, this forecast assumes that commercial and residential applications expand after 2020, but amount to 1 GW over 2018-23. Hydropower capacity growth over the forecast period is 68% lower than over the previous six years. Most large-scale projects under construction are expected to be commissioned in 2018, leaving the project pipeline relatively empty during the forecast period. However, generous FITs and good resource availability are driving additional geothermal growth.

Spain's renewable capacity is expected to grow 20% (11 GW), led by solar PV (6 GW) and followed closely by onshore wind (5 GW), contracted mostly through competitive auctions. Over 8 GW of solar PV and wind capacity were auctioned in 2016-17 to meet the country's 2020 renewable energy targets. However, there is uncertainty over the pace of annual deployment, as many projects had yet to reach financial closure by April 2018, which may delay commissioning times (BNEF, 2018a). Nonetheless, Spain's forecast has been revised up significantly from last year because of the increasing economic attractiveness of solar PV outside of auctions from corporate PPAs and self-consumption business models for large consumers. Around 12% of utility-scale growth in Spain over the next six years is expected to be arranged through bilateral contracts with large electricity consumers alone or in combination with wholesale electricity market revenues. This more optimistic forecast is also prompted by higher growth prospects for distributed PV, spurred by expanding self-consumption, which also drove most of the 135 MW of distributed PV growth in 2017 – the highest level since 2013, just after the moratorium on support was introduced.

The **Netherlands**' renewable capacity is anticipated to more than double (26% higher than last year's forecast), expanding by 10.7 GW and led by solar PV growth of 4.9 GW. Success for solar PV in recent rounds of Sustainable Energy Production (SDE+) auctions has been driving utility- and commercial-scale growth, while residential PV is surging thanks to attractive economics under the net-metering scheme – although proposed revision of the scheme after 2020 makes the forecast uncertain. Growth continues under the auction programme for offshore wind (+3.2 GW), onshore wind (+1.6 GW) and bioenergy (+1.1 GW).The bioenergy forecast has been revised up as a result of high 2017 deployment (670 MW), indicating that a higher share of capacity awarded from previous SDE+ auctions can be delivered. Key technology types are biomass co-generation and biogas: several major biomass co-firing projects at existing coal plants were awarded subsidies under the SDE+ scheme and are expected to deliver 7 TWh of generation annually by 2020.

Figure 2.28 Net renewable capacity growth in selected countries in Europe, 2018-23



Italy's renewable capacity is forecast to grow 13% or 7.1 GW over 2018-23, mostly in solar PV (4.9 GW) and followed by onshore wind (1.8 GW). This forecast has been revised up from last year based on the draft of the new energy decree, which is to be adopted in late 2018 and proposes seven rounds of auctions for 5.5 GW and FITs for 0.8 GW of additional renewable capacity over 2018-20. The new auctions will be held for three technology categories: 1) wind and solar 2) bioenergy, geothermal and hydropower and 3) repowering. Because solar PV is economically attractive, this forecast expects it to win the majority of capacity auctioned in the first category. In addition, solar PV for commercial and residential applications is expected to continue growing 2.9 GW over the forecast period, mainly in installations for self-consumption and driven by the new FIT/FIP[7] registry mechanism. Onshore wind grows supported by the registry incentive scheme and auctions for repowering. Bioenergy deployment of 240 MW, especially from landfill gas, is expected under the auction and registry scheme, followed by 180 MW of hydropower. After 2020, deployment is expected to be increasingly driven by the improving economic attractiveness of solar PV and wind, owing to bilateral contracts and (semi-) merchant plants.

Renewable energy capacity in **Belgium** is expected to grow by almost half (4.4 GW), led by wind (2.4 GW) and solar PV (1.9 GW). The existing green certificate scheme, net-metering and federal auctions are anticipated to drive this expansion but the visibility over these schemes is a forecast uncertainty. In late 2017, regional governments agreed to a new energy pact with a higher 2030 national target. However, local governments still need to develop their individual strategies and decide on accompanying support schemes. This forecast assumes the current incentives in each region continue. After the failure of two projects in 2017 under the previous regional plans, only a handful of smaller bioenergy projects are expected to come online before the end of 2023.

Denmark's renewable capacity is forecast to grow 3.4 GW over 2018-23, primarily in offshore wind (1.7 GW), solar PV (0.7 GW) and onshore wind (0.6 GW), mostly contracted through competitive tenders after expiration of the FIPs. Two technology-neutral auctions have been announced for 2018 and 2019, and three 800-MW offshore wind farms are to be tendered starting in 2021 (with commissioning beyond the forecast period). Bioenergy in Denmark is anticipated to increase 370 MW, owing to coal-to-biomass conversions at co-generation plants.

Sweden is anticipated to have renewable capacity expansion of 13% (3.7 GW), the bulk of it from onshore wind (3 GW), including three projects with corporate PPAs over 800 MW. Bioenergy is

[7] FITs for plants of up to 100 kW of capacity and FIPs for plants of up to 1 MW.

expected to grow almost 500 MW over the forecast period, mostly from biomass- and waste-fuelled co-generation plants to serve industry or municipal district heating schemes. Distributed PV (residential and commercial) is forecast to add almost 200 MW, funded by an increased budget allocated specifically to capital grants for rooftop installations.

Solar PV (+2.1 GW), onshore wind (+2.1 GW) and bioenergy (+0.7 GW) lead renewable capacity expansion of just over 5.1 GW in **Poland**. The overall forecast is more optimistic than 2017 expectations owing to the 2018 amendment of the Renewable Energy Act, the unlocking of the auction system for renewables and the removal of high taxes for onshore wind projects. Most new capacity is set to come online from planned 2018 and 2019 auction rounds and the net-metering scheme.

Europe: Accelerated case forecast

Europe's renewable capacity growth in the accelerated case is almost one-third higher than under the main case (187 GW versus 144 GW) (Table 2.10). Solar PV and wind account for the majority of extra growth (88%), followed by equal contributions from bioenergy and hydropower. Most additional solar PV and wind capacity results from increased auction activity in Germany, France, Spain, Italy and the Netherlands. In some markets, plans to hold additional auctions were announced to accelerate deployment to meet near-term targets where progress is lacking. The accelerated case assumes that these plans are fully implemented, and that all capacity is online by 2023. In other markets, the accelerated case assumes that governments continue to hold additional auctions beyond the currently planned ones to meet longer-term climate goals. Overall, better network interconnections would also facilitate accelerated growth, particularly for VRE.

Table 2.10 Europe: Main and accelerated case forecast summary, 2017 and 2023

Total capacity (GW)	Germany			France			United Kingdom			Europe		
	2017	2023 Main	2023 Acc.	2017	2023 Main	2023 Acc.	2017	2023 Main	2023 Acc.	2017	2023 Main	2023 Acc.
Hydropower	11.3	11.3	11.9	25.6	25.7	25.9	4.6	4.8	4.8	231.0	239.2	242.2
Bioenergy	9.6	9.8	10.5	1.8	2.3	2.6	5.9	8.0	8.6	41.7	49.9	52.9
Onshore wind	50.4	67.0	71.8	13.1	18.6	22.8	13.0	15.3	15.9	161.1	212.7	227.8
Offshore wind	5.4	7.7	10.3	0.0	1.0	1.5	6.9	13.6	13.6	15.9	32.7	36.7
Solar PV	42.4	56.1	61.3	8.2	20.5	23.8	12.8	13.2	13.2	112.1	171.2	189.1
CSP	0.0	0.0	0.0	0.0	0.0	0.0	-	-	-	2.3	2.3	2.3
Geothermal	0.0	0.1	0.1	0.0	0.0	0.0	-	-	-	2.6	3.0	3.1
Marine	-	-	-	0.2	0.2	0.2	0.0	0.0	0.0	0.2	0.3	0.3
Total	119.1	152.1	165.9	48.9	68.4	76.9	43.2	54.9	56.2	566.9	711.4	754.4

Note: Rounding may cause non-zero data to appear as "0" or "-0"; actual zero-digit data are denoted as "-".

The largest portion of additional growth in Europe's accelerated case comes from solar PV, for which capacity could be 18 GW higher than in the main case, with almost equal growth potential for both utility-scale and distributed projects. For utility-scale, the accelerated case assumes that Germany's coalition agreement is implemented in full, that France continues to hold ground-mounted and rooftop tenders beyond 2019, and that Italy's recently planned auctions are won by a majority of solar PV. It is also assumed that additional growth results from bilateral contracts and merchant plants in Spain, as the costs of some projects have become competitive with the wholesale electricity market. Boosting the economic attractiveness of self-consumption and continued FIT support for smaller systems underpin the growth potential for distributed systems throughout Europe.

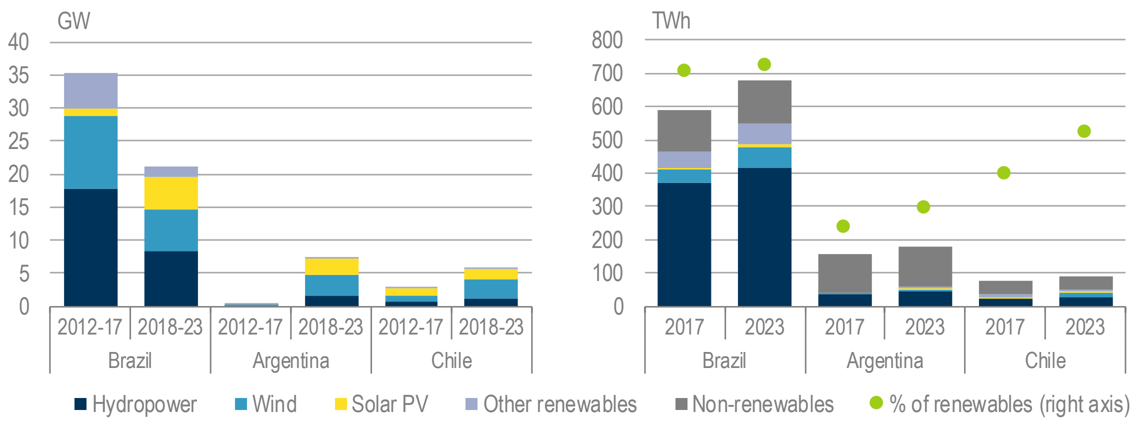
Onshore wind could be 15 GW higher with greater auction activity and faster auction implementation in Germany, France, Spain and Italy. Increased deployment from projects outside of auctions is expected for smaller wind projects still eligible for FITs/FIPs in France and corporate PPAs in Sweden, Spain and the United Kingdom. The accelerated case also assumes no significant decommissioning of wind projects in major markets, along with faster permitting and quicker network expansion. Faster project development and network connections would also enable an additional 4 GW of offshore wind.

Prospects for bioenergy also improve under the accelerated case with potential for another 3 GW of capacity, mainly from higher deployment of coal-to-biomass conversion projects and EfW projects in Denmark and the United Kingdom, as well as more competitive projects in Germany's biomass tenders. Given that most of Europe's economically attractive hydropower sites have been exploited, the accelerated case is limited to Turkey's untapped large hydropower potential and to additional PSH development in Austria, Germany, Spain and France. Combined this equates to an additional 3 GW of capacity. PSH projects have great potential in Europe given the need for power system flexibility to integrate VRE, but adequate support schemes, streamlined and less-costly permitting procedures, and remuneration for ancillary grid services for PSH plants are needed for higher deployment.

Latin America

In Latin America, renewable capacity is forecast to grow one-quarter, or 50 GW over 2018-23. Hydropower (18 GW) and wind (16 GW) each provide one-third of this expansion, followed by solar PV (13 GW) and bioenergy (2.7 GW). Renewable energy auctions for wind, solar PV and bioenergy drive the forecast increases, with prices comparable with or lower than for fossil fuel alternatives. Wind and solar PV forecasts are more optimistic, mainly owing to additional rounds of auctions in Argentina, while hydropower growth declines in the region as large-scale project development in Brazil remains limited after commissioning of the Belo Monte plant (Figure 2.29, left). In Chile, the share of renewables in total generation rises by a third over the forecast period, to 60% by 2023, driven by growing generation from hydropower, onshore wind and solar including CSP.

Figure 2.29 Latin America: Renewable electricity capacity growth, 2012-23 (left), and generation by source, 2017 and 2023 (right)



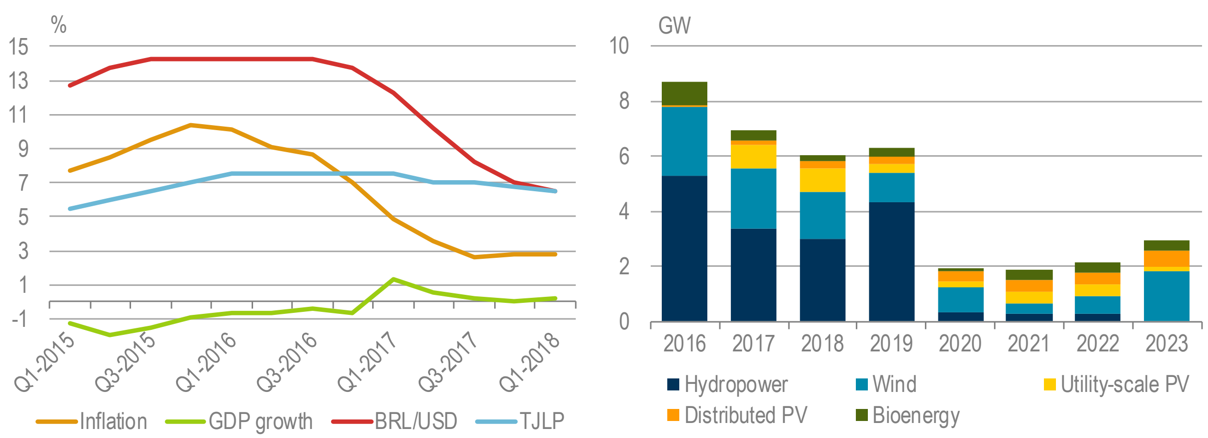
Brazil: Main case forecast

Renewable capacity in Brazil is anticipated to grow 17%, from 128 GW in 2017 to 149 GW in 2023. Hydropower leads renewable expansion (8.3 GW) followed by onshore wind (6.4 GW), solar PV (4.8 GW) and bioenergy (1.7 GW). Overall, the capacity expansion for 2018-23 has been revised down from last year due to less large-scale hydropower project development. Meanwhile, the forecast is more optimistic for solar PV and onshore wind because of macroeconomic improvements and the announcement of new energy auctions. Overall, financing and grid connection remain important challenges to the timely commissioning of renewable energy projects.

Brazil's economic recovery has continued in the past year with further improvements to the main macroeconomic indicators. Whereas Brazil's economy contracted 3.5% in both 2015 and 2016, it grew 1% in 2017 and inflation has fallen to below the central bank's target, raising real revenue and allowing lower interest rates, which is expected to support investment recovery (OECD, 2018) (Figure 2.30). Accordingly, electricity demand grew 1% in 2017, inciting a more positive outlook of 2% electricity generation growth annually over 2018-23 and creating additional opportunities to use renewables in the electricity system. The government awarded 2.4 GW of renewable capacity in 2017, significantly higher than the 0.6 GW in 2016 when energy auctions were suspended and renewable energy contracts were cancelled.

Hydropower capacity is anticipated to increase 8% to reach 109 GW in 2023, with annual additions peaking in 2019 with full commissioning of the Belo Monte and Baixo Iguacu plants; capacity growth then declines significantly in the second half of the forecast period. Increasing environmental concerns, indigenous sensitivity and public acceptance issues have challenged the development of new large-scale hydropower plants, but despite slower growth, hydropower remains the largest source of electricity generation in Brazil (62% of the country's total output in 2023).

Figure 2.30 Brazil: Macroeconomic indicators, 2015-18 (left), and net annual renewable capacity additions, 2016-23 (right)



Note: TJLP = Brazil National Development Bank Long-Term Interest Rate.

Onshore wind capacity is forecast to expand over 6.4 GW, driven by energy auctions supported by the Brazilian National Development Bank's (BNDES) affordable financing. In 2017, wind developers won contracts in both auctions: 1 387 MW of capacity to be commissioned in 2023 at an average price of BRL 96/MWh (USD 30/MWh), and 64 MW to be commissioned in 2021 at an average price of

BRL 108/MWh (USD 33/MWh). These contract prices are 40-45% lower than in the auction held in 2015 because the commissioning dates were extended and developers' price expectations for turbines were lower, since demand for local turbines had been sluggish in the preceding years. In addition, stricter qualification requirements, including a preliminary competition for available transmission capacity, falling local interest rates and the participation of international lenders reduced project risks. This forecast expects that better macroeconomic conditions and new auctions will reduce financing and grid connection challenges, supporting more cost-effective deployment.

The **solar PV** forecast has been revised up to account for falling contract prices after the recent energy auction and emerging distributed generation projects driven by the net-metering scheme. Utility-scale projects from existing and future auctions are expected to make up half of the 4.8 GW of PV expansion expected. For residential and commercial applications, the government has improved financial conditions for project loans, raising the size limit for net-metering projects to 5 MW and exempting panels from the state sales tax. These policies are expected to support growth in distributed generation applications, especially in Minas Gerais, São Paulo and Rio Grande do Sul where retail prices are the highest, improving their economic attractiveness.

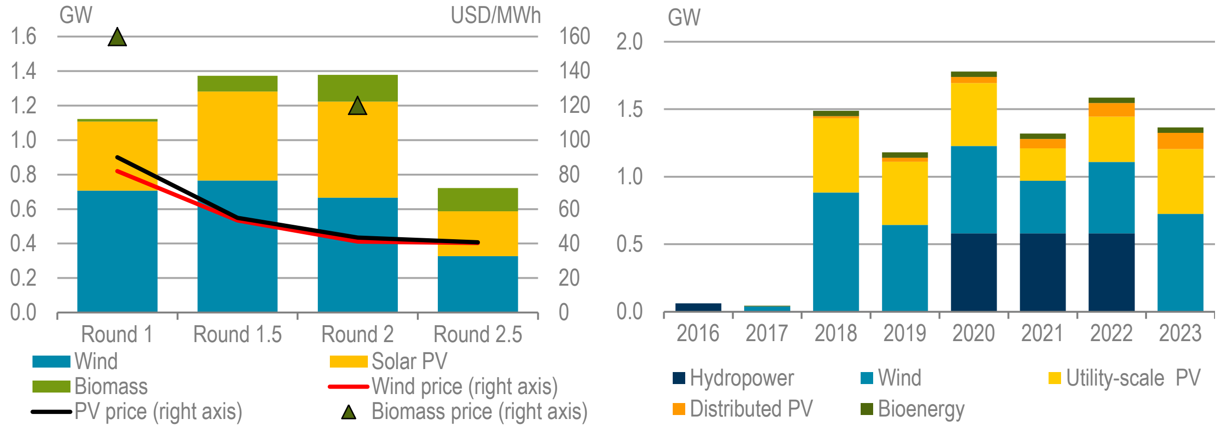
Bioenergy capacity in Brazil is anticipated to expand 1.7 GW, a slight downward revision from last year's forecast resulting from PPA cancellations of several large-scale projects. Project development may also be impeded by the weakness of the Brazilian real against the US dollar, making imported plants and equipment more expensive. However, it is anticipated that the federal RenovaBio plan to boost the production of transport biofuels, due to come into force in 2020, will result in additional bagasse-based electricity generation from both new mills and existing facilities. Other fuels that contribute to the forecast include forestry plantations, black liquor from the pulp and paper industry and biogas.

Argentina: Main case forecast

Renewable capacity in Argentina is expected to increase from 13 GW in 2017 to 22 GW in 2023, mostly spurred by competitive auctions. Wind and solar PV account for almost 80% of renewable capacity additions in the next six years, followed by hydropower and bioenergy (Figure 2.31). Overall, the forecast for Argentina has been revised up because higher-than-expected renewable capacity was contracted in the Round 2 auction and the government approved a new regulation allowing renewable energy developers to sign bilateral PPAs with large customers. However, the fierce competition among developers in the second auction is anticipated to create financing challenges for small-scale developers, despite the involvement of the World Bank and the International Financing Corporation (IFC) offering concessional loans and payment guarantees. In addition, Argentina's macroeconomic challenges remain a key forecast uncertainty, especially after the International Monetary Fund's approval of a USD 50-billion bailout in June 2018.

In the Round 1 and 1.5 auctions, the government awarded over 2.4 GW of renewable capacity, and the World Bank payment guarantee against offtakers' default covered almost half of this capacity. In the Round 2 auction, the country awarded almost 2 GW of additional projects, with average solar and wind prices declining 25-30% (Figure 2.31). Local developers without large balance sheets won the majority of contracts in the second round, raising the question of whether the projects will be financed and built on time. However, with recent macroeconomic developments and delays in grid expansion, the government decided to postpone the third auction, which is reflected in the forecast.

Figure 2.31 Argentina: Renewable energy auction results (left) and net renewable capacity additions, 2016-23 (right)



In August 2017, the Ministry of Energy and Mines published a new regulation enabling large energy users to comply with renewable energy consumption quotas through bilateral PPAs and/or own-use generation in addition to buying power from the national utility (CAMMESA). Accordingly, in early 2018 the government granted dispatch priority for over 270 MW of solar and wind projects for which PPAs had already been signed with large customers. With retail electricity prices rising as electricity subsidies are reduced, the corporate PPA market is expected to become an important stimulus for new project development outside of the auction scheme; in fact, some large-scale consumers have a better credit rating than CAMMESA. If renewable energy developers can sign long-term contracts (15-20 years) with more reliable offtakers, they may decrease their financing costs.

Onshore wind is forecast to expand 3.8 GW over 2018-23, with the majority of growth driven by competitive auctions, while new projects with bilateral PPAs should become more widespread after 2020. Annual capacity additions fluctuate according to auction volumes and commissioning deadlines, and the main case forecast expects commissioning delays for some projects due to financing and grid integration challenges. **Solar PV** is anticipated to grow 2.9 GW, dominated by utility-scale projects, and the share of PV projects that wins bids is expected to increase as technology costs decline further. Commercial and residential applications should slowly emerge over the forecast period with implementation of the net-metering scheme that was introduced in January 2018. The phase-out of electricity subsidies is expected to result in higher retail prices, improving the economic attractiveness of distributed generation projects. The **hydropower** forecast has been revised up from last year to account for full commissioning of the 1.7-GW Jorge Copernic and Presidente Nestor Kirschner projects by 2022, financed by China's Gezhouba Group. **Bioenergy** deployment also grows, with an additional 240 MW anticipated over 2018-23 from auction-awarded projects; this is also an upward revision from last year's forecast.

Chile: Main case forecast

Chile's renewable capacity is expected to grow by 50% or 5 GW over the forecast period, in line with last year's analysis. This expansion is anticipated to be driven by short- and long-term renewable energy targets, technology-neutral competitive auctions and the scheme for small project procurement (under 9 MW). Onshore wind leads growth, followed by hydropower and solar PV. Regarding CSP, all capacity set to come online in Latin America is expected to be commissioned in Chile. Hydropower leads renewables-based generation until 2023, but non-hydropower capacity is set to dominate growth over the forecast period.

In November 2017, Chile awarded 2.2 TWh/year of generation in its technology-neutral energy auction, which was ten times oversubscribed; around 90% of available generation was awarded to renewable energy companies. The weighted average contracted price was USD 32.5/MWh, a 32% decline compared with 2016 and a 60% decline from the 2015 auction. However, most projects are expected to begin delivering power in 2024. Auction winners are permitted to meet their contractual obligations either by building new projects or by sourcing power from already existing power plants. Thus, this forecast expects that the majority of renewable capacity growth over 2018-23 will come from capacity awarded in previous auctions.

Table 2.11 Latin America: Main drivers and challenges of renewable electricity deployment

Country	Drivers	Challenges
Brazil	Improving macroeconomic indicators; energy auctions with long-term PPAs; increased size limit for net metering.	Ongoing investment and currency risk; electricity market overcapacity; grid connection delays.
Argentina	Long-term targets with competitive tenders; concessional financing; new regulation on bilateral PPAs.	High country risk and weak grid infrastructure in some locations; poor offtaker financial health.
Chile	Competitive tenders; agreement between the government and the main utilities not to build any more coal plants without carbon capture and storage.	Financing challenges; increasing curtailment due to delayed grid infrastructure development.

Onshore wind capacity is expected to grow 2.6 GW to reach nearly 4 GW by 2023, based on the 0.4 GW awarded in the 2015 auction and 1.8 GW awarded in 2016, with commissioning set for 2021. **Solar PV** is set to expand by 1 GW to reach 3 GW of total capacity by 2023, with most of the growth coming from utility-scale projects. However, commercial projects are set to expand from 5% of installed PV capacity in 2017 to 10% in 2023, owing to the small distributed generation systems regulation (PMGD: Pequeños Medios de Generación Distribuidos). Chile is expected to commission its first **CSP** projects over the forecast period: the 110-MW Cerro Dominador project in the Atacama Desert reached financial closure in May 2018 and is expected to come online in 2019.

Latin America: Accelerated case

In Latin America, renewable capacity growth could be 15% (7 GW) higher under the accelerated case than in the main case (Table 2.12). In **Brazil**, more rapid improvement of macroeconomic indicators would provide better financing conditions for renewable technologies. A more positive economic outlook in the short term could in turn translate into higher electricity demand over the forecast period and result in additional energy auctions for utility-scale solar PV, onshore wind and bioenergy. For hydropower, the accelerated case requires that planned small hydropower projects be commissioned sooner than projected. Successful implementation of the RenovaBio plan to decarbonise the transport sector would consequently boost bagasse-based electricity capacity.

For **Argentina**, the accelerated case assumes both macroeconomic situation improvement and timely commissioning of new transmission capacity, resulting in a higher number of wind and solar projects under both the auction scheme and through bilateral PPAs. However, increased financing from both multilateral and commercial banks is required to achieve accelerated growth of renewable capacity. In **Chile**, the additional expansion of renewables depends upon timely grid connection of wind and solar projects and faster uptake of distributed PV generation.

Table 2.12 Latin America: Main and accelerated case forecast summary, 2017 and 2023

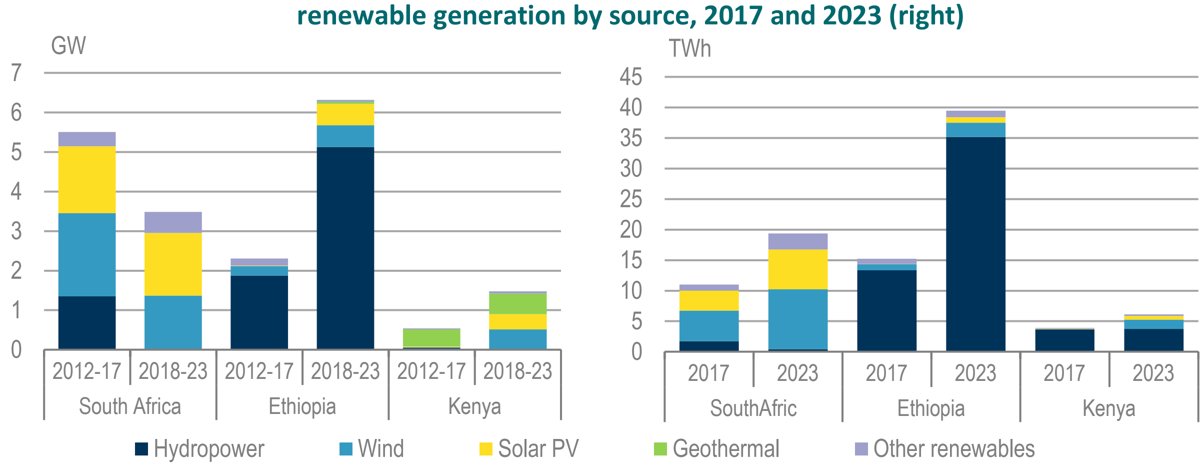
Total capacity (GW)	Brazil			Argentina			Chile			Latin America		
	2017	2023 Main	2023 Acc.	2017	2023 Main	2023 Acc.	2017	2023 Main	2023 Acc.	2017	2023 Main	2023 Acc.
Hydropower	100.3	108.6	109.5	12.5	14.2	14.7	6.8	8.0	8.0	174.4	192.7	194.1
Bioenergy	14.5	16.2	16.8	0.7	0.9	0.9	0.7	0.7	0.7	19.7	22.4	22.9
Onshore wind	12.3	18.7	19.8	0.3	4.1	5.1	1.2	3.8	4.2	17.3	33.3	35.6
Offshore wind	-	-	-	-	-	-	-	-	-	-	-	-
Solar PV	1.1	5.9	6.8	0.0	2.9	4.7	1.8	2.9	3.1	4.8	17.7	20.4
CSP	-	-	-	-	-	-	-	0.1	0.4	-	0.1	0.4
Geothermal	-	-	-	-	-	-	0.1	0.1	0.1	0.7	1.1	1.1
Marine	0.0	0.0	0.0	-	-	-	-	-	-	0.0	0.0	0.0
Total	**128.2**	**149.5**	**152.9**	**13.5**	**22.2**	**25.4**	**10.6**	**15.7**	**16.5**	**217.0**	**267.2**	**274.7**

Note: Rounding may cause non-zero data to appear as “0” or “-0”; actual zero-digit data are denoted as “-”.

Sub-Saharan Africa (SSA)

In SSA, renewable capacity is forecast to grow 70% (27 GW) from a small base during 2018-23, in line with last year’s forecast. Hydropower is expected to lead renewables growth in the region, growing by 12 GW, as Ethiopia alone brings 5 GW of capacity online. However, non-hydropower technologies are anticipated to account for over 50% of all new capacity additions – a new trend in the region (Figure 2.32). Solar PV capacity is forecast to quadruple by 2023, with the majority of additions from utility-scale projects, often contracted through auctions.

Figure 2.32 SSA: Renewable electricity capacity growth, 2012-23 (left), and renewable generation by source, 2017 and 2023 (right)



Source: Historical capacity data based on IEA (2017), *Renewables Information 2017*.

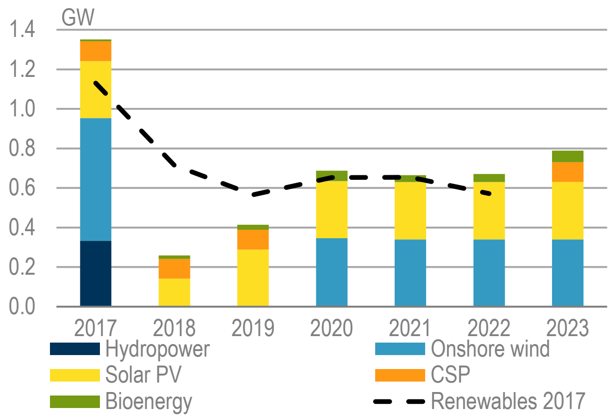
Off-grid PV applications are gaining momentum and are set to contribute 30% of solar technology additions through mini-grids, industrial applications and solar home systems (to bring electricity services to an estimated 30 million people). Wind capacity is expected to more than double, and overall renewables-based generation also almost doubles to 225 TWh.

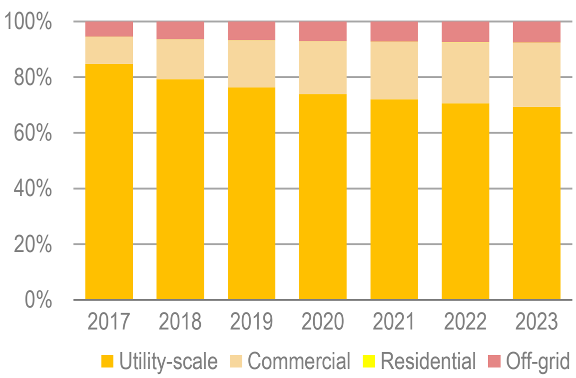
Deployment in the SSA region will be stimulated by intensive electrification efforts, growing power demand and relatively low generation from hydropower plants due to prolonged droughts, as well as by policy measures. However, despite the continent's vast renewable energy potential, growth is constrained by limited access to financing, underdeveloped grids and infrastructure, unstable offtaker financial situations and, in many countries, an uncertain policy environment.

South Africa: Main case forecast

Renewable capacity in South Africa is forecast to grow 40% over the forecast period, from 8 GW in 2017 to nearly 12 GW in 2023. Solar PV leads expansion at almost half of all additions (1.6 GW), followed closely by onshore wind (1.4 GW), CSP (0.3 GW) and bioenergy (0.2 GW) (Figure 2.33). Growth is expected to be driven by competitive auctions under the Renewable Energy Independent Power Producer Procurement Program (REIPPPP) for utility-scale projects, while distributed solar PV is driven by self-consumption and pilot net-metering programs.

Figure 2.33 South Africa: Annual net renewable capacity additions, 2017-23 (left), and solar PV capacity shares by segment (right)





Developments in the past year indicate increased momentum in renewable energy deployment in South Africa, yet grid constraints and policy uncertainty remain key challenges to the pace of future auctions. With the support of the new administration, PPAs were signed in April 2018 for 2.3 GW of stalled capacity awarded under REIPPPP rounds 3.5, 4 and 4.5, after three years of unexpected delay. Shortly after these developments, the government announced plans to hold round 5 for another 1.8 GW, although no auction schedule was announced at the time of writing. While these are positive steps towards maintaining investor confidence, grid constraints remain a barrier to future deployment. The cost of expanding the grid to integrate capacity awarded in previous rounds was one of the main reasons for the delayed PPA signing; this delay has created a lull in project development and lower annual deployment is expected for 2018 and 2019. Additions are expected to recover and remain stable over 2020-23 as rounds 3.5 and 4 are commissioned, but the forecast is cautious about grid's ability to integrate additional capacity from future auction rounds. The country's long-term capacity expansion plan (the Integrated Resource Plan) is currently being updated and the latest draft (released in August 2018) notes that capacity additions from auctions beyond Round 4 must be considered alongside transmission system planning.

South Africa's **solar PV** capacity is expected to double to 3.3 GW by 2023, most of the additions being utility-scale projects contracted through the REIPPPP auctions. However, the share of solar PV installations for commercial purposes is also anticipated to expand from 10% of total PV capacity in 2017 to 23% in 2023, prompted by rising electricity prices and net-metering schemes in major cities that make commercial installations more economically attractive, as well as by the appeal of having a source of pure self-consumption as backup during possible load-shedding. **Off-grid PV** capacity is forecast to triple to 0.3 GW by 2023 from applications in large industries such as mines, and from small solar home systems (SHSs) in the residential sector. Supply uncertainties from Eskom, falling costs of off-grid solutions and greater private sector involvement drive growth in this segment. **Onshore wind** capacity is forecast to grow 1.4 GW, to reach 3.5 GW by the end of the forecast period, pending timely land acquisition and grid connection at the end of the construction phase. Additions are expected to slow in 2018 and 2019, however, due to a lull in project development resulting from a delay in signing 1.3 GW of capacity from REIPPPP rounds 4 and 4.5. Contracts gained through previous auction rounds drive **CSP** capacity additions of 0.3 GW and **bioenergy** of 0.2 GW.

Ethiopia: Main case forecast

Ethiopia's renewable energy capacity is expected to nearly double to 11 GW by 2023, making it the region's leader in renewable capacity growth. Hydropower is forecast to provide 80% of this growth, owing to Ethiopia's excellent resource availability and its strategy to become one of the main power exporters in East Africa. In addition, non-hydropower renewables growth is anticipated to emerge over the forecast period as a result of the government's efforts to diversify the energy mix. Solar PV is forecast to grow 0.5 GW and onshore wind by another 0.5 GW over 2017-23, in line with the *Renewables 2017* forecast but subject to uncertainties concerning timely grid connection and the completion of cross-border transmission lines.

Ethiopia's **hydropower** capacity is expected to double from nearly 4 GW in 2017 to almost 9 GW by 2023, mainly due to completion of the 5-GW Grand Renaissance Dam (GERD) and Genale Dawa III (0.25 GW) plants. The latter was completed in early 2018, while the GERD was reportedly 65% complete and ready for reservoir filling as of June 2018. This forecast expects the GERD to be fully commissioned by 2022, and slowly ramp up its power output by an average 4 TWh annually. Ethiopia's overall hydropower generation is expected to almost triple from 13 TWh in 2017 to 35 TWh in 2023.

Wind capacity is expected more than double to almost 0.9 GW by 2023, driven mostly by the 0.55 GW awarded in the 2016 auction. Recent financing of the 120-MW Aysha II wind project by the Export-Import Bank of China and of the 100-MW Assela wind farm by the Danish encourages a more optimistic outlook for wind capacity. This report therefore assumes that 80% of the capacity auctioned in 2016 will be commissioned within the forecast period, while the rest is expected to face financing, land acquisition and grid connection delays.

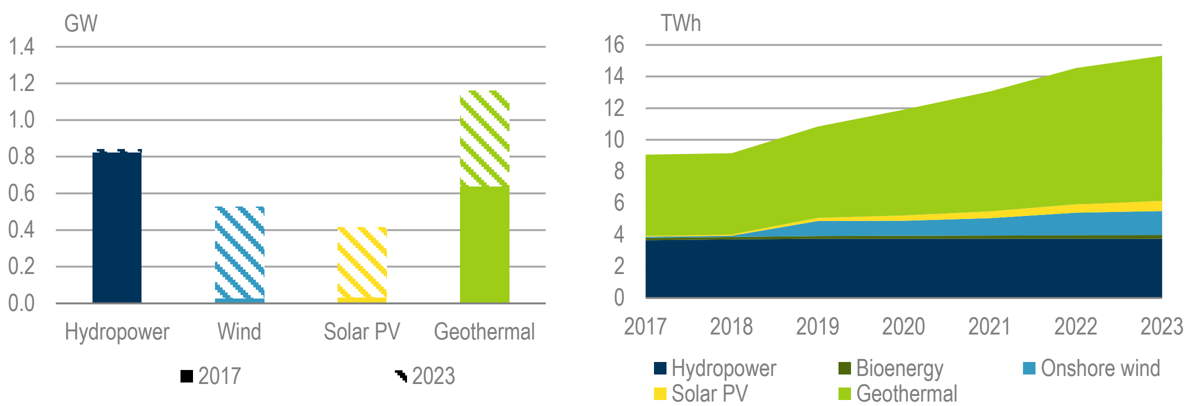
Solar PV capacity is forecast to grow from a very small base of 15 MW in 2017 to nearly 550 MW by 2023 with the commissioning of utility-scale projects from national auctions held in 2016 and from the Scaling Solar[8] ones of 2018. In October 2017, Ethiopian Electric Power (EPP) concluded its first auction, awarding 100 MW of PV capacity to an international consortium, but the price of the 20-year PPA was not disclosed (Enel Green Power, 2017). This project is expected to come online by 2020, accounting for potential administrative and grid connection delays. In October 2017, Ethiopia initiated the Scaling Programme tendering process for 250 MW of solar PV, with auction results expected in late 2018/early 2019 and all capacity to be commissioned in 2023. **Off-grid solar PV** capacity should grow from an estimated 15 MW in 2017 to 80 MW in 2023, driven by the country's ambitious target of universal electricity access by 2025 with the financial support of the World Bank (World Bank, 2018). Growth will be mostly from SHSs for residential electrification and mini-grid developments for public buildings such as hospitals, schools and universities across Ethiopia.

In other renewables, **geothermal** expansion is expected with commissioning of both the 35-MW Aluto Langano extension and the 20-MW Corbetti project, the first capacity growth since 1999. **Bioenergy** capacity grows 50 MW with the Reppie EfW facility, which was commissioned in the summer of 2018.

Kenya: Main case forecast

Kenya's renewable capacity is expected to double, expanding by 1.5 GW over 2018-23. Non-hydropower technologies account for most of the capacity addition, led by geothermal (0.52 GW) and followed by onshore wind (0.5 GW) and solar PV (0.4 GW) (Figure 2.34, left). Growth is propelled by electrification efforts, the strong need for additional power capacity and the availability of long-term FITs. However, offtaker risks, persistent land acquisition problems, grid connection delays and policy uncertainties related to a possible transition from FITs to an auction mechanism remain key forecast uncertainties. Renewable electricity generation is expected to rise by over two-thirds with geothermal accounting for 60% of this growth (Figure 2.34, right).

Figure 2.34 Kenya: Total renewable capacity (left) and generation, 2017 and 2023 (right)



Geothermal capacity is expected to grow 0.5 GW, to reach 1.2 GW in 2023. Excellent resource availability and Kenya's need to diversify generation away from hydropower and thermal plants remain important motivators, and recent financing and project development activity support a more optimistic outlook than last year. In 2019-20, the Olkaria V (158-MW) plant and the

[8] Scaling Solar is a World Bank and International Finance Corporation (IFC) programme to help governments mobilise privately funded grid-connected solar projects at competitive tariffs. The programme brings together a suite of World Bank Group services under one single engagement based on a standardised approach to create viable markets for solar power in each client country.

extension on Olkaria I (70 MW) are expected to be commissioned. Following a five-year delay, drilling is expected to start on the Olkaria VI (140-MW) plant in the second half of 2018, with completion scheduled within the forecast period. In addition, the financial closure for the Menengai plant (35 MW) is expected by the end of 2018. **Wind** capacity in Kenya is to grow 0.5 GW over 2018-23, but onshore wind projects are being delayed by late grid connections and land disputes. After a 1.5-year grid connection delay, the Lake Turkana wind project (310 MW) is expected to start generating power in the second half of 2018.

Solar PV growth of 0.4 GW is anticipated over 2018-23, driven by on-grid projects (just over 80%) supported by 20-year FITs. However, land acquisition problems, weak grid infrastructure, lack of access to affordable financing, and offtaker risks remain key challenges to deployment; in addition, the transition from FITs to an auction system increases policy uncertainty. Despite expectations, no new utility-scale projects were announced or reached the financing stage in 2017. **Off-grid PV** capacity is expected to triple over the forecast period to 90 MW, driven by SHS applications for residential electrification and mini-grids.

Nigeria: Main case forecast

Renewable capacity in Nigeria is anticipated to grow almost threefold to 4.6 GW by 2023, encouraged by renewable energy targets, electrification efforts and the need for new power capacity. Hydropower accounts for 60% (1.5 GW) of the expansion, followed by PV (1.2 GW). However, limited access to affordable financing, the poor financial performance of local distribution companies, policy uncertainty concerning possible renegotiations of signed PPAs and weak grid infrastructure are still key obstacles.

In January 2018, Nigeria adopted the Power Sector Recovery Programme (PSRP) to attain power sector financial viability and to support the Nigerian Electricity Supply Industry (NESI) through policy actions and operational and financial interventions. PSRP is supported by the World Bank, and its implementation is expected to improve power supply reliability, strengthen the power sector's institutional framework, encourage investor confidence and establish a contract-based electricity market. It is possible that these changes will positively impact renewable energy development, but the pace of implementation remains a forecast uncertainty.

Hydropower is expected to expand 1.5 GW as construction of several delayed projects advances, largely owing to financial backing and engineering support from Chinese companies. After decades of planning, the 3-GW Mambilla plant entered the construction phase in November 2017, and commissioning of the plant's first stages is expected by the end of the forecast period. The Zungeru 700-MW hydropower dam also obtained financing, was 50% completed as of early 2018, to be commissioned by 2020. In addition, the Challawa (0.025 GW) and Kashimbila (0.04 GW) dams are to be commissioned within the forecast period.

Nigeria's **solar PV** capacity is expected to be enlarged 1.2 GW, mostly from grid-connected utility-scale projects contracted through 14 PPAs signed in 2016 for 1.1 GW of capacity; however, none of these projects have yet reached financial closure. Overall, offtaker risks, the recent economic recession, land acquisition challenges and grid connection delays remain barriers to financial closure for these projects. In addition, in early 2018 the government expressed interest in contract renegotiations with developers to reduce tariffs from USD 115/MWh to USD 75/MWh. **Off-grid solar PV** is expected to grow 50% to reach 60 MW by 2023 with the uptake of the mini-grids and SHSs; this growth is driven by the ambitious mini-grid targets and policies in place. In fact, the Rural Electrification Agency (REA) aims to establish 10 000 mini-grids across Nigeria by 2023. Twice a year, the REA releases financial support from the Rural Electrification Fund in the form of capital grants for mini-grids and stand-alone systems. Mini-grids smaller than 1 MW are eligible for this support; selected projects can receive the grant, at a value of up to 75% of the total project cost, while the necessary grid extension is eligible for the same level of support. In addition, SHSs can receive capital grants of up to 50% of total project costs.

Tanzania: Main case forecast

Renewable power capacity is expected to grow by 0.2 GW, to reach almost 0.9 GW by 2023. Growth is forecast to be led by solar PV and onshore wind, in response to the strong need for additional power generation. This forecast has been revised down from last year, as various solar PV and wind projects have shown limited progress and no new projects were announced in the past 12 months. In addition, despite adoption of a renewable capacity auction framework in 2017, no auctions have yet been held, and the state-owned utility (Tanesco) is experiencing prolonged financial difficulties. This situation leads to increased offtaker risks, which negatively affects the cost of financing for renewable technologies and makes concessional financing critical. In addition, administrative and regulatory barriers remain key challenges to renewable energy development.

Onshore wind is expected to grow 100 MW with commissioning of the Signida wind farm initiated in 2009, although construction has not yet begun. **Solar PV** growth is anticipated to come from two projects to be developed in Dodoma (55 MW) and Kondo (30 MW). Tanzania has number of **hydropower** projects in development, to be commissioned by 2023, but only one small-scale project (8 MW) has secured financing so far. Growth is driven by independent power producer (IPP) contracts and support from international financial institutions. **Off-grid PV** capacity is projected to double over 2018-23 to reach total capacity of 40 MW, mainly in SHSs and mini-grids as more private companies become involved in developing projects.

Table 2.13 SSA: Main drivers and challenges of renewable electricity deployment

Country	Drivers	Challenges
South Africa	Need for new capacity; supportive policy environment with long-term PPAs; rising power prices.	High costs and slow pace of grid expansion to integrate new capacity; poor offtaker financial health; uncertainty over progress of future auction rounds.
Ethiopia	Fast-growing power demand; excellent resources; long-term targets for renewable capacity and electrification.	Low market access for IPP contracts; lack of cost-reflective tariffs; unavailability of financing for large infrastructure plans; grid expansion delays.
Kenya	Robust power demand growth; diversification needs; supportive policy framework; high end-user electricity prices.	Administrative and regulatory barriers; delays in PPA signing with the offtaker; high financing costs; land acquisition and grid connection delays.

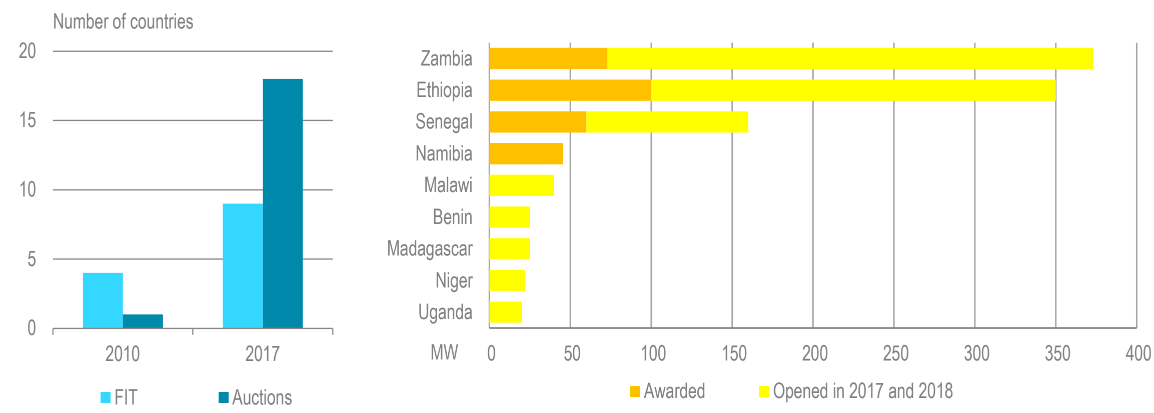
Other countries in sub-Saharan Africa: Main case forecast

Renewable capacity in the rest of the region is set to expand 14 GW, led by solar PV (5.7 GW) and closely followed by hydropower additions (5.2 GW). Utility-scale projects are expected to dominate solar PV growth, with competitive auctions becoming the policy of choice in an increasing number of countries in the region (Figure 2.35). This trend was initiated by successful implementation of the REIPPP programme in South Africa and further strengthened by the Scaling Solar initiative; the

World Bank and the IFC support the programme by providing guidance in auction design and implementation, and assist with favourable debt financing options. In 2017, **Ethiopia**, **Namibia** and **Senegal** awarded 206 MW of solar PV capacity through both national and Scaling Solar auctions. In Senegal, the contracted price was close to the global average PV auction price at USD 47/MWh. In 2017, auctions for a further 375 MW of solar PV were opened in **Senegal, Madagascar** and **Ethiopia**, all under the Scaling Solar programme, and in the first half of 2018, **Malawi**, **Benin**, **Nigeria** and **Uganda** opened solar PV auctions under their national schemes.

Hydropower expansion in the rest of the region depends on resource availability and is driven by rising power demand, efforts to extend electricity access and the desire to maximise export potential. Government companies remain the developers of hydropower projects through engineering, procurement and construction (EPC) contracts, which are increasingly signed with Chinese developers and backed by concessional financing from international institutions. **Zambia** is to expand 0.8 GW with commissioning of the Kafue Gorge Lower hydropower project, constructed and financed by Chinese entities, and in early 2018, **Zimbabwe** fully commissioned the 0.3-GW Kariba South Extension dam developed by Sinohydro. The Ruzizi III hydropower dam (0.15 GW) in the **Democratic Republic of Congo** secured financing from the African Development Bank (AfDB) and the European Development Fund in 2017. **Angola's** hydropower is set to expand by 1.4 GW of capacity with commissioning of the Laúca dam, supported by the Development Bank of Southern Africa.

Figure 2.35 SSA: Renewable electricity policies (left) and solar PV forecast for selected countries by auction stage (right)



Source: IEA (2018a), *Renewable Auctions* (database).

SSA: Accelerated case forecast

SSA renewable power capacity growth could be 1.5 times higher, translating to an additional 14 GW of capacity (Table 2.14), but this would require faster commissioning of planned projects and the approval of additional renewable capacity. Realisation of the region's potential depends strongly on obtaining affordable financing from public, private and international institutions.

South Africa's renewable energy capacity could expand an additional 2 GW over the forecast period, provided that new rounds of auctions are held in the short term, followed by timely PPA signing. Improvement in Eskom's management and financial situation would also facilitate extra growth by reducing investor risks and lowering the overall cost of financing. **Ethiopia**'s renewable capacity could be 2 GW higher with faster commissioning of the 250-MW Ganale Dawa VI hydropower station and additional affordable financing for wind and solar PV projects that are currently in the planning stage. **Kenya**'s capacity could expand an additional 3.4 GW with larger contributions from both on-grid and off-grid PV projects, followed by onshore wind. This could be possible with further clarity on the future support framework, the removal of administrative barriers concerning land acquisition and timely grid connection. **Nigeria** could expand an additional 4 GW in hydropower (3 GW) and solar PV (1 GW) with faster construction of the Mambilla hydropower station and access to concessional financing for announced PV projects. **Tanzania**'s renewable power capacity could expand an additional 0.7 GW, provided that the construction of projects that have already secured financing goes more quickly, problems surrounding land acquisition are resolved, and offtaker reliability improves.

Table 2.14 SSA: Main and accelerated case forecast summary, 2017 and 2023

Total capacity (GW)	South Africa			Ethiopia			Kenya			SSA		
	2017	2023 Main	2023 Acc.	2017	2023 Main	2023 Acc.	2017	2023 Main	2023 Acc.	2017	2023 Main	2023 Acc.
Hydropower	3.6	3.6	3.6	3.8	9	9.8	0.8	0.8	0.8	29.3	41.2	45.7
Bioenergy	0.3	0.5	0.6	0.2	0.2	0.4	0.1	0.2	0.2	1.7	2.2	2.7
Onshore wind	2.1	3.5	4.2	0.3	0.9	1.3	0	0.5	1.8	2.6	6.2	8.9
Offshore wind	-	-	-	-	-	-	-	-	-	-	-	-
Solar PV	1.8	3.3	4.3	0	0.5	0.9	0	0.4	2.3	2.9	12.5	17.9
CSP	0.3	0.6	1.2	-	-	-	-	-	-	0.3	0.6	1.2
Geothermal	-	-	-	-	-	-	0.6	1.2	1.3	0.6	1.2	1.5
Marine	-	-	-	-	-	-	-	-	-	0	0	0
Total	**8.1**	**11.7**	**13.9**	**4.4**	**10.7**	**12.5**	**1.6**	**3.1**	**6.5**	**37.4**	**64**	**77.8**

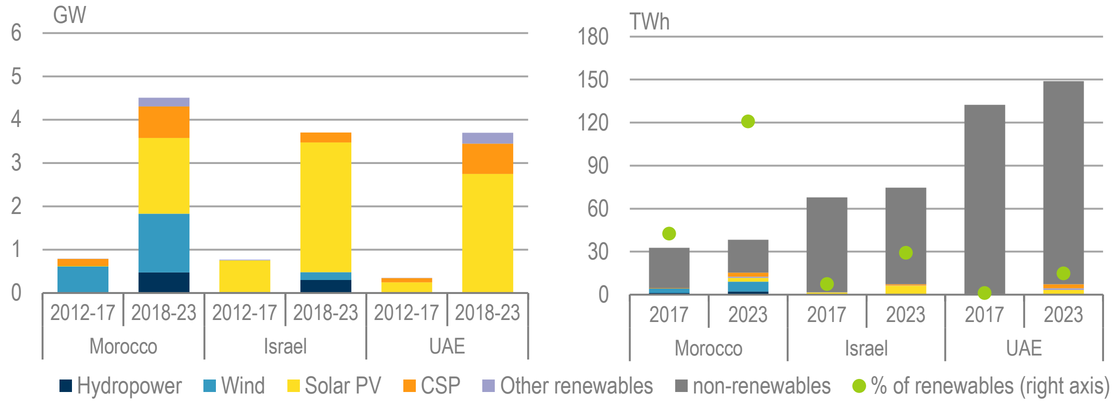
Note: Rounding may cause non-zero data to appear as "0" or "-0"; actual zero-digit data are denoted as "-".

The Middle East and North Africa (MENA)

Renewable capacity in MENA is projected to increase by 85% (23 GW) over 2018-23. Solar PV, which accounts for almost two-thirds of this growth, dominates the region's renewable expansion, followed by onshore wind (4 GW), hydropower (2 GW) and CSP (1.8 GW). Overall, the forecast is more optimistic than last year's, as progress under a number of procurement schemes has been quicker than expected in the past year. Almost two-thirds of the non-hydropower growth in the region is expected to be driven by IPP competitive auctions, with the remainder from FIT schemes, EPC contracts, or bilateral contracts with offtakers, including state-owned utilities and industrial consumers. Morocco lead's the region's growth, followed by Israel[9], the United Arab Emirates, followed by Egypt, Iran, Jordan, and Saudi Arabia (Figure 2.36).

[9] The statistical data for Israel are supplied by and under the responsibility of the relevant Israeli authorities. The use of such data by the OECD is without prejudice to the status of the Golan Heights, East Jerusalem and Israeli settlements in the West Bank under the terms of international law.

Figure 2.36 MENA: Renewable electricity capacity growth, 2012-23 (left), and generation by source, 2017 and 2023 (right)



MENA: Main case forecast for selected countries

Morocco's renewable capacity is expected to more than double over the forecast period with the addition of 4.5 GW of capacity led by solar PV (1.7 GW), followed by onshore wind (1.4 GW), CSP (0.7 GW), hydropower (0.5 GW) and bioenergy (0.2 GW). New capacity needs, combined with excellent resource potential and long-term targets supported by a robust policy framework, are the main drivers of this growth. This year's forecast is more optimistic than last year's, mostly owing to increased predictability of future solar PV auctions after plans to tender 800 MW under NOOR PV II were announced. Almost 80% of the total renewable capacity growth will be driven by competitive auctions, and the remainder by EPC projects and onshore wind corporate PPAs. As such, the pace of auction implementation and the length of project development lead times will largely influence the annual deployment pattern, especially for CSP, solar PV and onshore wind. Outside of Moroccan Agency for Solar Energy (MASEN) auctions, growth from corporate PPAs with small consumers and distributed solar PV hold great potential, but it is limited by the inability to access the medium- and low-voltage grid and by delays in land acquisition and permitting (IEA, forthcoming).

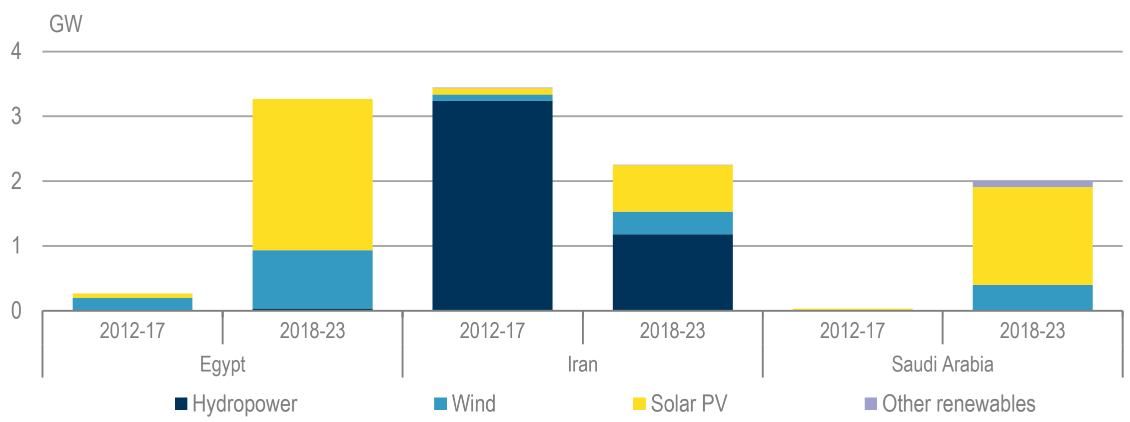
Israel's[10] cumulative renewable capacity is forecast to more than triple with the addition of 3.7 GW by 2023. Solar PV is expected to add 3 GW, a 2-GW upward revision from *Renewables 2017* owing to new policies targeting distributed solar PV. Auctions for large rooftop solar projects and an improved permitting process for residential systems under the FIT or net-metering scheme are expected to accelerate deployment, adding 2.1 GW of distributed generation capacity. Utility-scale project deployment is anticipated to be limited to 0.9 GW due to restricted land availability and transmission grid connection constraints. The 300-MW Gilboa PSH, the first PSH project in the country, is expected to be commissioned in 2018-19, adding flexibility to the power system, and the two CSP projects of the Ashalim complex are forecast to come online in 2018 and 2019 (230 MW). Onshore wind capacity is expected to grow 180 MW under the FIT scheme, but not reach the 730-MW quota due to lengthy permitting procedures.

[10] The statistical data for Israel are supplied by and under the responsibility of the relevant Israeli authorities. The use of such data by the OECD is without prejudice to the status of the Golan Heights, East Jerusalem and Israeli settlements in the West Bank under the terms of international law.

Renewable capacity in the **United Arab Emirates** is forecast to increase tenfold or 3.7 GW, led by solar PV (2.7 GW) and followed by CSP (700 MW) and bioenergy (250 MW) (Figure 2.37). Growth is stimulated by import diversification goals and the increasing economic attractiveness of CSP and solar PV. Competitive auctions will drive all of the CSP and utility-scale solar PV growth in the Mohammed Bin Rashid Al Maktoum Solar Park (MBR) in Dubai and Sweihan parks in Abu Dhabi. However, deployment potential continues to be constrained by barriers to new market entrants, and limited visibility over the auction schedule remains a forecast uncertainty. Distributed solar PV is expected to continue to grow among large consumers under the Shams net-metering scheme, but the relatively low retail tariffs that do not reflect associated costs hamper the economic attractiveness of residential PV systems. The forecast is revised up compared to last year due to a more optimistic outlook for CSP and bioenergy. Higher CSP deployment is expected after the 200-MW auction for Phase IV of the MBR was scaled up to 700 MW following highly competitive bids. The winning bid was for USD 73/MWh, a new global benchmark achieved through economies of scale, competitive financing, high capacity factors and a dual tower/trough design. In addition, increased capacity from energy-to-waste plants is expected to meet national targets to divert waste from landfills by 75% by 2021.

Egypt's renewable capacity expands by over 80% (3.3 GW) over the forecast period with solar PV and onshore wind capacity additions, driven by a mix of procurement and support schemes: FITs, build-own-operate (BOO) competitive auctions, state-owned EPC tenders, bilateral contracts and corporate PPAs. The forecast has been revised up from last year because solar PV prospects are more optimistic owing to recent developments under the FIT scheme, the introduction of competitive auctions in 2017 and increased economic attractiveness under net-metering and corporate PPAs. Overall, financing remains a challenge because of the currency risk and insufficient liquidity in local banks, causing concessional financing to remain critical. Annual deployment is projected to accelerate over the near term, mostly from robust solar PV growth while onshore wind additions are more volatile as slow project implementation and policy uncertainty pose challenges (Figure 2.37). Despite the acceleration in renewable capacity additions, the share in generation is forecast to reach just 10% by 2023.

Figure 2.37 MENA: Renewable capacity growth for selected countries, 2011-23



Solar PV leads growth, increasing by 2.3 GW (up from less than 100 MW in 2017) from FIT projects, auctions and distributed systems. At the end of 2017, approximately 1.5 GW of solar PV delayed under round 2 of the stalled FIT scheme reached financial closure after concessional financing was secured from a consortia of development finance institutions. Most of these projects are expected to come online in 2019-21, followed by projects under the country's first competitive auctions for 200 MW of solar PV. Additional growth is also forecast from distributed PV as it becomes more economically attractive under revised net-metering regulations and the continued phase-out of electricity tariff subsidies. An increase in the system size eligible for remuneration (from 500 kW to 20 MW) combined with rising retail electricity tariffs over the next few years is expected to drive growth from large-scale commercial systems.

In contrast, the **onshore wind** forecast carries more uncertainty. The status of approximately 500 MW of wind projects under the FIT scheme appears to be stalled, and it is uncertain whether they will be rolled into competitive auctions or cancelled completely. Furthermore, an estimated 2.7 GW of projects from IPP and EPC procurement schemes are under various stages of development, but project implementation delays make forecasting commissioning dates a challenge. While the signing of the first PPA from the IPP BOO tenders for USD 38/MWh is seen as a positive development, the state-owned utility may request this low price from other developers and this is believed to be contributing to the lengthy contract agreements. The lack of available grid capacity remains an important challenge for both public and private developers.

Iran's renewable capacity is forecast to grow roughly 20% (2.3 GW), led by hydropower (1.2 GW), followed by solar PV (0.7 GW) and onshore wind (0.35 GW). The forecast has been revised down from last year, due mostly to slower-than-expected progress of planned onshore wind and hydropower projects. Feed-in tariffs remain the main driver of non-hydropower growth and have spurred robust pipelines for solar PV and onshore wind, amounting to 2.5 GW of signed PPAs at the time of writing. However, there are several forecast uncertainties regarding the realisation of these projects. Financing remains a critical challenge, particularly after the US announcement to restore trade and financing restrictions. For solar PV, project bankability is becoming increasingly uncertain due to currency risks, restricted land access and the impact of import duties and taxes on project costs. Short commissioning deadlines proposed by the FIT scheme relative to the length of construction time poses additional forecast uncertainty. Distributed solar PV growth has been revised up slightly, as a new government campaign to increase consumer awareness of the net-metering scheme is expected to drive additional expansion.

Table 2.15 MENA: Main drivers and challenges of renewable electricity deployment

Country	Drivers	Challenges
Morocco	Long-term targets; competitive auctions; dedicated entity responsible for executing renewable energy plans.	Restricted access to distribution grid; land and permitting challenges for projects outside of auctions.
Israel	Excellent resource potential; clear support schemes; increasing economic attractiveness.	Restricted land availability; transmission grid congestion; lengthy permitting processes.
UAE	Fast-growing power demand; competitive auctions and net metering for distributed solar PV.	Restricted market access for IPP contracts outside of auctions; limited visibility over auction schedule; subsidised end-user electricity tariffs.

Saudi Arabia's renewable capacity is anticipated to increase from negligible amounts to 2 GW by 2023 to meet fast-growing power demand and national targets to install 9.3 GW of renewable capacity by 2023. Solar PV leads the growth (1.5 GW), followed by wind (0.4 GW) and CSP (93 MW). The National Renewable Energy Plan's (NREP's) competitive auctions are the main drivers for growth, but policy uncertainty and local content requirements may challenge the pace of deployment. This forecast is more optimistic than last year's given the faster-than-expected progress of solar PV auctions under the NREP. The NREP's first round for 300 MW of solar PV was awarded with a record-low bid of USD 23.4/MWh in February 2018, and shortly afterwards plans for an additional 3.3 GW in future rounds were announced. However, in the absence of a clear auction schedule the timing of future NREP auctions remains a forecast uncertainty. In addition, the government announced the Solar Power Project 2030 targeting 200 GW by 2030, but the implementation plan for this target relative to existing auctions remains unclear at the time of writing. The forecast for onshore wind is also driven by NREP auctions for the 400-MW Dumat Al Janal tender, with winners expected to be announced by the end of 2018. Additional wind auctions are anticipated, but the schedule has not been published and thus remains a forecast uncertainty. Additional growth is expected from distributed solar PV as it becomes increasingly economically attractive with the introduction of a new net-metering scheme and rising electricity tariffs planned for 2018-25.

MENA: Accelerated case forecast

Renewable growth in MENA's accelerated case could be more than twice that of the main case with additional deployment of solar PV, wind, CSP and PSH plants (Table 2.16). As competitive auctions drive the bulk of the growth, additional renewable capacity growth depends largely on faster auction implementation to realise longer-term plans. The accelerated case for the MENA region also captures the emerging trend of expanding PSH plans announced in several countries to accommodate the increase of variable renewables targeted.

Renewable capacity growth in **Egypt**'s accelerated case is more than double that of the main case owing to increased solar PV, onshore wind and hydropower deployment. The additional growth comes from faster implementation of the plans announced under all procurement schemes for solar PV and wind. This includes opening planned tenders, reaching financial closure and signing PPAs for winning projects already auctioned, and speeding up the government's planned EPC projects; more frequent increases to end-user electricity tariffs would also drive increased deployment of projects under corporate PPAs and net-metering schemes. Additional hydropower growth results from faster project development of the recently announced plans for the 2.4-GW Ataqa hydropower PSH project.

Morocco's accelerated case is driven by increased smaller-scale hydropower deployment (less than 30 MW) and faster implementation of auctions plans for onshore wind, CSP and solar PV. Additional growth from PV and wind projects outside of auctions also drives the accelerated case, but this strongly depends on access to the distribution grid. This is key for projects developed by IPPs aiming to sign bilateral contracts and for distributed solar PV projects to define remuneration through net-metering. The **United Arab Emirates**' accelerated case includes faster procurement of the competitive auctions for solar PV and CSP. A more rapid uptake of distributed solar PV under net metering in Dubai and Abu Dhabi would also occur should residential electricity tariffs increase. Additional hydropower growth is also part of this case, with the first units from the Al Hatta Dam PSH plant coming online.

Table 2.16 MENA: Main and accelerated case forecast summary, 2017 and 2023

Total capacity (GW)	Morocco			Israel[11]			UAE			MENA		
	2017	2023 Main	2023 Acc.	2017	2023 Main	2023 Acc.	2017	2023 Main	2023 Acc.	2017	2023 Main	2023 Acc.
Hydropower	1.8	2.3	3.6	0	0.3	0.3	-	-	0.4	21.7	23.7	27.4
Bioenergy	0	0.2	0.3	0	0	0	0	0.3	0.9	0.2	0.6	1.4
Onshore wind	0.9	2.2	2.4	0	0.2	0.3	0	0	0	2.3	6.3	11.8
Offshore wind	-	-	-	-	-	-	-	-	-	-	-	-
Solar PV	0	1.8	3.4	0.9	3.9	3.9	0.3	3.0	5.5	2.6	17.4	31.9
CSP	0.2	0.9	1.3	-	0.2	0.2	0.1	0.8	1.1	0.3	2.1	3.2
Geothermal	-	-	-	-	-	-	-	-	-	0	0	0
Marine	-	-	-	-	-	-	-	-	-	-	-	-
Total	**2.9**	**7.4**	**11.1**	**1.0**	**4.7**	**4.8**	**0.4**	**4.1**	**7.9**	**27.1**	**50.1**	**75.7**

Note: Rounding may cause non-zero data to appear as “0” or “-0”; actual zero-digit data are denoted as “-”.

The accelerated case for **Iran** assumes that all the PPAs signed under the FIT scheme for solar PV and wind come online within the forecast period. This would require a relatively seamless process of reaching financing closure, acquiring permits and land access, and addressing any clauses in the PPAs that would increase bankability risks for the developers. Faster construction of the PSH plant would also boost the hydropower capacity by 2023. **Saudi Arabia** has the highest potential for additional growth, should all the announced plans under the NREP auctions and the first phase of the Solar Power Project 2030 be online by 2023. This would require a clear future auction schedule and smooth project development through to commissioning, which has not yet occurred given the infancy of both plans. Additional expansion of distributed systems could also happen, should the proposed net-metering regulations enter into force and the electricity tariff subsidy phase-out occur more quickly.

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3. TRANSPORT BIOFUELS

Highlights

- Global conventional biofuel production, which reached a record 143 billion litres (L) in 2017, is anticipated to grow to 165 billion L by 2023, broadly in line with last year's forecast. The Asia-Pacific region and People's Republic of China[1] combined are responsible for half of production growth, with security of supply a key driver. Latin America produces most of the remainder, with Brazil's biofuel output growing the most of any country during the forecast period (2018-23).
- In 2020, Brazil and China will introduce policies that are anticipated to significantly raise biofuel market prospects. Brazil's flagship RenovaBio policy is designed to strengthen the economics of biofuel production, boosting investment in new capacity and output from existing plants, and China is extending its 10% ethanol blending mandate nationwide, which results in a notable upward revision of the forecast. However, the turn of the decade coincides with weakening policy support for conventional biofuels in the European Union.
- Under more favourable market and policy conditions, global conventional biofuel output in the accelerated case reaches 206 billion L in 2023 – 25% above the main case. Ethanol production could rise an additional 26 billion L, mainly in Brazil, China and the United States. Biodiesel and hydrotreated vegetable oil (HVO) output could increase 15.5 billion L, with Brazil, India and Indonesia the key contributors.
- Less mature advanced biofuel technologies, using non-food crops, waste or residue feedstocks, deliver 1.4 billion L of production by 2023 in the main case forecast, and 2.3 billion L in the accelerated case. This is only 1-1.5% of all biofuel output anticipated in 2023. More widespread policy support and reliable performance from first-of-a-kind commercial plants to lower the investment risk for follow-on projects is needed to scale up advanced biofuel production. Technically mature waste oil and animal fat biodiesel and HVO fuels will still account for most advanced biofuel production in 2023.
- Advanced biofuel markets are developing in areas that have established policy mechanisms to foster research, development and deployment. Over three-quarters of announced and under-construction advanced biofuel plants using less mature technologies are in Europe, India and the United States, where policy frameworks to support deployment are in place.
- Biofuel demand in the aviation sector is growing, but production remains low. Aviation biofuels currently cost more than fossil-based jet fuel, and enhanced policy support is needed to encourage demand and de-risk refinery investment. Stronger national policy support, introduction of the Carbon Offsetting and Reduction Scheme for International Aviation (CORSIA) and increased supply could place aviation biofuels in a position to meet 2% of international aviation demand in the medium term.
- Biofuels can reduce a range of air pollutants from current gasoline and diesel vehicle fleets, which could be a key driver for their use in countries with pressing air quality concerns caused by older vehicle fleets operating in large urban agglomerations. However, in modern vehicles that comply with the latest emission standards, the difference in air pollutant emissions between biofuels and fossil fuels is less significant.

[1] Hereafter "China".

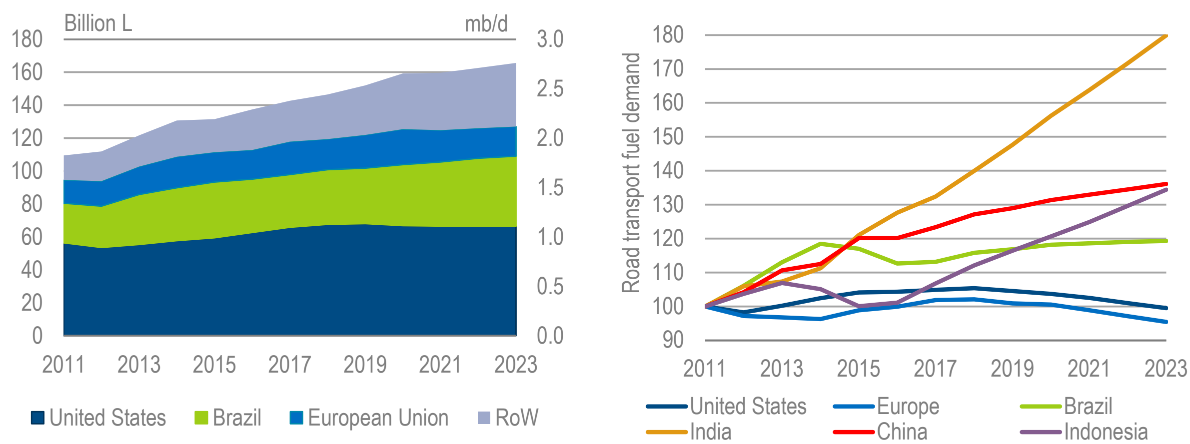
Conventional biofuel markets

Global overview

In 2017, conventional biofuel production increased 4% year-on-year (y-o-y) to reach 143 billion L, with an energy value of 83 million tonnes of oil equivalent (Mtoe) (Figure 3.1, left). World biofuel production is estimated to grow another 15% to 165 billion L by 2023, equivalent to 97 Mtoe – an upward revision from last year's forecast owing to robust growth prospects in Asia and Latin America.

As mandated blending is the principal policy support for biofuels, rising fuel demand results in higher biofuels consumption. Global demand for road transport fuel is projected to increase 5% over 2018-23, driven mainly by higher consumption in Asian countries where private vehicle ownership is becoming more widespread (Figure 3.1, right). Nevertheless, global biofuel production growth outpaces fuel demand growth over the forecast period.

Figure 3.1 Global conventional biofuel production (left) and indexed road transport fuel demand in selected countries, 2011-23 (right)



Notes: RoW = the rest of world. 2011 = 100.

Sources: IEA (2018b), *Monthly Oil Data Service (MODS)*, May 2018, www.iea.org/statistics/; IEA (2018c), *Oil Information* (database), www.iea.org/statistics/; MAPA (2018), *Produção*, www.agricultura.gov.br/assuntos/sustentabilidade/agroenergia/producao; US EIA (2018a), *Petroleum and Other Liquids*, www.eia.gov/petroleum/data.cfm.

Asian countries account for the most growth in biofuel output over the forecast period: China, India and Association of Southeast Asian Nations (ASEAN) countries combined provide half of the global biofuel production expansion (Table 3.1). These markets demonstrate rising gasoline and diesel demand over the forecast period, so offsetting some crude oil and petroleum product imports, as well as reinforcing supply security, gives impetus to greater biofuel production. Consequently, policies supporting consumption of domestically produced biofuels is strong in these countries, and further measures were introduced in 2017 (Table 3.2). High feedstock availability also supports production in Asia.

Latin America accounts for 45% of production growth in the forecast period, principally from Brazil, where biofuel output increases the most of any individual country. The prime driver of this growth is the new RenovaBio policy framework due to be introduced in the first half of the forecast period. This policy was developed to support Brazil's national target of an 18% share of sustainable biofuels in the energy mix by 2030. Once it comes into force in 2020, ethanol, biodiesel and advanced biofuel demand is anticipated to grow.

Table 3.1 Global conventional biofuel production

Billion L	2017	2018	2019	2020	2021	2022	2023	CAAGR
North America	68.0	69.0	69.3	68.7	68.6	68.4	68.7	0.2%
United States	65.8	66.6	66.8	66.0	65.6	65.5	65.7	0.0%
Latin America	38.4	43.3	44.5	45.8	45.2	47.5	49.0	4.2%
Brazil	32.0	36.5	37.4	38.7	38.9	41.3	42.6	4.9%
European Union	20.0	18.6	20.2	21.6	19.3	18.3	18.0	-1.8%
China	4.6	5.2	5.8	6.7	7.3	8.0	9.1	12.3%
Asia-Pacific	10.8	11.2	13.0	15.2	16.4	17.4	18.0	9.0%
ASEAN	9.0	8.8	10.3	11.9	12.7	13.4	13.9	7.6%
India	0.9	1.3	1.4	1.8	2.1	2.3	2.6	18.5%
Rest of world	1.6	1.6	1.7	2.1	2.0	2.0	2.1	5.0%
World	**143.3**	**148.8**	**154.5**	**160.1**	**158.7**	**161.7**	**164.9**	**2.4%**

Notes: Asia-Pacific excludes China; Latin America excludes Mexico, which is included in North America; CAAGR = compound average annual growth rate.

Sources: IEA (2018b), *Monthly Oil Data Service (MODS)*, May 2018, www.iea.org/statistics/; IEA (2018c), *Oil Information* (database), www.iea.org/statistics/; MAPA (2018), *Produção*, www.agricultura.gov.br/assuntos/sustentabilidade/agroenergia/producao; US EIA (2018a), *Petroleum and Other Liquids*, www.eia.gov/petroleum/data.cfm.

Output in North America is anticipated to be broadly stable (Table 3.1) as a slight reduction in corn ethanol production in the United States outweighs higher ethanol output in Canada and Mexico. Conventional biofuel production in the EU is forecast to contract by 10% by 2023 as transport fuel demand declines and the policy framework becomes less supportive of conventional biofuels after 2020, which hamper investment in new production capacity. Although the updated Renewable Energy Directive (RED) is likely to raise the transport sector renewable energy consumption target from 10% to 14%, the updated framework favours advanced biofuels and renewable electricity consumption over conventional biofuels, the maximum contribution of which will be limited to 7%.

Fuel ethanol[2] accounts for two-thirds of conventional biofuel output growth over 2018-23. Global ethanol production increased 3% y-o-y in 2017, as output reached 104 billion L, with higher production primarily in the United States, the European Union and China. Ethanol production is forecast to expand at an CAAGR of just over 2% to 119 billion L by 2023, an upward revision from last year's forecast. Growth is driven by Brazil, followed by China and expanding markets in India and Thailand. In 2023, China's share of global production increases, but the United States and Brazil still dominate ethanol production, accounting for 80% of global output.

Combined biodiesel and HVO production increased 7% from 2016, with a record output of almost 39 billion L in 2017. Global production is expected to grow at a CAAGR of 3% until 2023, reaching 46 billion L, with market expansion driven by higher mandated demand in the United States, Brazil and some ASEAN countries, notably Indonesia.

HVO, also known as renewable diesel, is increasingly prominent in the *Renewables 2018* biofuel forecast. In 2017, 5.5 billion L of HVO output accounted for 14% of global combined HVO and

[2] All references to ethanol in *Renewables 2018* are to fuel ethanol for transport use.

biodiesel production, and HVO output is anticipated to grow over 2018-23 with the expansion of existing facilities and new plants coming online in Europe and the United States.

Table 3.2 Mandates, targets and carbon intensity policies for biofuels in selected countries

Country	Ethanol	Biodiesel	Carbon intensity policy	Recent updates
United States	82 billion L of renewable fuels in 2018 and 136 billion L by 2022		LCFS in California and Oregon	-
Canada	5%	2%	LCFS in British Columbia; federal clean fuel standard in development	10% ethanol mandate in Ontario from 2020; clean fuel standard for liquid fuels in 2022
European Union	10%* renewable energy in transport by 2020 (T) with 7% cap for conventional biofuels		GHG intensity of fuels to fall 6% by 2020	Provisional agreement for 14%* renewable energy in transport in 2030
France	7.5%*	7.7%*	-	Conversion kits to allow cars to use E85 approved
Germany	-	-	Climate Protection Quota (CPQ) 6% reduction in 2020	Upstream fossil fuel emissions reductions eligible for CPQ target
Italy	7%* biofuels		-	-
Denmark	5.75%* biofuels		-	-
Finland	30%* biofuel supply obligation by 2030		-	-
Sweden	-		Emissions reduction obligation system introduced	-
United Kingdom	12.4% renewables share by 2032 in RTFO		-	RTFO target extended to 2032; cap on conventional biofuels of 4% in 2020, 2% in 2032
China	10%	-	-	10% ethanol mandate to extend nationwide in 2020
India	5%	-	-	Biofuels policy expands approved feedstocks for ethanol production
Indonesia	20%	2%	-	Mandated consumption extended to new sectors, including rail and mining
Malaysia	-	7%	-	-
Thailand	32% by 2036 (T)	Currently 7%, and 25% by 2036 (T)	-	-
Argentina	12%	10%	-	-
Brazil	27%	10%	RenovaBio signed into law, 10% GHG reduction by 2028 (T)	-

Notes: LCFS = Low Carbon Fuel Standard; GHG = greenhouse gas; RTFO = Renewable Transport Fuel Obligation. Dark green indicates policy changes since last year's report; light green indicates no recent policy changes; values are mandates unless (T) specified to indicate target; percentage values are by volume except where a * is used to indicate by energy. The 14% EU target is provisional pending final legislation, and multiplication factors for advanced biofuels and renewable electricity are also utilised in the EU policy framework. Member states may deploy conventional biofuels in excess of the 7% cap, but it would not be counted towards EU renewable energy targets. Mandate values in Canada are federal; provincial requirements vary. Carbon intensity relates to GHG emissions produced from a fuel on a lifecycle basis.

Ethanol markets: Regional outlook

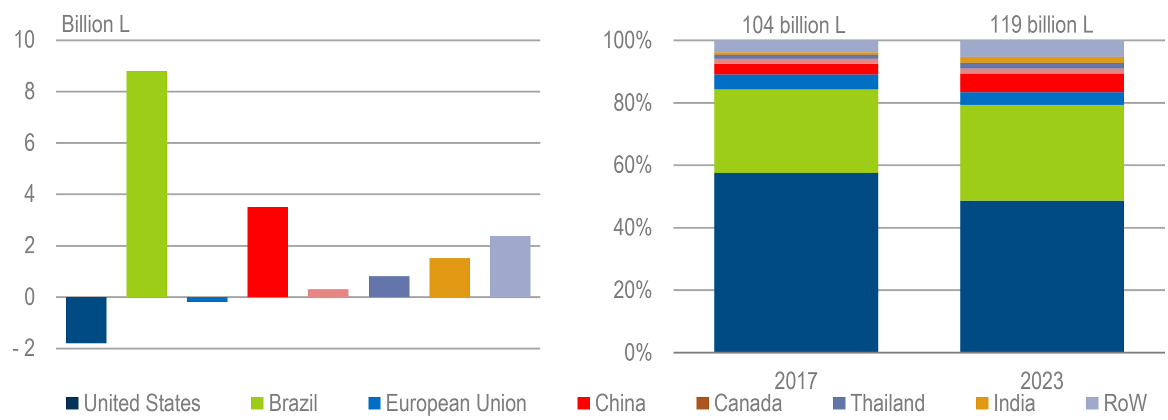
In the **United States**, ethanol production rose by around 5% y-o-y to almost 60 billion L in 2017. Growth was supported by another abundant corn crop, which kept corn prices stable and allowed for profitable ethanol production. Consequently, ethanol facilities demonstrated high capacity utilisation.

Over the next six years, output is forecast to decrease slightly (Figure 3.2) due to 1) limited investment in new capacity, 2) attainment of the allowable limit for corn ethanol under the Renewable Fuel Standard (RFS2) and 3) reduced gasoline demand resulting from an improved fuel efficiency of the vehicle fleet. Renewable fuel volumes under the RFS2 are established up to 2022 only; however, because of the RFS2's importance to the agricultural sector and ethanol's octane value, this forecast assumes that the policy remains in place to support biofuel demand in 2023.

Corporate Average Fuel Economy (CAFE) standards are considered to remain unchanged in the forecast, but they could also be subject to modification post-review. If they are relaxed, the pace of fuel efficiency improvements would decline, resulting in a weaker drop in gasoline (and in turn blended ethanol) demand.

To support further investment in ethanol production capacity, consumption of higher-ethanol blends than E10[3] and increased exports will be needed. Availability of E15 and E85 ethanol blends is growing, but is restricted to only small percentage of service stations nationally; their consumption therefore has only a relatively modest impact on the forecast. In 2017, US ethanol exports reached record levels (5.3 billion L) and, based on data for the first half of 2018, are set to increase further still. Brazil, Canada and India were the principal destinations last year, and recent regulatory changes support higher exports to Japan and Mexico over the forecast period.

Figure 3.2 Forecast change in ethanol production between 2017 and 2023 (left) and share of global ethanol output by country (right)



Ethanol output in **Brazil** contracted slightly in 2017 to 27.7 billion L, although lower international sugar prices in the second half of the year raised the relative profitability of ethanol production compared with that of sugar. Ethanol price competitiveness at the pump was also aided by lower federal taxation on ethanol than on gasoline in 2017, and higher crude oil – and consequently

[3] Gasoline blended with 10% fuel ethanol by volume. E15, E20 and E85 refer to 15%, 20% and up to 85% ethanol by volume.

gasoline – prices in 2018 also make ethanol more cost-competitive. Continued low international sugar prices and strong demand for unblended hydrous ethanol at the pump resulted in a significant y-o-y increase in ethanol production during the first half of 2018. This has been delivered by mills maximising ethanol production at the expense of sugar.

Ethanol production is anticipated to increase to 36.5 billion L by 2023, at a CAAGR of just under 5%. The high proportion of flexible fuel vehicles (FFVs) on the road is a key driver for ethanol demand: FFVs already account for more than 70% of the vehicle fleet and their share is growing. Combined with the cost-competitiveness of unblended hydrous ethanol, consumption is anticipated to rise over the forecast period, stimulating higher production. The 27% ethanol blending mandate is not anticipated to be raised, so growth prospects for unblended anhydrous ethanol are lower.

Brazil's flagship biofuels policy, RenovaBio, has been signed into law and implementation is to commence in 2020. A national target to reduce GHG emissions 10% by 2028 has been set, and to achieve it RenovaBio will establish national emissions reduction targets for fuel distributors relative to their market share, as well as a tradeable credit system to demonstrate they are met. Credits will be issued for biofuel production based on the emissions reduction potential of the fuel compared with petroleum products, with each credit equal to 1 tonne of mitigated carbon dioxide (CO_2).

RenovaBio is expected to provide a supportive framework for further ethanol production capacity investment. This is mainly anticipated from the expansion of existing sugar mills over the first half of the forecast period, complemented by greenfield investments after 2020. Ethanol production capacity could increase further to support the forecast by:

- Recommencing operations at idle mills if/when economic conditions are favourable. Around 80 mills are anticipated to be offline during the 2018/19 harvest season.
- Increasing the share of ethanol production at the expense of sugar. The majority of Brazil's mills produce both sugar and ethanol, and while there are process limits on the share of sugar output, mills could, in theory, be adjusted to produce 100% ethanol.
- Continuing expansion of corn ethanol production, which is still at an early stage.

In 2017, **China** increased ethanol output by 7% y-o-y to 3.5 billion L; production is forecast to reach just over 5 billion L in 2020, broadly in line with the 13th Five-Year Plan target, and then continue to grow to around 7 billion L by 2023. The purposes of this policy are to offset a portion of crude oil imports and to utilise accumulated corn stocks no longer fit for human consumption. Reforms making the use of grains in storage more market-driven and hastening their consumption for ethanol production also support this production forecast.

Ethanol has been designated a national strategic emerging industry, and plans to roll out E10 blends of ethanol nationwide by 2020 were announced in autumn 2017, expanding current consumption from 11 provinces. If fully implemented, the result would be significantly scaled-up demand of over 17 billion L. Consequently, several new large-scale ethanol plants are already in development, with the main corn-growing region in north-eastern China the focal point of industry growth. While the production forecast has been revised up from last year, it is anticipated that domestic output will fall short of fully meeting E10 demand nationwide within the forecast period, especially in the context of ongoing 2% average annual gasoline demand growth. The use of imports to make up any shortfall in projected demand is as yet unclear.

Ethanol production in the **European Union** rose almost 16% y-o-y in 2017, reaching 5 billion L; this record production was delivered by increased output in France, Belgium and the United Kingdom, while output in Germany remained stable. With the exception of the United Kingdom, E10 gasoline blends are available in all of these countries as well as Finland; in Belgium, E10 holds an 80% share of the gasoline market. The main feedstocks used for ethanol production in Europe are wheat and corn, although the share of ethanol produced from sugar beets is anticipated to grow owing to the bumper harvest in 2018 and the abolition of EU sugar production quotas.

As national policies support scaled-up production towards 2020, in line with the RED target of 10% renewable energy in transport, ethanol production is expected to reach 5.8 billion L by 2020. Increased ethanol output results principally from higher capacity utilisation at existing plants, with limited new capacity investment anticipated over the forecast period as EU policy support for conventional biofuels weakens after 2020 in the updated RED.

Output after 2020 therefore falls slightly as a result of declining gasoline demand across the European Union and the updated RED policy framework. Although the legislation is not yet finalised, the provisional agreement outlines that member states may increase the contribution of conventional biofuels to renewable energy in transport by up to 1 percentage point only from 2020 levels,[4] with the absolute cap of a 7% maximum contribution to renewable energy targets remaining in place. For the provisional 2030 target of 14% renewable energy in transport to be met, the remainder will need to come from advanced biofuels and renewable electricity in transport.

In 2017, the share of new diesel-fuelled car registrations fell 5% in the EU-15, largely offset by an increase in gasoline car sales (ACEA, 2018c). This trend of gasoline vehicles obtaining a greater share of new car sales at the expense of diesel could offset the anticipated reduction in gasoline demand from improved fuel efficiency. This would boost ethanol demand, and presents a forecast uncertainty.

Box 3.1 Could car conversion kits boost ethanol consumption in France?

E85 gasoline sales are on an upward trend In France, with more than one thousand service stations offering the blend. Demand is reinforced by a lower per-litre price than for other gasoline blends as a result of favourable taxation. However, E85 can only be used in FFVs that can use gasoline or blends of up to 85% ethanol, or mixtures of different blends. Prospects for E85 uptake are therefore tied to the proportion of the vehicle fleet that can use the fuel, and in consequence, E85 accounted for only 1% of gasoline vehicle fuel consumption last year.

However, conversion kits approved in 2017 that allow certain standard gasoline cars to use E85 could increase demand for the fuel in France. Conversion kits cost around EUR 700, depending on vehicle specifics, but the lower cost of E85 fuel could render the payback period relatively short, especially for drivers who accumulate high annual mileage. It is estimated that up to 10 million vehicles in France are suitable for kit installation (SNPAA, 2018), but obtaining manufacturer approval for their use could constrain uptake, and checks would have to be conducted to ensure tailpipe emissions are not adversely affected.

Ethanol production in **India** dropped 30% y-o-y from 2016's record output to around 800 million L in 2017 as a result of 1) drought conditions in key sugar cane harvest areas, which raised molasses

[4] Or two percentage points if a country's share is zero in 2020.

feedstock prices, 2) lower regulated procurement prices compared with those for competing uses, e.g. for industry and beverage production, and 3) the removal of an excise duty exemption for ethanol blending.

Nevertheless, long-term drivers for ethanol industry expansion remain strong. Over the forecast period, annual production is anticipated to increase almost threefold to 2.3 billion L, an upward revision from last year's forecast. This level of production is expected to be sufficient to meet the national 5% blending mandate.[5] With average annual gasoline demand growth of 9.5% over 2018-23, using domestically produced ethanol is viewed as a means to offset oil demand, in line with the aim to reduce crude oil imports 10% by 2022.

The new national biofuels policy widens the range of feedstocks allowed to be used as a base for ethanol – expanding it from only the molasses produced by India's large sugar industry, to include sugar cane juice, sugar and starch crops (e.g. corn and cassava) in years when there is a projected oversupply, and damaged food grains – which is anticipated to support forecast production growth. Furthermore, public sector financial support for greenfield and brownfield investments to increase fuel ethanol production capacity has also been introduced. However, national oil marketing companies' ethanol procurement processes will likely need to be streamlined, and inter-state logistical barriers (e.g. taxation) and constrained storage capacity at refineries will need to be dealt with to ensure the 5% mandate can be met.

Prospects for the ethanol industry in **Thailand** remain positive. In 2017, ethanol production reached 1.45 billion L, representing steady growth towards the 32% (4.1 billion L) ethanol blending target for 2036. With new production capacity coming online, output is forecast to increase 60% to reach 2.2 billion L by 2023, equivalent to an 18% share of gasoline demand. Production is primarily from molasses, but cassava-based ethanol production also increases over the forecast period. Rising gasoline demand, increasing availability of subsidised E20 and E85 blends, and tax incentives for the purchase of FFVs all support growth.

Biodiesel and HVO markets: Regional outlook

Biodiesel production increased 2% y-o-y in the **United States**, reaching almost 6 billion L in 2017. The USD 1/gallon blenders' tax credit expired at the end of 2017 and was not reinstated, lowering the profitability of biodiesel production. However, this tax credit has been retroactively reinstated in the past, so its future reintroduction cannot be ruled out.

Output is expected to increase 27% to 7.6 billion L by 2023, even given stagnant diesel consumption. Growth is underpinned by demand from the RFS2, and although the scheme details renewable fuel volumes up to 2022 only, it is assumed it will still be in place in 2023. In addition, the introduction of anti-dumping duties on biodiesel imports from Indonesia and Argentina in 2017 rendered them uneconomic. Although they could be partially replaced with imports from locations such as Malaysia, it is also considered that domestic biodiesel output will increase.

Biodiesel production in **Brazil** reached a record 4.3 billion L in 2017, representing 13% y-o-y growth. Average annual production growth of 6% is forecast over 2018-23, with output scaling up to 6 billion L. Soybeans are the main feedstock for biodiesel production, but introduction of the RenovaBio policy in 2020 may stimulate greater production from lower-carbon waste oil and animal

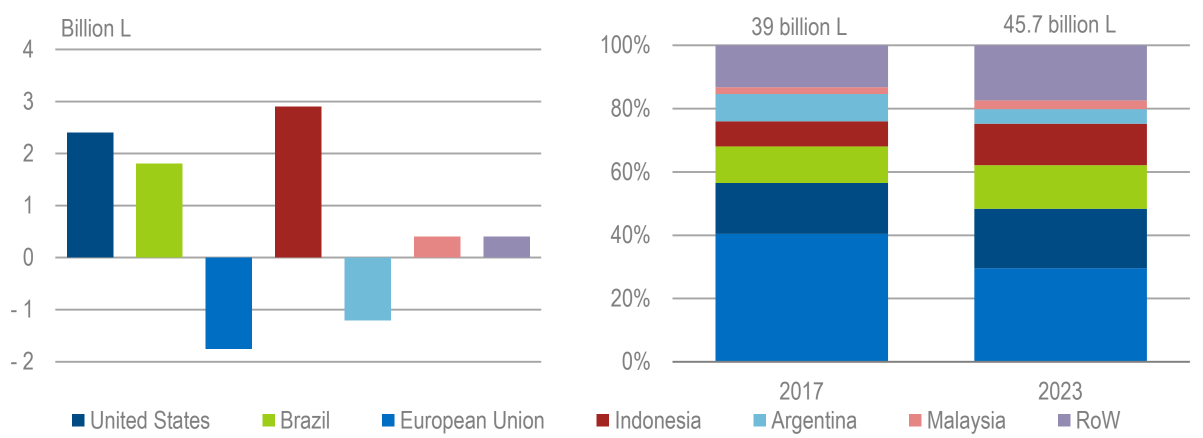
[5] A 10% blending target in place for the major ethanol-producing states.

fat feedstocks. An increase in the biodiesel blending mandate to 10% was also brought forward one year to March 2018, although growth under the mandate is slightly constrained by low diesel demand growth of 1% per year over the forecast period. Higher production should reduce current biodiesel plant overcapacity, but raising the mandate to 15% depends on automotive industry testing to assess the effects of using the higher blend level, and is therefore not included in this forecast.

Biodiesel and HVO production in the **European Union** increased 13% y-o-y in 2017, to a record 15 billion L. France, Germany and the Netherlands combined were responsible for 55% of output, and higher biofuel quotas in Finland, Italy, Poland and Spain in 2018 should support demand for biodiesel and HVO. Conversely, the removal of anti-dumping duties on biodiesel imports from Argentinian and Indonesian suppliers, and the subsequent recommencement of imports from these countries, constrains output of the least competitive European biodiesel.

Biodiesel and HVO production is anticipated to rise to around 15.5 billion L in 2020 as a result of stronger policy measures aimed at meeting national targets of 10% of renewable energy in transport under the RED. After 2020, production is likely to decline (Figure 3.3) as the future RED policy framework restricts crop-based biofuel production growth and as 6% lower diesel consumption over 2018-23 reduces mandated demand.

Figure 3.3 Forecast change in biodiesel and HVO production between 2017 and 2023 (left) and share of global biodiesel and HVO output by country (right)



Market prospects for waste- and residue-based biodiesel and HVO are expected to remain robust. Within the provisional agreement for the updated RED, when these fuels are produced from used cooking oil (UCO) and animal fat feedstocks, they would be capped at a contribution of 1.7% of the 14% 2030 target for renewable energy in transport. However, production from other feedstocks (e.g. tall oil and palm effluent sludge) is not subject to this cap. Overall, it is considered that there is potential for growth from current consumption levels within the updated RED policy framework.

Biodiesel output in **Argentina** increased slightly to 3.2 billion L in 2017, with more than half destined for export. The United States received 60% of 2017 exports, although the introduction of anti-dumping duties in autumn 2017 effectively closed the US market to Argentinian producers. Conversely, the reduction of EU biodiesel import tariffs resulted in an immediate restart of exports to Europe. However, falling European diesel demand and weaker biofuel policy support after 2020 means export potential may decline, reducing Argentinian production.

Production is therefore anticipated to drop to 2 billion L by the end of the forecast period, although this may not occur if alternative export or discretionary blending[6] markets open up. Annual diesel demand growth approaching 2% should support some increased domestic demand as a result of the 10% mandate; however, an increase in the mandate is not anticipated during the forecast period.

In **Indonesia** the biodiesel market is in transition from an export-driven focus towards higher domestic consumption. A significant increase in production from 3.4 billion L in 2017 to 5.8 billion L by 2023 is forecast, with growth underpinned by new plants coming online, complemented by a ramp-up in production from underutilised capacity. Demand is ensured by extension of the B20 mandate to new market segments and 4% per year diesel consumption growth.

The share of production exported is anticipated to decrease over the forecast period, but exports will still be an important part of Indonesia's biodiesel market in 2023. Although exports to Europe are expected to recommence with the lifting of EU anti-dumping duties in 2018, the European Commission has reopened an anti-dumping investigation into biodiesel imports from Argentina and Indonesia. As such, a reintroduction of duties cannot be ruled out, creating a forecast uncertainty.

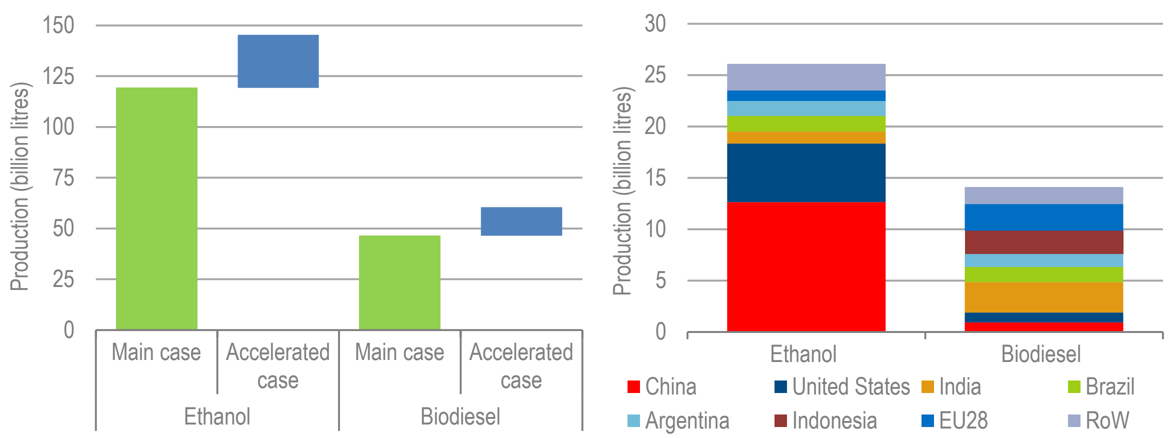
Annual biodiesel output in **Malaysia** is forecast to increase from 800 million L in 2017 to 1.2 billion L by 2023. This expectation is based on an assumed increase in the road transport blending mandate from B7 to B10 and 3% per year growth in diesel demand during the forecast period. Output growth is achievable without new plants, given current overcapacity in the industry.

Conventional biofuels: Accelerated case

Under more favourable market and policy conditions, the accelerated case for conventional biofuels reveals that global production could reach 206 billion L in 2023, a 25% increase from the main case.

In the accelerated case, annual ethanol production rises 26 billion L (Figure 3.4) to 145 billion L in 2023 (up 22% from the main case). The principal contributors to additional ethanol growth in the accelerated case are the United States, Brazil, China, India and Argentina (Table 3.3).

Figure 3.4 Main and accelerated case overview (left) and additional production breakdown by country (right)



[6] Voluntary blending above mandated demand when it is economic to do so.

Table 3.3 Annual ethanol production: Accelerated case (billion L)

Country	2023 main	2023 acc.	Increase	Brief explanation of accelerated case
United States	58.1	63.8	10%	Waiver to allow year-round E15 sales; higher E85 market share; increased exports; efficiency improvements to increase production.
Brazil	36.5	38.0	4%	RenovaBio effective in stimulating investment; low levels of lost capacity from mills in debt; higher corn ethanol output; energy cane rollout.
China	7.0	19.7	179%	10% nationwide ethanol blending fulfilled; reforms to hasten use of spent grain stockpiles for ethanol production.
India	2.3	3.5	51%	7.5% conventional biofuel blend share; streamlined OMC procurement processes; inter-state permit and taxation barriers resolved.
Argentina	1.2	2.7	117%	Increase in mandate from 12% to 26%; measures to stimulate high FFV sales; increased corn and sugar cane crop acreage.
Other countries	10.2	13.8	36%	Canada, Thailand, Mexico, Philippines, Viet Nam and the European Union also contribute to the accelerated case.

Note: OMC = oil marketing company.

Biodiesel and HVO output increases 15.5 billion L to reach 61 billion L by 2023 in the accelerated case (up 34% from the main case). The main contributors to biodiesel and HVO production in the accelerated case are Argentina, India, Brazil, Indonesia and Malaysia (Table 3.4).

Table 3.4 Annual biodiesel and HVO production: Accelerated case (billion L)

Country	2023 main	2023 acc.	Increase	Brief explanation of accelerated case
Argentina	2.0	3.3	62%	Removal of anti-dumping duties in the United States; continued high EU demand after 2020; opening of other export markets.
India	0.2	3.2	16-fold increase	Biodiesel industry invigorated by suitable oil crop, waste oil and animal fat feedstock supply chain mobilisation; higher uptake in rail and municipal captive fleets.
Brazil	6.1	7.6	24%	Automotive industry approval for 15% mandate; higher voluntary use in captive fleets; feedstock diversification with more use of tallow.
Indonesia	5.8	8.1	39%	Rollout of biodiesel consumption in industry; mandate increase to 25%; opening of new export markets.
Malaysia	1.2	2.5	116%	Move from current 7% to 15% mandate.
Other countries	23.4	29.5	26%	China, Singapore, the European Union and the United States also contribute to the accelerated case.

Advanced biofuel markets

Higher production of advanced biofuels is important for the long-term decarbonisation of the transport sector because they generally offer more significant GHG emissions reductions relative to fossil fuels than conventional biofuels. In addition, as they are produced from non-food feedstocks, they do not compete with food crops for prime agricultural land.

Technologies to produce biodiesel and HVO from waste oils and animal fats are technically mature and production is on an upward trend. Although data on production of these fuels is fragmented, it is estimated that they may account for 6-8% of global biofuel production. However, competition for waste oil and animal fat feedstock is intensifying, elevating their cost, and while there is scope to enlarge the supply of these raw materials, their availability is ultimately finite.

Other novel advanced biofuel technologies, such as cellulosic ethanol and diesel substitute fuels from thermochemical processes, are at a lower level of technological readiness. While production of these fuels is scaling up, they are still anticipated to account for only 1-1.5% (by volume) of all biofuel output in 2023. However, ongoing development is important because these fuels can exploit different low-carbon feedstock resources that are more readily available.

Widespread policy support is required to drive ongoing development of these less-mature technologies. Therefore, most advanced biofuel project development is anticipated to happen in Europe, India and the United States owing to policy frameworks that are favourable for the deployment of advanced biofuels. For a classification of biofuels according to the International Energy Agency's (IEA's) advanced biofuel definitions, see Box 3.2 below.

Box 3.2 Advanced biofuel definitions

The IEA considers **advanced biofuels** as sustainable fuels produced from non-food crop feedstocks, which are 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 cause adverse sustainability impacts.

However, advanced biofuels can be classified based on the maturity of the technology used to produce them. *Renewables 2018* presents a forecast for advanced biofuels from technologies that have not yet been fully commercialised, termed **novel advanced biofuels**. This distinction is made to highlight the status of technologies that require ongoing support to tackle financial, technical and market barriers.

Table 3.5 Classification of certain advanced biofuels

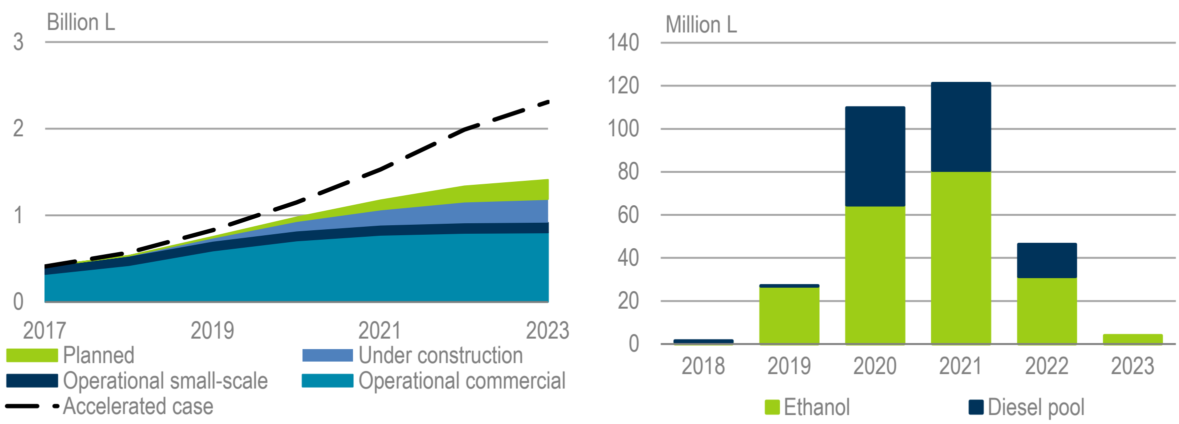
Fuel	Example feedstock	Technical maturity	Relevant definition	In novel advanced biofuel forecast?
HVO or biodiesel	Waste oils, animal fats	Full commercial	Advanced biofuel	No
Biomethane	High moisture content wastes	Full commercial	Advanced biofuel	No
Cellulosic ethanol	Agricultural residues	First-of-a-kind commercial scale	Novel advanced biofuel	Yes
Thermochemically produced diesel	MSW, forestry residues	Prototype / demonstration	Novel advanced biofuel	Yes

Notes: MSW = municipal solid waste. The maturity of diesel substitute fuels from thermochemical processes varies according to technology.

Novel advanced biofuels: Main case forecast

The *Renewables 2018* main case forecast expects annual production of novel advanced biofuels[7] to reach 1.4 billion L (0.9 Mtoe) in 2023 – a more than threefold increase from estimated 2017 production (Figure 3.5, right). This downward revision from last year's forecast reflects the small number of announced projects that are currently moving into construction. In addition, it highlights that a significant contribution from advanced biofuels in the transport sector is not anticipated by 2023. Cellulosic ethanol accounts for 60% of production within the novel advanced biofuels main case forecast, with the remainder from advanced biofuels for the diesel pool and aviation biofuels.

Figure 3.5 Novel advanced biofuel production (left) and annual capacity additions (right)



Note: Diesel pool refers to fuels suitable for diesel-fuelled vehicles. For the purposes of the forecast, this also includes biofuels used in the marine transport sector and aviation biofuels.

In the main case, utilisation rates of already-commissioned commercial-scale advanced biofuel plants rise from their currently low level to an average of 70% as a result of technical learning, thereby scaling up production to 800 million L in 2023 (Figure 3.5, left). Around 70 smaller-capacity plants, constructed for demonstration purposes, make a relatively minor contribution to production.

As of May 2018, nine commercial-scale advanced biofuel plants were in construction, adding 270 million L of production by 2023 if all are completed successfully and scale up production to 70% of their rated capacity. Utilisation rates of the highest-performing novel advanced biofuel plants are currently 40-50%.

The number of announced projects far outweighs facilities currently under construction. Therefore, the main case forecast assumes only one in five of announced projects is delivered, accounting for the remaining 220 million L of advanced biofuel production by 2023. This low delivery rate assumption reflects the difficulties many projects have in obtaining the financing needed to proceed beyond the early stages of development.

[7] Refers to fuels that meet the "advanced biofuel" definition but are produced using technologies that are not yet fully commercialised. Technically mature waste oil and animal fat biodiesel is not included in this category, and neither is HVO except when only waste and residue feedstocks are used. Biomethane plants are also not included due to data limitations on establishing fuel production from waste feedstocks destined for use in the transport sector.

Several replication projects based on technologies previously deployed in first-of-a-kind plants are currently in development. They build on learning experience from commissioned plants and therefore can attract financing more easily. Consequently, replication projects are assumed to ramp up production more quickly in the forecast.

There are currently few projects announced for commissioning in 2023, but so far, the majority of capacity additions during the forecast period are expected in 2020-21, with over 100 million L of capacity expected to be commissioned in both years.

The main case also presumes that in the United States three conventional corn ethanol plants per year are retrofitted with technology to produce cellulosic ethanol from corn fibre residues. Seven plants already use such technology, potentially equating to around 30 million L of cellulosic ethanol.

Novel advanced biofuels: Accelerated case forecast

The accelerated case for novel advanced biofuels forecasts nearly 2.3 billion L of production by 2023, almost 65% above the main case. The portion of cellulosic ethanol increases to two-thirds of production in the accelerated case, with one-third from advanced biofuels for use within the diesel pool and aviation biofuels.

This higher output is delivered by the first commercial-scale advanced biofuel plants, which contribute 900 million L by 2023 as they attain 80% utilisation rates, levels indicative of technically mature conventional biofuel plants in markets with strong demand. Achieving this level of output will require operational learning, improved pre-treatment processes and a supportive market and policy context to ensure offtake demand. It is assumed that four advanced biofuel plants that are currently idle – for both technical and non-technical reasons – restart and ramp up production.

The accelerated case also assumes more favourable conditions for investing in advanced biofuel facilities. Efficient and reliable performance from the first commercial advanced biofuel plants would lower the investment risk for replication projects, but greater policy support is also needed, with higher quotas providing guaranteed fuel offtake, and financial de-risking measures are also required. As a result, 60% of planned projects are presumed to be delivered in the accelerated case, resulting in 1 billion L of production by 2023.

Other factors contributing to higher production in the accelerated case include:

- Delivery of India’s ambition to construct 12 advanced biofuel plants.
- Additional capacity in the European Union as the result of a clearly defined role for advanced biofuels in the RED over the 2020-30 period.
- China’s commitment to advancing cellulosic ethanol production.
- Demand from aviation resulting in two additional advanced aviation biofuel plants.
- Ten corn ethanol plants per year in the United States producing cellulosic ethanol from corn fibre.

Biomethane in transport

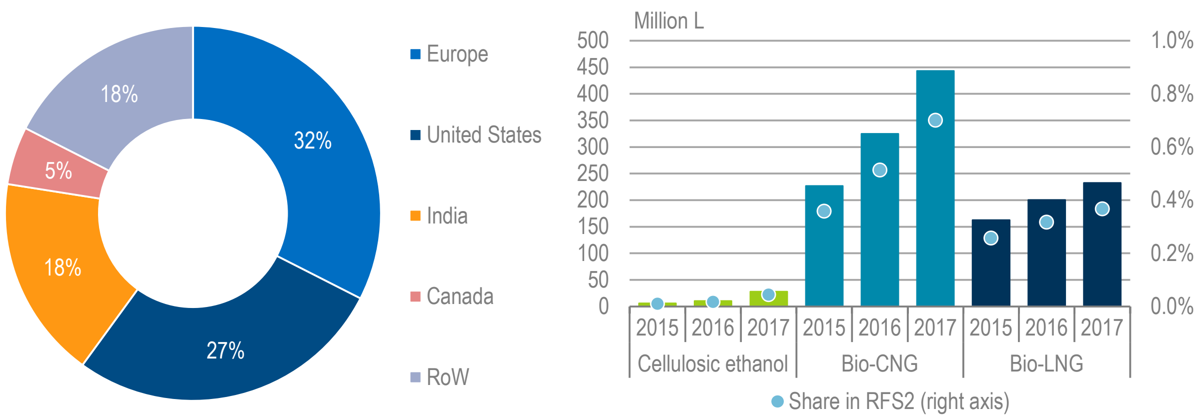
In 2016 the transport sector only accounted for around 1% of biogas demand in final energy consumption globally, with biogas used more commonly for heat and power generation. The use of biomethane for transport is most evident in Nordic countries, especially Sweden, where transport accounted for two-thirds of the biogas share in final energy consumption in 2016. In Denmark there have been some instances of biogas producers switching from electricity generation to biomethane production instead, while in Finland an increasing proportion of new biogas projects are to produce biomethane for transport use.

Biomethane consumption in transport can be expected to increase in Italy owing to a production and distribution subsidy available over 2018-22, as well as France, where the injection of biomethane in natural gas networks increased significantly in 2017 and robust new-project development is evident. Biomethane consumption is also rising in the United States under the RFS2 (Figure 3.6, right) and California's LCFS policies.

Advanced biofuel policy support

Advanced biofuel markets are developing in areas that have established policy mechanisms to foster research, development and deployment. Over three-quarters of announced and under-construction advanced biofuel plants are in the European Union, the United States and India (Figure 3.6, left).

Figure 3.6 Global novel advanced biofuel project development by country (left) and cellulosic ethanol and biomethane consumption in the United States' RFS2 (right)



Notes: Bio-CNG = biomethane as compressed natural gas; Bio-LNG = biomethane as liquefied natural gas. Share per country refers to novel advanced biofuel projects either under construction or announced as of May 2018.

Source: US EPA (2018), *Public Data for the Renewable Fuel Standard*, www.epa.gov/fuels-registration-reporting-and-compliance-help/public-data-renewable-fuel-standard.

In the **European Union**, the provisional agreement for the RED covering the 2020-30 period targets a 14% share of renewable energy in the transport sector's final energy consumption in 2030. As the portion of conventional biofuels will be capped EU-wide at 7%, a significant scale-up in production from a variety of advanced biofuels is required if this target is to be met.

Under the provisional agreement, the use of novel advanced biofuels must expand significantly to meet transport final energy demand shares of 0.2% in 2022, 1% in 2025 and 3.5% in 2030. Biofuels from UCO and animal fat feedstocks are not included in this sub-target and are subject to a cap of 1.7% in 2030. However, the energy contributions of these and other advanced biofuels produced from a range of feedstocks specifically outlined in the updated directive, are eligible to be double-counted towards the overall transport renewable energy target, although this provision rests within the jurisdiction of member states.

To meet the EU-wide targets, Italy, France, Germany, Denmark, Finland and other member states have already either designated mandates or established other supportive policy frameworks for advanced biofuels, with more member states expected to follow. A cluster of cellulosic ethanol producers may develop in south-eastern Europe as a result of lower-cost straw feedstock in the region, as indicated by three production facilities already under construction or in development in Slovakia and Romania.

In the **United States**, policy support is provided by the RFS2, which sets annual compliance volumes for dedicated categories of cellulosic biofuels produced from non-food crops, e.g. advanced ethanol, biodiesel and biomethane fuels. Under the scheme Renewable Identification Numbers (RINs) are awarded per gallon of renewable fuel produced. Obligated parties, refiners and importers of gasoline or diesel must meet their annual quota either by purchasing a combination of renewable biofuels and RINs directly, or by purchasing traded RINs.

Based on certificate prices in the first half of 2018, the cellulosic RIN value for cellulosic ethanol and biomethane fuels equates to USD 0.67/L, compared with an average cost of USD 0.49/L (before tax) for gasoline in 2017. However, despite this support, cellulosic ethanol still accounted for less than 0.1% of all renewable fuels used for RFS2 compliance in 2017, while biomethane reached 1%.

California has the highest motor gasoline consumption of any US state, accounting for 10% of national demand in 2016. It also had the second-highest diesel consumption, claiming 7% of national demand in the same year (US EIA, 2018b). California's LCFS aims to reduce the CO_2 emissions intensity of the transport fuel pool (measured in grammes of carbon dioxide per megajoule [gCO_2/MJ]) to 10% below the 2010 level by 2020, but this targeted reduction level is under review and may be adjusted. The policy has boosted consumption of waste- and residue-based biodiesel and HVO, as well as biomethane, since these renewable fuels emit far less GHGs.

LCFS credits, which each equate to 1 tonne of avoided CO_2 emissions, are awarded to fuels with CO_2 emissions intensities below the annual overall emissions intensity reduction target; traded credits in the first half of 2018 were valued at USD 70 per tonne of carbon dioxide (/tCO_2) to USD 180/tCO_2. Since advanced biofuels emit significantly less CO_2 than fossil fuels, their value per litre under the LCFS is high.

Consequently, LCFS credits for HVO or fatty acid methyl ester (FAME) biodiesel produced from waste and residues can be worth USD 0.20/L (44% of the production cost of fossil diesel), with credits for biomethane at USD 0.17/L (38% of the fossil diesel production cost).[8] Fuel producers can obtain both RFS2 RINs and LCFS credits for the same batch of fuel, making sales to the California market attractive. In addition, US Department of Agriculture loan guarantees support project development.

India approved a new national biofuels policy in 2018 that outlines several measures to support advanced biofuel production, including additional tax incentives, a higher purchase price than for conventional biofuels and investment support of USD 77 million over six years. However, the form this funding will take is currently unspecified.

Fifteen-year offtake agreements between national oil marketing companies and advanced biofuel suppliers have been identified as a key means to provide offtake assurance and therefore facilitate investment in new bio-refineries. It is outlined within the 2018 biofuels policy that advanced biofuels will also benefit from more favourable administratively set purchase prices. Other factors that favour

[8] Based on a credit price of USD 120 and average CO_2 emissions intensity values per fuel type.

advanced biofuel production in India include energy security drivers to limit crude oil imports and the high availability of agricultural residues. Finding alternative uses for such residues is important to limit in-field burning, which deteriorates air quality.

India already has two demonstration-scale advanced biofuel facilities, and its policy framework supports the ambition of national oil marketing companies to commission 12 commercial-scale advanced biofuel refineries. One such project is under construction and four are in development.

Brazil, Japan and the United Kingdom have also developed policy frameworks that should benefit advanced biofuel deployment. It is not anticipated that the RenovaBio programme in **Brazil** will have a dedicated sub-target for advanced biofuels. However, the lower GHG emissions from advanced biofuels compared with conventional biofuels means they will obtain more decarbonisation credits (termed CBIO certificates) for a given volume of fuel under the programme. This could make additional cellulosic ethanol production at sugar cane ethanol facilities more economically attractive.

Trials of new sugar cane varieties (termed ‘energy cane’) are currently underway and indicate up to three times higher biomass yields than standard sugar cane varieties, without compromising sugar content. The additional bagasse produced from energy cane could be used to produce cellulosic ethanol – in fact, if estimated bagasse production for 2023 were increased a further 20% through the rollout of energy cane, the additional feedstock would be sufficient to yield over 15 billion L of cellulosic ethanol from the same amount of land. While promising, this scenario is unlikely to be realised by 2023 because, first, energy cane production is still at the trial stage and, second, the scale of refinery investment needed is considerable.

In **Japan**, cellulosic ethanol is double-counted towards compliance with new energy supply legislation introduced in 2018, and further targets and incentives for cellulosic ethanol production are in development for potential introduction in 2019.

The **United Kingdom**’s RTFO certificate scheme has been extended to 2032, and its renewable-share target has been raised to 12.4% (by volume). The RTFO will offer long-term guaranteed offtake for advanced biofuels under its dedicated sub-target for “development fuels”, which comprise biofuels produced from waste and residue feedstocks. This target is to rise to 1% in 2023 and 2.8% in 2032, and certain waste fuels are double-counted. The obligatory buyout price for each absent development fuel compliance certificate is USD 1/L, although when the double-counting provision is considered it is effectively USD 2/L.

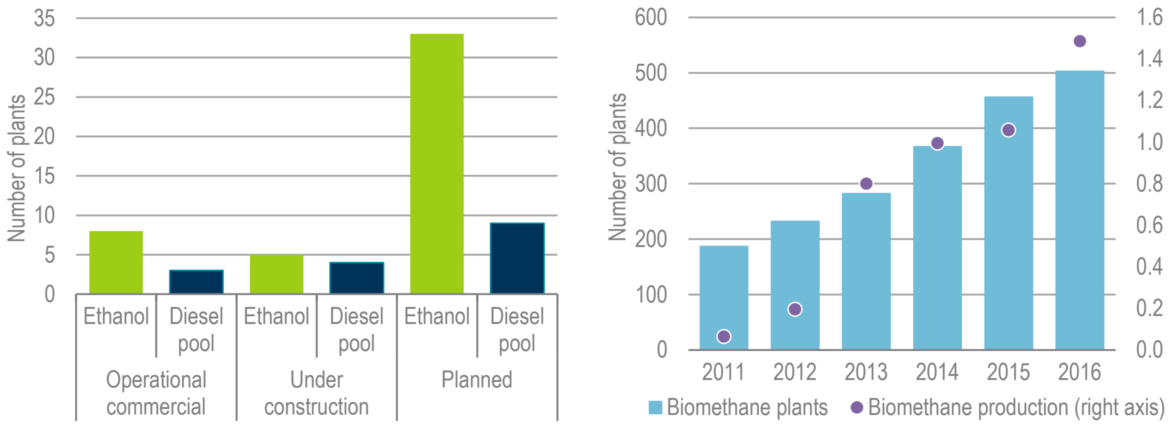
Advanced biofuel feedstocks and technology status

Advanced biofuels can be produced from a range of technologies, each of which is at a different stage of technical development. These technologies also use different feedstocks, the availability of which varies.

FAME biodiesel and HVO produced from waste and residue feedstocks such as used cooking oil and tallow animal fats are technically mature. In the European Union, for example, one-fifth of all biodiesel production came from such feedstocks in 2017, while Neste, the largest global HVO producer, obtained 76% of all feedstocks used for fuel production from waste and residues in 2017.

Increased waste and residue consumption for biofuel production is expected over 2018-23 as a result of favourable policy support. Under the RED, these fuels qualify to have their energy content double-counted towards renewable energy targets. Furthermore, in places where GHG reduction policy frameworks create demand for lower-carbon fuels, e.g. California and Germany, waste- and residue-based fuels benefit from very low CO_2 emissions intensity scores. Consequently, lower volumes of fuel are needed to meet GHG reduction targets. In addition, global HVO capacity is anticipated to increase, potentially by up to 80% over the *Renewables 2018* forecast period, resulting in further demand for waste oils and animal fats.

Figure 3.7 Global novel advanced biofuel plants by fuel type (left) and biomethane market development in the European Union (right)



Notes: Plant status as of May 2018. Biomethane produced is used for heat, electricity and transport applications.

Source: EBA (2017), *Statistical Report 2017*.

Availability of **waste oil and animal fat** feedstocks is ultimately finite, and to mobilise supply to meet increased demand, further technology development and supply chain mobilisation is required. Ongoing technical advances in feedstock pre-treatment to expand the range of suitable wastes and residues are anticipated to be a key means of expanding low-carbon feedstock availability. In places where national supply cannot meet demand, global waste oil and animal fat supply chains may develop. This is already occurring, in fact: around 30% of UCO supplied to the European Union in 2017 was sourced from China (Greenea, 2018). In addition, new food safety regulations in India to limit continued reuse of UCO could also generate additional supplies for biofuel production.

The production of biogas from **organic wastes with high moisture content**, and its subsequent transformation into biomethane for use in natural gas vehicles, is technically mature. In addition, the availability of the range of low-value waste feedstocks suitable for biogas production is high and untapped on most countries. Most biomethane is produced in Europe, which had around 500 plants in 2016 (Figure 3.7, right). However, it should be noted that in addition to transport applications, biomethane can be used for heat and electricity production.

Cellulosic ethanol can be produced from **agricultural residues and woody biomass**, which are readily available in certain countries. However, even though a number of commercial-scale facilities have been commissioned, cellulosic ethanol production is not yet considered technically mature because the performance of these plants has been mixed. Some are currently offline due to a combination of technical and non-technical issues, while others demonstrate ongoing progress and are scaling up output, although production remains below rated capacity. Interest in cellulosic ethanol production is still robust, however, with five plants under construction and further facilities in development (Figure 3.7, left). Plus, the addition of cellulosic ethanol production to conventional corn ethanol plants in the United States is anticipated to grow.

Large-scale production of advanced biofuels from thermochemical processes is not currently taking place, with most facilities at demonstration scale only. Interest remains in such technologies, however, owing to their potential to make use of **woody biomass and municipal waste feedstocks**.

Focus on aviation biofuels

Demand for sustainable aviation fuel (SAF) from the aviation sector is evident, but production remains low: accessing sufficient low-carbon feedstocks and pursuing technological development is necessary to raise production volumes. Aviation biofuels also currently cost more than fossil jet kerosene, so stronger policy support will also be required to facilitate uptake. With enhanced policy support and mobilisation of fuel supply, aviation biofuels could meet 2% of international aviation fuel demand in the medium term.

Strong demand for SAF from the aviation industry

The International Civil Aviation Organization (ICAO) has committed to carbon-neutral growth from 2020 and to reducing CO_2 emissions 50% from the 2005 level by 2050. However, the challenge is to reduce emissions despite increasing aviation activity. Approximately 4 billion passengers took commercial flights in 2017, and it could be close to 5 billion by 2023. Consequently, fuel demand for international aviation bunkers is anticipated to increase 12% to 250 billion L by 2023, while domestic aviation fuel demand is anticipated to grow 8% to 153 billion L.

Using SAF is a particularly important option for decarbonising the aviation industry: in the absence of technology breakthroughs (which are not anticipated), liquid hydrocarbon fuels are the only means of powering long-distance commercial air travel. Therefore, blending SAF with fossil jet fuel has been identified as a key way of ensuring that the ICAO's long-term decarbonisation goals can be met.

To be used in aviation, biofuels must be "drop-in" – i.e. suitable for aircraft use without technical modifications, comply fully with industry standards, demonstrate lifecycle GHG emissions reductions compared with fossil jet fuel, and meet wider sustainability criteria. SAFs can also be beneficial in reducing air pollutant emissions, e.g. sulphur dioxide (SO_2) and particulate matter (PM), improving air quality around major airports.

The aviation industry has demonstrated a strong commitment to using SAF: in 2017, the milestone of over 100 000 flights using aviation biofuel blends was achieved. Currently four airports have regular biofuel distribution (Oslo, Bergen, Stockholm and Los Angeles), with others supplying biofuels on a batch basis. This momentum is expected to continue over the *Renewables 2018* forecast period.

More than ten long-term aviation biofuel offtake agreements between airlines and biofuel producers are currently in place, covering over 1.5 billion L of supply, although the subsequent supply of this volume of aviation biofuels will require further facilities to be constructed (for comparison, current annual jet fuel demand is around 280 billion L). Some airlines have invested directly in SAF refinery projects, and airport initiatives are also in development.

Despite these positive developments, the consumption of biofuels is modest compared with total aviation industry demand, and even with scaled-up consumption this is anticipated to remain the case throughout the forecast period. Although analysis suggests the number of commercial flights using biofuel blends may surpass 1 million around 2020, there were 36.8 million commercial flights in 2017. In addition, the International Air Transport Association (IATA) has set a goal of 1 billion passengers having flown on flights powered by SAF blended with fossil jet fuel by 2025, but given expected civil aviation activity, this equates to only one in every 42 000 passengers in the period up to the end of 2025.

Economics of aviation biofuel consumption

Aviation biofuels are currently more expensive than fossil jet fuel, and this cost premium is a key barrier to their uptake. Fuel is the single largest overhead expense for airlines and accounts for up to 30% of operational costs. Consequently, the aviation industry is not in a position to cover significant cost premiums to utilise aviation biofuels. While airlines purchase aviation fuels, the cost premium of SAFs may need to be shared more widely through mechanisms that spread additional costs among airlines, airports, government and passengers.

The additional cost of biofuels depends on a range of factors. For fossil jet kerosene, crude oil price is the primary determinant of cost. At a crude oil price of around USD 100 per barrel (/bbl), fossil jet kerosene was roughly USD 0.65/L, dropping under USD 0.35/L at USD 50/bbl. The influence of oil price is amplified because jet kerosene for international aviation is virtually untaxed.

For aviation biofuels, a wider range of considerations, including the technology and feedstock used, affect cost. Five aviation biofuel production pathways currently meet industry specifications and are approved for blending with fossil jet kerosene. However, only one – hydroprocessed esters and fatty acids synthetic paraffinic kerosene (HEFA-SPK) fuel – is currently technically mature and commercialised. Therefore, because of its higher availability and lower production costs compared with other aviation biofuels, HEFA-SPK is anticipated to be the principal biofuel used in aviation during the forecast period.

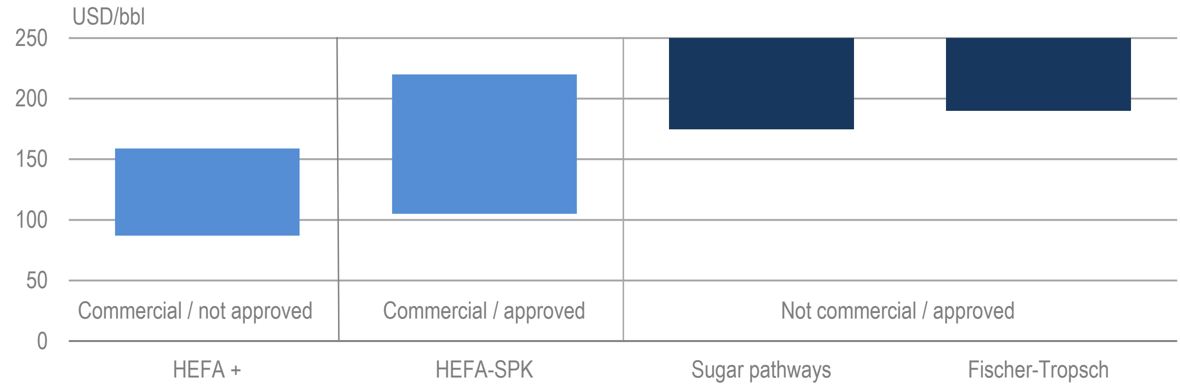
HEFA-SPK production technology is broadly mature, with limited scope to reduce costs through technical learning. However, only one facility currently produces HEFA-SPK continuously; others produce it on a batch basis. However, batch production incurs higher production costs and operational disruption. Production costs could therefore be reduced through refineries designed for continuous HEFA-SPK production that benefit from economies of scale.

HEFA+, a fuel with a quality specification similar to HVO used in road applications, could be approved for use in aviation by late 2018. The maximum permitted blend level for HEFA+ would be 15%, as opposed to blends of up to 50% approved for higher-grade HEFA-SPK. The approval of HEFA+ could increase the consumption of SAFs during the forecast period, since it is anticipated to have a lower cost premium than HEFA-SPK compared with fossil jet kerosene, and higher availability since it could be produced at existing HVO facilities (Figure 3.8).

As with other biofuels, feedstocks are the major determinant of HEFA production costs, so obtaining an economically competitive feedstock supply is fundamental to minimise cost premiums over fossil jet kerosene. Oil crop feedstocks are technically suitable for use and have relatively high availability. However, there is caution within the aviation industry relating to the ongoing sustainability debate around the use of certain crop oils. This has led to interest in non-food oil crop feedstocks, which can be grown either between regular crop cycles or on marginal land.

Lower-carbon waste oils and animal fats are likely to be of primary interest to the aviation industry, as they deliver more significant GHG emissions reductions than oil crop feedstocks do, and they are uncontroversial in terms of land use change. Demand for these feedstocks increases in places where GHG emissions reduction policies are in place, and they are already widely used for biodiesel and HVO production for road transport.

Figure 3.8 Break-even crude oil prices for different aviation biofuel production pathways



Notes: USD 250/bbl does not represent the current upper limit of break-even crude oil price for sugar and Fischer-Tropsch pathways. Sugar pathways refers to fermented sugars-to-synthetic isoparaffin (HFS-SIP) and alcohol-to-jet (ATJ) technologies.

Rising demand has the potential to inflate feedstock prices and limit the potential for HEFA cost reductions. Therefore, ongoing investment in pre-treatment research and development to widen the portfolio of suitable feedstocks is necessary to ensure that their additional consumption in the aviation sector can be sustained and that their costs remain competitive.

The best prospects for delivering competitively priced HEFA over the forecast period are either an increase in the price of crude oil or policy support measures to cover cost premiums. Current prices for waste oil and animal fat feedstocks are USD 500/tonne to USD 800/tonne, and the significant cost reductions needed to deliver HEFA-SPK cost parity with fossil jet fuel at a crude oil price of USD 70/bbl is considered unlikely (Table 3.6).

Table 3.6 Alternative conditions for HEFA fuels to be competitive with fossil jet kerosene

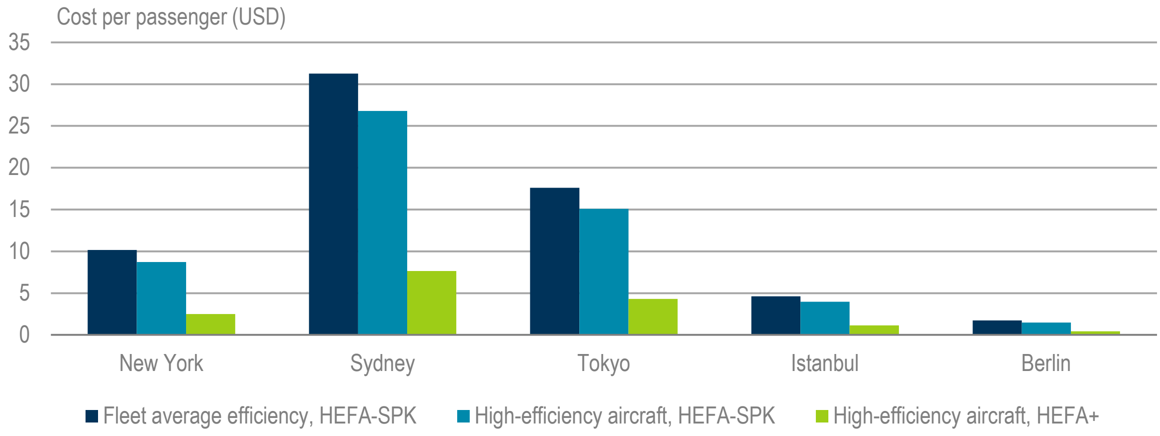
	Minimum crude oil price (USD/bbl)	Required feedstock price (USD/tonne)	Policy support (USD/L)	Carbon price (USD/tCO_2)
HEFA-SPK	110	350	0.35	150
HEFA+	90	500	0.10	45

Note: Each condition could deliver competitive HEFA in isolation; all four together are not required.

Feedstock availability is also a factor. While HEFA is the only commercially produced aviation biofuel, the contribution of SAFs to aviation demand could be restricted by competing demand for the lowest carbon waste oil and animal fat feedstocks e.g. from road transport biofuel production, if very stringent decarbonisation requirements are set. It is therefore important not to overlook the potential of other feedstocks that, although they may offer lower emissions reductions, have higher availability and could deliver higher aviation emissions reductions overall if widely used.

In the long term, the aviation industry may seek to include additional SAF blending expenses within service costs. At current HEFA prices, the additional cost per passenger for a 15% blend of HEFA may not be prohibitively high in comparison with other elements that influence ticket prices, such as seating class or time of ticket purchase (Figure 3.9). This may make it easier for corporate social responsibility programmes to facilitate aviation biofuel consumption; there is already an example of this in the SkyNRG Fly Green Fund in Nordic countries.

Figure 3.9 Additional cost per passenger for a one-way flight from London to selected destinations with 15% HEFA blends



Status of aviation biofuel policy support

Without enhanced policy support, the aviation industry is unlikely to be able to significantly scale up SAF consumption over the next five years. Policies that could support higher consumption include:

- Financial de-risking measures for refinery project investments (e.g. grants, loan guarantees).
- Incentives for airlines to consume SAFs that close the cost premium with fossil jet kerosene.
- Measures to provide guaranteed SAF offtake, e.g. mandates, targets and public procurement.

To gain the confidence of policy makers and the general public, policy support will most likely need to be linked to robust fuel sustainability criteria.

Policy support for biofuel consumption in road transport is currently more widespread than for aviation. In addition, the higher fuel quality requirements, production costs and stringent approval processes for aviation biofuels make road transport biofuels more attractive. Adjusting policies to make conditions equally favourable for the aviation sector is therefore necessary to attract the investment required to boost aviation biofuel output. This is especially relevant because biodiesel or HVO fuels for road transport can use the same feedstock sources as HEFA for aviation.

The CORSIA, scheduled to be introduced in 2021, will be the principal mechanism used to meet the ICAO's long-term decarbonisation targets. Initially the scheme will be voluntary, but approximately 70 countries representing almost 90% of international aviation activity have confirmed their participation.

SAF consumption and the purchase of carbon offsets are the two principal means to achieve compliance, but the attractiveness of these to the aviation industry will depend on their cost per tCO_2 of emissions mitigated. Current abatement costs of aviation biofuels per tCO_2 are notably higher than voluntary offset credit prices. Should this remain the case, the short-term stimulus of the CORSIA for aviation biofuel deployment may be limited. That said, the offset requirements to be used under the CORSIA are still in development, so it is not yet possible to assess the offset credit costs relative to SAF prices.

Countries have more control over policy support for domestic aviation than they do for international aviation,[9] and the introduction of national policy mechanisms incorporating aviation is gathering pace. In the United States, aviation biofuels can receive RIN credits under the RFS2, aviation biofuels are now included in the United Kingdom's RTFO and the Netherlands has a 'bio-tickets'[10] scheme for aviation. Further policy measures are also on the horizon: the eligibility of SAFs to generate credits under California's LCFS is under consideration; Norway is considering a blending mandate for renewable jet fuel starting in 2019; and Sweden's aviation sector aims to be fossil fuel-free by 2045.

Aviation is included within the EU emissions trading scheme for flights within the European Economic Area; however, certificate prices are currently too low to stimulate SAF uptake. Within the provisional agreement for the updated RED for 2020-30, renewable aviation biofuels benefit from a 1.2x multiplier of their energy content towards RED targets, although there are contrasting views on whether this will be sufficient to stimulate significant uptake.

What share of international aviation fuel demand could biofuels supply by 2023?

To achieve the ICAO's long-term decarbonisation commitments, a vision for alternative aviation fuels was outlined in 2017. Although not adopted as an official target, the vision outlined that meeting 2% of international aviation jet fuel demand by 2025, alongside improved energy efficiency, would keep aviation on the path to accomplish its CO_2 emissions reduction objectives (ICAO, 2017).

Supplying 2% of international aviation fuel demand by 2025 equates to 5 billion L of SAF. In the absence of other commercialised SAF production processes, delivering this volume would require an increase in HEFA-SPK production capacity. If met by new facilities only, approximately 20 refineries would be required in the period up to 2025.[11] While the associated investment would be significant, it is small compared with current annual fossil fuel refinery investments (Table 3.7).

Table 3.7 Biofuel volumes and investment to meet 2% of international aviation fuel demand

2025 estimated international aviation fuel demand (billion L)	Volume of HEFA-SPK to meet 2% of demand (billion L)	Greenfield HEFA-SPK refinery investment 2017-25 (USD billion)	Estimated annual fossil fuel refinery investment in 2017 (USD billion)
260	5.2	8-10	60

Source: IEA (2018d), *World Energy Investment 2018*.

The repurposing of existing fossil fuel refineries to produce HEFA and HVO can be undertaken with half the investment needed for new-build plants. Therefore, if a portion of new HEFA aviation biofuel production capacity were provided through refinery renovations, the investment needed would be significantly lower. In addition, commercialising the co-processing of crude oil and bio-crude in oil refineries could raise renewable jet fuel output from existing facilities.

9 Emissions from domestic aviation fall under the COP21 global climate agreement, while those from international aviation do not.

10 Bio-tickets awarded to aviation biofuel producers can be bought by obligated parties in the road transport sector to fulfil EU RED targets.

11 Assuming that each refinery dedicated around half of its product slate to HEFA-SPK. The product or refinery slate refers to the desired range of products to be produced and their quality.

Prospects for refinery investment to increase HEFA production are also linked to demand for other products. As HEFA is only one of a range of products produced at a refinery, the question of whether to invest in new facilities should also consider the future demand prospects for the full range of products to be produced.

Should HEFA+ be approved, the amount of HEFA aviation fuel that could be produced using existing HVO production capacity could be increased. HVO capacity is likely to reach 9 billion L over the forecast period, but for HEFA fuels to command a significantly larger share of output from these facilities, the market context will need to change to make the production of aviation fuels more attractive relative to that of road transport fuels.

Regardless of the source of production capacity, meeting 2% of international aviation demand from SAFs will require strong demand signals from the aviation industry, with airlines stepping up forward-purchasing of aviation biofuels through offtake agreements. This in turn will depend on the successful implementation of the CORSIA along with CO_2 emissions mitigation costs of aviation biofuels that are competitive with carbon offset prices within the scheme, as well as more widespread national policy measures for SAF utilisation.

It will also be important for airports to bring together various stakeholders such as airlines, fuel suppliers and government representatives to co-ordinate scaled-up SAF use. This may also facilitate the sharing of renewable fuel cost premiums among different stakeholders.

For SAFs to account for a significant share of aviation fuel demand in the long term, commercialisation of other approved technologies (e.g. Fischer-Tropsch and alcohol-to-jet) will be necessary to unlock the potential to use greater volumes of low-carbon feedstocks, such as forestry biomass and municipal solid wastes, which are more abundant and cost less than waste oils and animal fats. Ongoing research and development will therefore be important in supporting commercialisation of a wider array of aviation biofuel production technologies. Two aviation biofuel plants using Fischer-Tropsch technology are currently under construction in the United States.

In scaling up SAF consumption, pipeline access and downstream logistics also need to be considered. SAF utilisation will be aided by the centralised nature of aviation fuelling: as fewer than 5% of airports handle 90% of international flights, integrating SAFs at a relatively small number of airports could cover a large share of demand.

Air quality implications of transport biofuel consumption

Many countries have initiated policy support for biofuel consumption to reduce transport sector CO_2 emissions. However, transportation is also a key contributor to urban air pollution, which is a pressing issue in many large cities. How biofuels compare with fossil fuels in terms of air pollutant emissions that negatively affect human health is therefore a key consideration in their use.

To understand the impact of biofuels on air pollutant emissions from road vehicles, there are two determining factors to consider: first, the combination of the vehicle's engine and exhaust aftertreatment technology;[12] and second, the characteristics of the biofuel compared with the fossil fuel being replaced. Taken together, these two components provide an indication of the performance of biofuels relative to fossil fuels in terms of air pollutant emissions and impact on human health.

[12] Also referred to as emissions control technology.

Air pollutant emissions from road transport and their impact on human health

Road vehicle exhaust emissions contain an array of pollutants that negatively impact human health. Many of these can be grouped under the following categories:

- Nitrogen oxide compounds (NO_X): Within this category, nitrogen dioxide (NO_2) is generally the most damaging to health, as it irritates the respiratory tract and after long-term exposure can lead to reduced lung function, chronic cardiovascular diseases and lung cancer.
- Volatile organic compounds (VOCs): This category comprises volatile hydrocarbons and carbonyl compounds. VOCs such as 1,3-butadiene, benzene and formaldehyde are classified as carcinogenic, while acetaldehyde is classified as potentially carcinogenic. VOCs may also irritate the skin, eyes and respiratory tract, and induce cellular inflammation.
- Particulate matter (PM): This grouping includes ultrafine particles, black carbon and associated compounds, e.g. polyaromatic hydrocarbons (PAHs). Health effects of PM relate to particle size and composition. Diesel PM is classified as carcinogenic to humans. PM has also been linked with heart, pulmonary and Alzheimer's disease.

Other transport-related air pollutants that can also damage human health include carbon monoxide (CO) and products formed from chemical reactions involving the emissions listed above.

Influence of engine type and aftertreatment technology on air pollutant emissions

With sophisticated engines and aftertreatment technology, the effect of a fuel's chemical and physical characteristics on tailpipe emissions is greatly reduced. For vehicles that comply with the latest emissions standards,[13] most tailpipe air pollutant emissions reach very low levels regardless of the fuel used. For older vehicles, however, fuel type can significantly influence air pollutant emissions. Therefore, fuel selection is particularly relevant in many emerging economies and developing countries with large urban agglomerations and older vehicle fleets.

Vehicle engine type also determines the exhaust aftertreatment technology that can be used. Spark-ignition engines can use gasoline, ethanol or, with small modifications, methane (e.g. natural gas or biomethane), and air pollutant emissions from spark-ignition engines can be reduced to very low levels through a three-way catalyst (TWC). In contrast, diesel engines require a more complex and expensive system that includes a particulate filter and a selective catalytic reduction catalyst to control emissions. In addition, maintaining the high exhaust temperatures needed for proper catalyst operation is more challenging for diesel than spark-ignition engines.

How does biofuel consumption alter air pollutant emissions compared with fossil fuels?

The air-pollutant emissions impacts of ethanol and biomethane as substitutes for gasoline and of FAME biodiesel and HVO as diesel substitutes are outlined below:

- **Ethanol** generally results in lower air pollutant emissions when blended with gasoline, with the level of emissions falling as the share of ethanol rises. This improvement is especially notable for PM, wherein lower emissions from high-ethanol blends are achieved with direct-injection spark-ignition engines. Ethanol also reduces tailpipe CO emissions; however, cold starting is more challenging with E85 than with gasoline, potentially raising VOC emissions, and higher ethanol blends can increase acetaldehyde emissions compared with gasoline.

[13] Examples include Euro 6 in Europe and US Tier 3. Sophisticated engines discharge less than 5% the air pollutant emissions of less sophisticated or uncontrolled engines.

- **Biomethane** delivers low CO, PM and VOC emissions when used in a spark-ignition gas engine. NO_x emissions vary significantly depending on engine and exhaust aftertreatment technology; they are low for engines with a properly functioning TWC and higher for less sophisticated lean-burn gas engines, for which there is some evidence of elevated formaldehyde emissions.

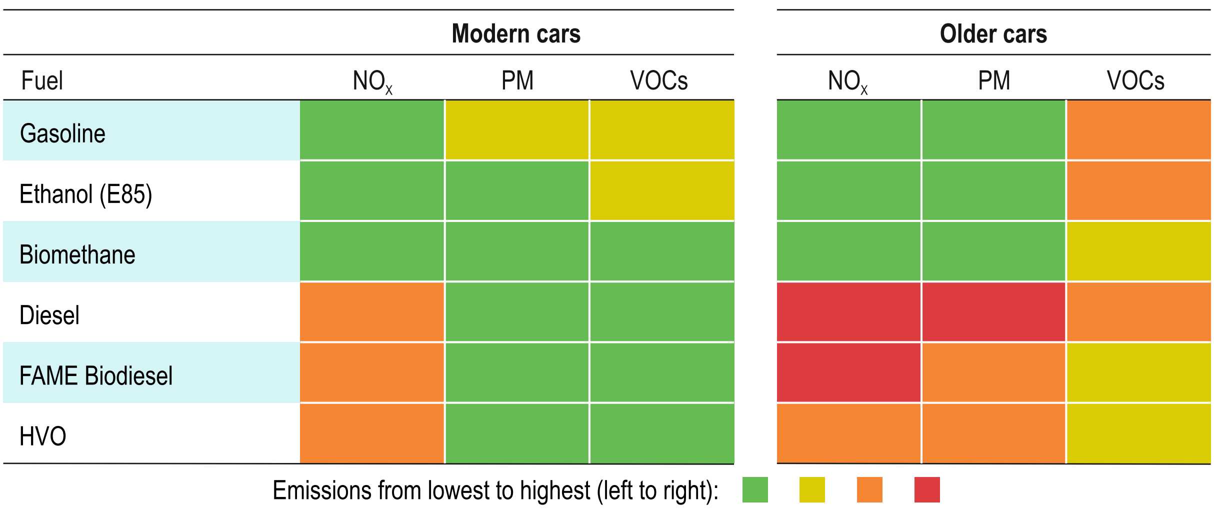
- **FAME biodiesel** used at high blend levels decreases CO, VOC and PM emissions, potentially up to 50% in less sophisticated engines. However, at high blends FAME increases NO_x emissions compared with fossil diesel as a result of higher oxygen content and subsequently higher combustion temperatures.

- **HVO** has high ignition quality and the paraffinic nature of the fuel improves combustion and thus reduces CO, hydrocarbon and PM emissions compared with regular diesel. Unlike FAME biodiesel, HVO also has potential to reduce NO_x emissions up to 10%. Of all fuels suitable for use in diesel vehicles, HVO delivers the lowest exhaust mutagenicity.

Net effect of biofuel consumption on air pollutant emissions

The IEA's 'Advanced Motor Fuels' technology collaboration programme (TCP) compared the emissions of various fuels by category of air pollutant. For cars with less sophisticated engines, air pollutant emissions are higher from diesel engines than from spark-ignition (gasoline) engines (Table 3.8). With cars that meet the equivalent of a Euro 3 emissions standard, e.g. manufactured around the year 2000 in Europe, biomethane has the most potential to deliver low air pollutant emissions.[14]

Table 3.8 Air pollutant emissions by fuel from modern and older cars



Notes: Older = Euro 3 or equivalent (e.g. model year 2000 in Europe); modern = vehicles that meet Euro 6 emissions standards or equivalent. Assessing the relative performance of biofuels compared with fossil fuels in terms of air pollutant emissions, and therefore health impact, is complex. Consequently, ranking different fuels according to health impact can be subject to debate because biofuels can decrease some air pollutant emissions compared with fossil fuels while increasing others. Consideration must also be given to the fossil fuel substituted, how the biofuel is consumed, e.g. blended (at a low or high share) or unblended, and the level of sophistication of the vehicle's engine and aftertreatment technology. In addition, the relative health risks of different air pollutants must also be taken into account. PM categorisation for modern cars is made on the basis that direct injection gasoline engines have higher PM emissions than particulate filter-equipped diesel cars.

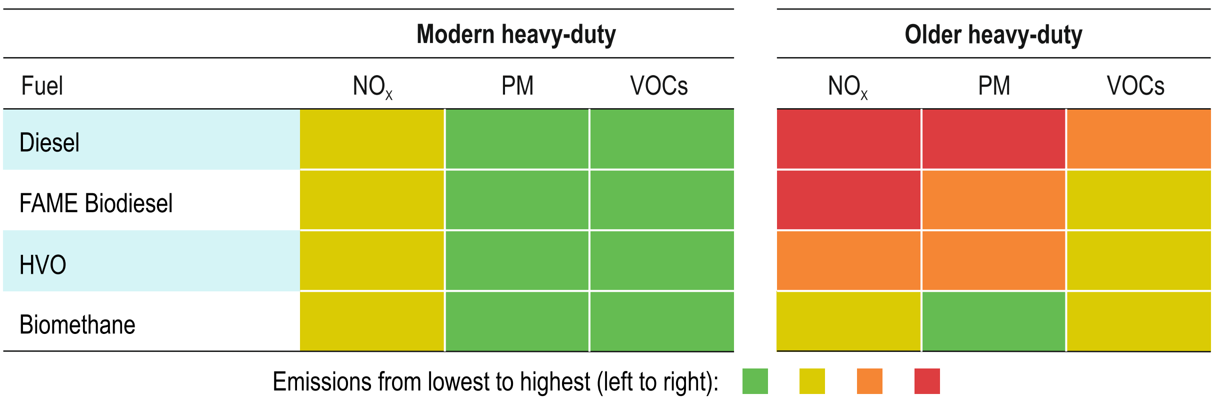
[14] Gasoline vehicles can be converted to use natural gas/biomethane. However, qualified retrofitting companies and robust testing are required to verify performance.

E85 blends can deliver lower PM emissions than fossil gasoline in older cars, but the reduction is relatively minor. For more widely consumed low-ethanol blends, e.g. E10, the effects on air pollutant emissions are less pronounced than for higher blends, although in older engines without catalysts, E10 can reduce CO and VOC emissions to a small extent. In catalyst-equipped cars the impact of ethanol blending on emissions is minor.

In modern cars, biomethane again delivers the lowest emissions, while ethanol in high blends can reduce PM emissions compared with gasoline for cars with direct injection engines. For older diesel engine cars, FAME biodiesel and HVO generally improve air quality compared with fossil diesel. FAME biodiesel results in higher NO_X emissions than HVO, however. In modern diesel cars, fuel type has a minimal effect on air pollutant emissions.

For heavy-duty vehicles, diesel engines are currently standard. Old heavy-duty engines exhibit pronounced differences in air pollutant emissions depending on the fuel (Table 3.9). Conversely, new heavy-duty vehicles meet the highest emissions standards and have low air pollutant emissions regardless of the fuel used. FAME and HVO can reduce air pollutants from older engines (e.g. Euro 3 standard or equivalent), while biomethane vehicles perform best in terms of reduced air pollutant emissions compared with fossil diesel.

Table 3.9 Air pollutant emissions by fuel from modern and older heavy-duty vehicles



Note: Please see note below Table 3.8.

Given the composition of vehicle fleets over the *Renewables 2018* forecast period and beyond, the ability of biofuels to reduce air pollutant as well as CO_2 emissions could drive policy support for their use. This is especially the case in countries with pressing air quality concerns due to older vehicle fleets (or lax emissions standards for new vehicles) and large urban agglomerations.

Generally, low-income and lower-middle-income countries tend to have a higher vehicle scrappage age than higher-income countries. In addition, in many countries and regions (e.g. Africa, Eastern Europe and Mexico), imports of older, used vehicles that perform poorly in terms of air pollutant emissions than modern equivalents are also prevalent.

Air quality benefits from biofuel use may be particularly attainable in countries such as India, Indonesia and Thailand, which have a higher average age for vehicle scrappage and domestic biofuel consumption policies (Table 3.10). Since the relative improvement in air pollutant emissions is greater for diesel than for gasoline vehicles, a further consideration in terms of emissions reductions is the predominant fuel type used by the passenger vehicle fleet. For instance, less than 15% of Argentina's car fleet is diesel-fuelled (Vassallo, 2018), but diesel power trains command a higher market share in India; for heavy-duty vehicles, diesel is used almost exclusively worldwide. Furthermore, gasoline and diesel fuel specifications (e.g. regarding permissible sulphur content) also influence air pollutant emissions in vehicles built to less stringent emissions standards.

Table 3.10 Estimated average scrappage age of passenger and heavy-duty vehicles (years)

	Passenger cars	Heavy-duty vehicles
European Union	10 - 15	10 - 15
United States	16 - 20	10 - 15
Argentina	10 - 15	16 - 20
Brazil	16 - 20	16 - 20
Mexico	>25	21 - 25
India	21 - 25	21 - 25
Indonesia	21 - 25	21 - 25
Thailand	16 - 20	10 - 15

Note: Estimates based on 2015 market data.

Source: IEA (2018a), Modelling of the Transport Sector in the Mobility Model (MoMo), July 2018 version.

Regulations regarding permissible levels of air pollutant emissions for new vehicles and robustness of emissions testing practices, e.g. real-world testing conditions, are also valid factors in determining whether biofuels could offer benefits in terms of lowering air pollutant emissions.

Table 3.11 Euro emissions standards for NO_x and mass of particles (g/km) for passenger cars

	Gasoline		Diesel	
	NO_X	Mass of particles	NO_X	Mass of particles
Euro 1	0.97[1]	-	0.97[1]	-
Euro 2	0.50[1]	-	0.90[1]	-
Euro 3	0.15	-	0.50	-
Euro 4	0.08	-	0.25	-
Euro 5	0.06	0.0045[2]	0.18	0.0045
Euro 6	0.06	0.0045[2]	0.08	0.0045

Notes: 1 = expressed as HC + NOx; 2 = applicable to direct injection gasoline engines only. Euro 6 introduced limits for ultra-fine particles for direct injection gasoline engines that were not in place for Euro 5.

Source: ACEA (2018b), "Euro standards", www.acea.be/industry-topics/tag/category/euro-standards.

In the European Union, Euro 6 standards became mandatory for new registrations as of September 2015, but new vehicles are not produced to such stringent standards globally. Argentina instituted a Euro 5 emissions standard-equivalent for both light- and heavy-duty vehicles in 2016, while in 2017 India required Euro 4-equivalent standards nationwide.[15] Indonesia plans to upgrade from far less stringent Euro 2-equivalent standards for new gasoline vehicles in 2018, but for diesel vehicles it will

[15] India's standards are termed "Bharat Stages"; stage 4 norms were introduced in selected cities in 2010.

take until 2021. Biofuels could therefore continue to play a role in reducing air pollutant emissions in these and other countries with less robust emissions standards for years to come.

For modern vehicles that comply with the latest emissions standards,[16] the difference in air pollutant emissions between biofuels and fossil fuels is minimal. Therefore, in the long term, the transition to sophisticated internal combustion engine vehicles and to battery electric light-duty passenger vehicles that do not emit tailpipe air pollutants weakens the case for biofuels as a means to improve air quality. However, their potential to reduce CO_2 emissions means sustainable biofuels will still be useful in the long-term decarbonisation of the transport sector, especially for long-distance heavy-duty trucking, aviation and marine transport.

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[16] For example, Euro 6 with compliance demonstrated by testing under real-world driving conditions, as is now required in Europe.

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4. RENEWABLE HEAT

Highlights

- Heat accounts for the largest portion of end-use energy: over half of total final energy consumption is for heating buildings and water, and for cooking, drying and industrial processes. Most heat is generated from fossil fuels, and while renewable heat production has increased in recent years, excluding the traditional use of biomass, only 10% of heat consumed in 2017 was renewable. Energy efficiency plays a key role in reducing GHG emissions from heat production.
- Modern bioenergy produced almost 90% of direct renewable heat in 2017 and most of the renewable heat used in district heating. Bioenergy penetration is higher in industry than in buildings. In 2017, bioenergy met 7% of industrial heat demand, with most consumption in subsectors that produce solid biomass waste and residues on-site. Bioenergy consumption is largest in pulp and paper production, where it met almost 30% of energy demand in 2017.
- Bioenergy contributes the highest absolute growth in renewable heat consumption during the outlook period (2018-23), although other renewable sources are anticipated to grow at a faster rate. Industrial bioenergy consumption is expected to grow 13% by 2023. In the cement sector, projected growth of almost 40% raises the share of bioenergy from 5% of the sector's energy demand to 7%.
- There is significant untapped potential to increase bioenergy use in the cement subsector and the sugar and ethanol industry. Around two-thirds of bioenergy used in cement production is from waste. Therefore, the application of robust waste management frameworks in key cement-producing countries could increase bioenergy's share of cement energy demand to 13% by 2023. Renewable energy generation from the sugar and ethanol industry could be significantly increased if all sugar cane-cultivating countries exploited the potential of high-efficiency co-generation, sugar cane straw and new energy cane varieties.
- Renewable electricity for heat is expected to have the second-largest absolute growth over the outlook period because: 1) the share of renewables in electricity generation is expanding and 2) the use of electricity in heat production is increasing more quickly than total heat consumption. The total use of electricity for heat is expected to grow 20% in the industry sector and 11% in buildings. Heat pumps, mostly powered by electricity, are being increasingly deployed, especially in buildings: sales doubled from 2012 to 2017, with 4 million units sold globally in 2017, mostly in the People's Republic of China,[1] the European Union and Japan.
- Global buildings sector renewable heat consumption rose 25% in the 2012-17 period mainly as a result of rapid growth in solar thermal and geothermal deployment in China, as well as a significant expansion of bioenergy and renewable electricity for heat in the European Union. Consequently, China has overtaken the United States as the largest single-country consumer of renewable heat in buildings. Global growth over the outlook period is led by renewable electricity for heat and solar thermal generation.
- Policies for renewable heat are less widespread than for renewable electricity, although deployment has been rapid where effective policies exist. For example, renewable heat consumption grew 120% in 2012-17 in China, which has ambitious renewable heat targets. Further growth of 44% is expected over 2018-23 to meet the targets of China's 13th Five-Year Plan. In the European Union, the revised Renewable Energy Directive (RED) is expected to drive continued renewable heat growth over the outlook period.

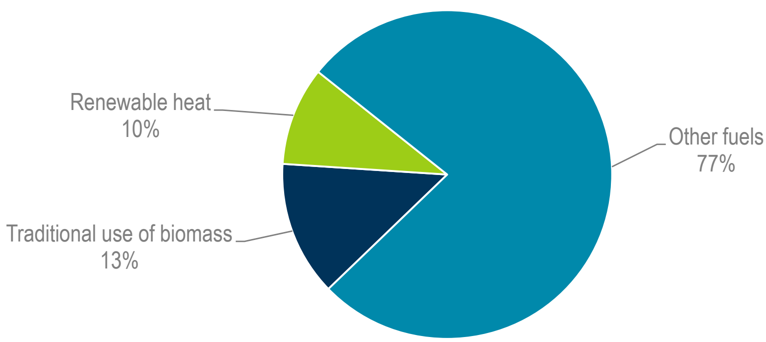
[1] Hereafter "China".

Global overview and outlook

In 2017, almost 5 000 million tonnes of oil equivalent (Mtoe) of final energy consumption was for heat, of which over 660 Mtoe was generated from the traditional use of solid biomass. Just over 50% of heat produced was consumed in industry, for example for process heat, drying and industrial hot water uses. Another 46% was used for space and water heating and cooking in the buildings sector while the remainder was used in agriculture for heating and drying purposes.

Most heat continues to be produced from fossil fuels, with only 10% from renewable energy sources (Figure 4.1). As a result, heat consumption contributed almost 40% of energy-related carbon dioxide (CO_2) emissions in 2017 (12.6 gigatonnes of CO_2 [$GtCO_2$]). To reduce these emissions, as well as remedy other related problems such as local air pollution, a strategy that combines energy efficiency improvements with switching to renewable and other low-carbon heat sources (e.g. excess heat) is necessary.

Figure 4.1 Fuel shares in global heat consumption, 2017



Sources: IEA (2018d), *World Energy Statistics and Balances 2017* (database), www.iea.org/statistics/; IEA (forthcoming), *World Energy Outlook 2018*.

Renewable heat[2] consumption grew 18% in 2012-17, and it is expected to grow more quickly over the outlook period, increasing to 20% as deployment in key markets accelerates (Table 4.1). Two-thirds of global renewable heat growth is expected to take place in China, the European Union, the United States and India, which are already the largest consumers of renewable heat (Figure 4.2).

In the **European Union**, the RED has driven the uptake of renewable heat, with growth of 25% over 2012-17. Expansion is expected to be somewhat slower over the outlook period (15%) and is more rapid in the buildings sector (18%) than in industry (10%). However, as a new EU target for renewable heat has recently been established, growth could be faster depending on how member states decide to implement it. At the same time, energy efficiency improvements have reduced overall heat demand in the European Union slightly, with a 0.3% drop in 2012-17 and a further 2% reduction expected over 2018-23. This makes the European Union the only region in which heat demand is falling rather than increasing.

In the **United States**, currently the single country with the greatest renewable heat consumption, consumption is projected to rise 20% over 2018-23. Three-quarters of this growth is expected in the

[2] This definition of renewable heat used in this report excludes the traditional use of biomass. It covers direct and indirect (i.e. district heating) final consumption of bioenergy, solar thermal energy and geothermal energy. It also includes renewable electricity for heat, based on an estimate of the amount of electricity used for heat production and the share of renewables in electricity generation.

buildings sector, with the use of renewable electricity for heat demonstrating the largest absolute increase, driven by electrification. Solar thermal energy use in buildings is expected to rise almost 70% (although from a small base) owing to tax credits available until 2022, followed by 18% higher bioenergy use.

Table 4.1 Global trends and outlook for renewable heat, 2010-23

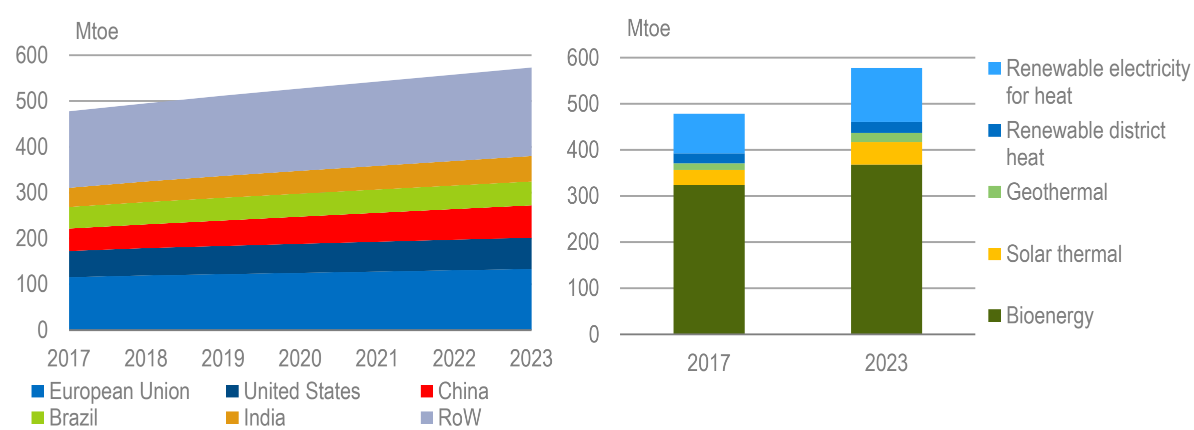
	2017 estimates (Mtoe)	Share of total, 2017	Growth 2012-17	Growth 2018-23	CAAGR 2018-23
Total energy consumed for heat	4 945	N/A	4%	7%	1.1%
Total modern renewables for heat	478	10%	18%	20%	3.1%
Of which: Renewable district heat	22	5%	31%	11%	1.7%
Modern bioenergy	323	68%	9%	12%	1.9%
Solar thermal	33	7%	82%	46%	6.5%
Geothermal	14	3%	89%	44%	6.3%
Renewable electricity for heat	86	18%	33%	38%	5.5%

Notes: CAAGR = compound annual average growth rate; N/A = not applicable. All figures for heat correspond to final energy consumption in the buildings, agriculture and industry sectors; heat produced from renewable district heat in 2017 was 95% bioenergy. Total energy consumed for heat includes energy used in blast furnaces.

Sources: IEA (2018d), *World Energy Statistics and Balances 2018* (database), www.iea.org/statistics/; IEA (forthcoming), *World Energy Outlook 2018*.

The ambitious renewable heat targets of **China**'s 13th Five-Year Plan and supporting policies are expected to result in growth of 44% over 2018-23. While this is lower than in the 2012-17 period, China is forecast to overtake the United States as the largest single-country consumer of renewable heat by 2022. Growth in solar thermal slows, but it accelerates for bioenergy. In fact, bioenergy in industry demonstrates the greatest absolute growth, an additional 7.3 Mtoe.[3]

Figure 4.2 Renewable heat consumption by country/region (left) and by source (right)



Note: RoW = rest of world. Sources: IEA (2018d), *World Energy Statistics and Balances 2017* (database), www.iea.org/statistics/; IEA (forthcoming), *World Energy Outlook 2018*.

[3] China does not currently report any renewable heat use in industry in its statistics, although some bioenergy use is likely.

India's renewable heat consumption is expected to increase one-third over the period 2018-23. Most of the growth results from industry's increased use of bioenergy. There is also some growth in solar thermal and renewable electricity-generated heat, albeit from a small base.

Of the major renewable heat consumers, **Brazil** exhibits the lowest growth over the outlook period due to continued sluggish economic performance. The projected 10% increase in renewable heat consumption results mainly from growth in heat produced from solar thermal installations and renewable electricity in the buildings sector.

Elsewhere, renewable heat consumption remains very low in the **Russian Federation**, one of the world's larger heat consumers. Due to the absence of policies to support renewable heat, its share is expected to remain at around 2.5% of total heat consumed over the outlook period. Meanwhile, in **Indonesia**, even though the amount of renewable heat consumed grows 18%, the share of renewable heat remains low in 2023 at 7.4%. Across much of **Africa**, heat consumption continues to be dominated by traditional biomass use, which rises due to population pressures.

In terms of sources, bioenergy currently dominates renewable heat consumption, accounting for almost 90% of direct renewable heat use and most renewable heat in district heating schemes (Table 4.1). Although growth in bioenergy is slower than for other renewables over the 2018-23 period, 13% in industry and 9% in buildings is still projected.

Recent policy developments

Policies for renewable heat tend to be less dynamic than for renewable electricity. In 2017, 52 countries had renewable heat policies, compared with 121 for renewable electricity and 76 for renewable transport. These figures have remained fairly constant in recent years, while the number of countries implementing renewable electricity policies has grown continuously. Energy efficiency policies are also of key importance, as they can, for example, make a building or an industrial process more suitable for renewable heat options.

The **European Union** is the largest consumer of renewable heat worldwide, owing to the RED. Each member state has a mandatory target for renewables in total final consumption by 2020. While growth has generally been fastest in renewable electricity, many countries have also made considerable progress in renewable heat production. The overall share of renewable heating and cooling increased from 13.3% in 2008 to 19.1% in 2016,[4] with Sweden having the highest share (68.6%) and the Netherlands the lowest (5.5%).

After 2020, the RED will change considerably because a new target of 32% overall renewables consumption by 2030 was agreed to in June 2018. Although this is a binding target for the European Union as a whole, there are no binding targets for individual member states. For the first time, a specific target for renewable heating and cooling has been included in the RED, as it suggests that member states increase renewables used in heating and cooling by 1.3 percentage points annually to 2030. However, this target is non-binding and it is too early to know how it will drive deployment.

A number of member states have made changes to their renewable heat policies. The **Netherlands** has recently adopted new plans to diminish the role of gas in buildings. The government aims for 30 000 to 50 000 homes (out of 8 million households) to be natural gas-free or ready for alternative

[4] http://ec.europa.eu/eurostat/web/energy/data/shares. The EU definition of renewable heat differs from that employed in this report to include renewable energy from heat pumps, which is not currently captured in IEA statistics. The EU methodology of accounting for heat produced by heat pumps is not mirrored elsewhere, so no comparable global data that include heat pumps are available.

fuels by 2030. As a first step, it amended the Gas Act, removing the right to a gas connection in new homes. Regional authorities, together with municipalities, provinces, water boards and network managers are expected to draw up sustainability plans for the built environment.

In France, the budget of the *fonds chaleur* (The Heat Fund) support scheme was increased from EUR 200 million (USD 248 million) to EUR 245 million (USD 276 million) for 2018. In addition, a new strategy for solar energy was published by the government in June 2018, which includes new measures for solar thermal, as well as a commitment to introduce a renewable heat obligation in new buildings from 2020. The **United Kingdom** has made further changes to its Renewable Heat Incentive. Tariffs for biogas and biomethane were raised in May 2018 (reverting back to those in place in 2016), and at least 50% of feedstocks must come from waste residues. In **Spain**, the Ministry of Economy is funding a newly created Technology Platform on Low-Temperature Solar Thermal to stimulate the innovation potential of this technology.

In **India**, the National Biogas and Manure Management Programme (NBMMP) has set a target for 65 180 biogas plants in 2017-18. At the same time, the Off-Grid and Decentralized Concentrated Solar Thermal (CST) Technologies for Community Cooking, Process Heat and Space Heating & Cooling Applications in Industrial, Institutional and Commercial Establishments programme was extended in February 2018 to run until 2020. It has a target of a 90 000-square-metre (m^2) collector area.

In **China**, a five-year (2017-21) clean heating plan for northern China was adopted in December 2017 to cut coal consumption by 150 million tonnes (Mt) over the period and favour renewables and other cleaner sources of heating. Within this plan, a programme to develop biomass-based heating has been launched, with 136 co-generation[5] plants to be constructed by the end of 2018. Furthermore, in July 2017 a three-year clean heating action plan covering Beijing, Tianjin, Shanghai and the key cities of Hebei, Henan, Shaanxi, Shanxi, Shandong, Jiangsu, Zhejiang and Anhui was announced.

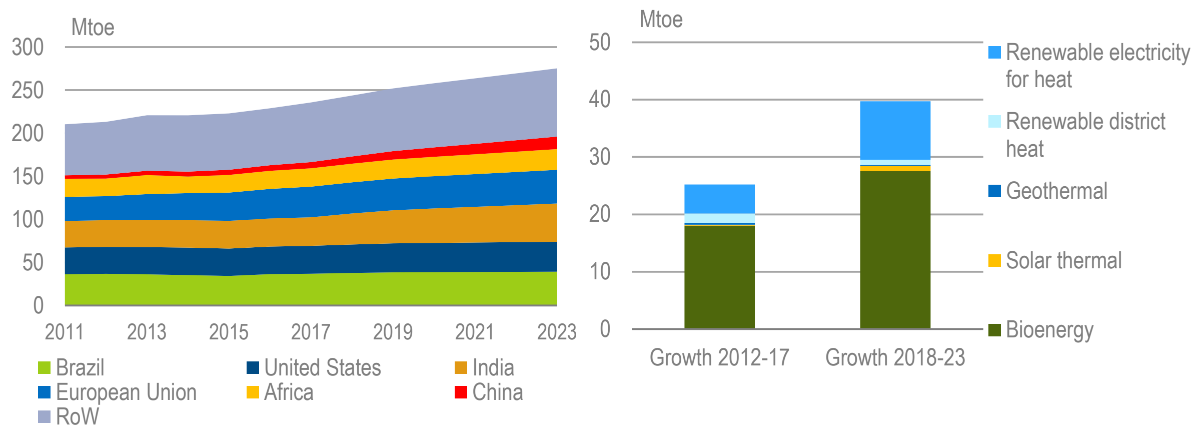
Elsewhere, the **United States** reinstated tax credits for ground-source heat pumps in February 2018, retroactive to January 2017. In addition, a new USD 15-million rebate programme applies to ground-source heat pumps installed in the state of New York. Conversely, the **South African** Department of Energy cut its solar water heater programme budget to zero for the 2018-19 tax year. While growth in installed solar thermal capacity in 2016-17 was 4%, this step is likely to retard future deployment.

Industry and agriculture

Industry accounted for 51% of total global heat consumption in 2017, with agriculture consuming another 3%. These two sectors also claim 52% of global renewable heat consumption. The majority (87%) of renewable heat used in industry is bioenergy, which is also expected to have the largest absolute growth over 2018-23; renewable electricity demonstrates the second-largest growth (Figure 4.3). This reflects greater industrial electricity use (up 20%, compared with 9% growth in overall industrial heat demand), as well as a larger share of renewables in global power generation. In addition, solar thermal consumption is expected to double, but from a very small base.

[5] The combined production of heat and power.

Figure 4.3 Industry renewable heat consumption by country/region (left) and growth in consumption by technology (right)



Sources: IEA (2018d), *World Energy Statistics and Balances 2017* (database), www.iea.org/statistics/; IEA (forthcoming), *World Energy Outlook 2018*.

In 2017, Brazil was the largest industrial consumer of renewable heat due to the extensive use of bagasse in the sugar and ethanol industry, and charcoal in iron and steel production. Over 2018-23, growth in industrial consumption of renewable heat is expected to be below the global average of 17% in Brazil, as well as in the European Union and the United States. Conversely, in India it increases 34%. But even this expansion is dwarfed by the anticipated doubling of consumption in China from 7.2 Mtoe to 14.5 Mtoe, with increases in renewable electricity for heat and bioenergy use.

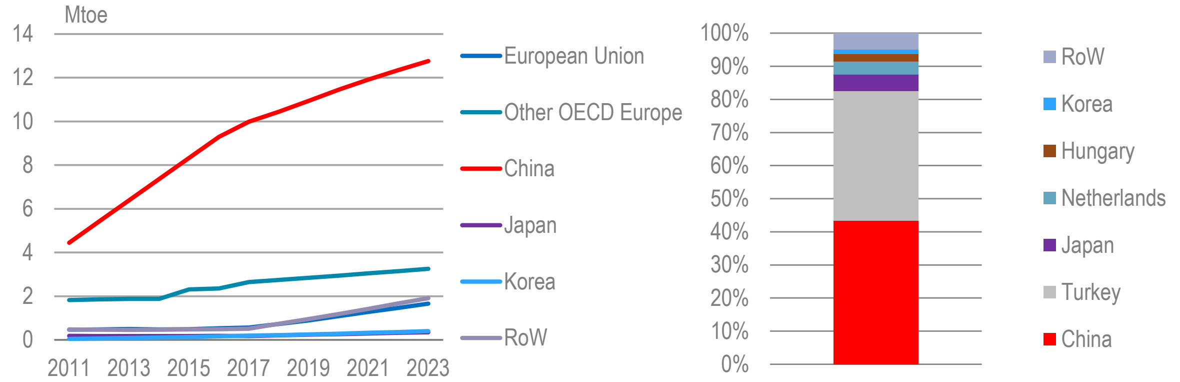
Agriculture is a small, but nonetheless important, user of renewable heat. In 2017, 8% of the heat consumed in the agriculture sector was renewables-based, primarily from bioenergy. Much bioenergy used in the sector is sourced from agricultural residues and high-moisture-content organic wastes suitable for biogas production. Geothermal energy is also used, especially for heating greenhouses. Agricultural renewable heat consumption is expected to rise 24% over 2018-23, mostly from bioenergy, but solar thermal applications are also expected to expand. Geothermal-based growth remains limited to very few countries.

Geothermal

Only a limited number of countries use geothermal energy directly for heat production, with China and Turkey alone accounting for 80% of consumption in 2017. Iceland is unusual in that geothermal energy makes up most of its overall heat consumption, whereas elsewhere geothermal tends to be the smallest source of renewable heat. In 2012-17, China's consumption more than doubled (Figure 4.4), although in 2017 geothermal still accounted for less than 1% of its total heat demand. Geothermal heat consumption is expected to grow more slowly over the outlook period, but China continues to dominate the global increase by far.

While most geothermal heat is used for bathing (45%) and space heating (34%), agriculture (primarily for heating greenhouses) has long been an important end-use sector in some countries. For example, Turkey, which uses the second-largest amount of geothermal energy in agriculture after China, had 770 megawatts thermal (MW_{th}) of geothermal greenhouse heating in operation in 2016 (RVO, 2017).

Figure 4.4 Geothermal consumption growth, 2011-23 (left), and geothermal use in agriculture by country, 2016 (right)



Sources: IEA (2018d), *World Energy Statistics and Balances 2017* (database), www.iea.org/statistics/; IEA (forthcoming), *World Energy Outlook 2018*.

In recent years, growth in geothermal heat use has been particularly strong in the large, energy-intensive greenhouse industry in the Netherlands. In fact, the use of geothermal heat in Dutch agriculture increased eightfold between 2011 and 2016 (from 8 kilotonnes of oil equivalent [ktoe] to 68 ktoe) and the country has become the fourth-largest user of geothermal heat in the agriculture sector after China, Turkey and Japan.

A key reason for this growth has been support for geothermal heat under the Stimulation of Sustainable Energy Production (SDE+) renewables scheme, as well as the availability of a government-owned geological risk mitigation fund. Recent installations include the Agriport G7 greenhouse area for which two new wells with a capacity of 17 MW_{th} were commissioned in 2017, adding to the four wells (10 MW_{th}) already in operation since 2014. Another two wells (18 MW_{th}) are to become operational in the Grootslag greenhouse area later in 2018 and further developments are planned elsewhere.

Greece, where geothermal heat consumption in agriculture fell by half between 2009 and 2016, recently dedicated new investments to geothermal greenhouse heating. For example, in Chrysoupoli in northern Greece, a new 3.5-hectare (ha) geothermally heated greenhouse for propagating plants was opened in 2017, with further expansion to 6 ha planned. Another 5-ha complex of greenhouses based on geothermal heating is planned at Nea Kassini, as are mixed developments of district heating and greenhouse heating in Alexandroupolis (Arvanitis, 2017).

Elsewhere, new geothermal heat developments have focused mainly on district heating. In the European Union, nine plants were put into operation in 2017, with 75 MW_{th} of new capacity in France, Italy and the Netherlands. Total EU capacity amounted to 1.8 gigawatts thermal (GW_{th}) in 2017, two-thirds of which was in Germany, France and Hungary (EGEC, 2018). Nearly 200 additional projects are under development or investigation, so that total capacity is set to grow further over the outlook period, including in new markets such as Poland and Denmark.

Solar heating for industrial processes

2017 was a record year for solar heating in industrial processes (SHIP), with 124 projects in 17 countries adding over 130 MW_{th} (a 46% increase), led by the first 100-MW_{th} phase of the Miraah project for enhanced oil recovery (EOR) in Oman and followed by developments in India (11 MW_{th}), China

(8 MW_{th}), Mexico (4 MW_{th}) and Afghanistan (2 MW_{th}). This brings cumulative capacity to almost 430 MW_{th} across 624 projects. Nonetheless, SHIP remains only a fragment of the global solar thermal market, accounting for 0.4% of additions in 2017 and 0.1% of cumulative thermal capacity (IEA-SHC, 2018).

Untapped potential is vast, especially in regions in which low-temperature heat demand is growing for industrial uses such as foods and beverages, textiles and agriculture, and chemicals. Greater solar thermal heat use for industrial processes will depend on policy support, greater public awareness, supply chain development and cost reductions.

SHIP is expected to more than triple from 0.4 Mtoe in 2017 to 1.3 Mtoe in 2023, or 3% of the solar thermal share of total final energy consumption. Growth is projected to come from India (26%), the United States (16%), Korea (12%), the European Union (11%) and China (7%). Planned EOR projects in Oman and California contribute an additional 0.3 Mtoe for heavy oil extraction.[6]

In countries with high direct irradiation, business models that could boost SHIP would offer energy service companies (ESCOs) very economical payback periods that match industry expectations and, in some cases, are shorter than for fossil fuel alternatives. Lack of awareness and acceptance are the primary barriers to the sector's growth, however. Government targets – such as China's ambitious goal to have 10% of industrial heat demand supplied by solar thermal by 2020 and India's to have 63 MW_{th} of concentrating solar thermal capacity for industrial processes (also by 2020) – may provide the nascent industry with the certainty needed to increase investment.

Focus on bioenergy in industry

Bioenergy is well suited to provide the temperature, pressure and quantity of thermal energy (either in the form of direct heat or steam) required by many industries. In addition, it is dispatchable so can meet the high availability requirements of many industrial processes. Replacing fossil fuels with biomass and waste is therefore one way to decarbonise the industry sector's high energy demand (2 855 Mtoe in 2017[7]). In 2017, bioenergy met 7% of industry energy demand (204 Mtoe), but this share is anticipated to remain stable until 2023 as bioenergy consumption growth of 13% (231 Mtoe) is accompanied by industrial heat demand growth of 11%.

The potential to use bioenergy varies by sector. The pulp and paper industry already exploits biomass resources extensively for energy production, while the potential to increase biomass use in sugar and ethanol production and in the cement industry is considerable. In other sectors that do not produce biomass wastes and residues on-site, however, scaling up bioenergy use is more challenging.

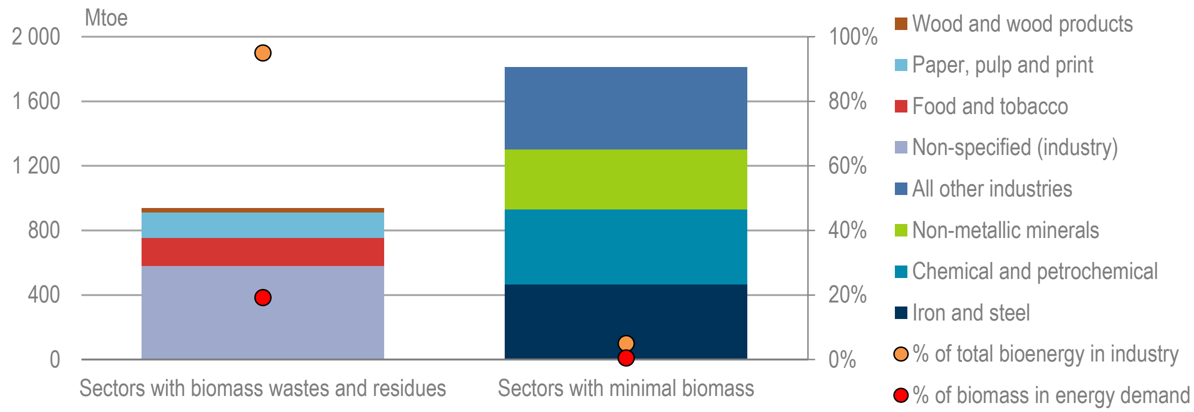
Cross-sectoral overview

The amount of energy demand covered by bioenergy varies significantly by industry subsector, from negligible amounts in iron and steel to almost 30% in pulp and paper. A key determinant for the use of bioenergy in industry is whether biomass wastes and residues are produced on-site through normal operations and can be used as fuel. The industry subsectors that produce the most biomass waste and residues account for only one-third of industry energy demand but almost all industrial bioenergy use. In those sectors, bioenergy accounted for 19% of final energy consumption in 2016 (Figure 4.5).

[6] From the perspective of energy statistics, solar thermal for EOR is a transformation process and is therefore treated separately from other industrial end uses in this forecast.

[7] Including energy demand from blast furnaces and coke ovens.

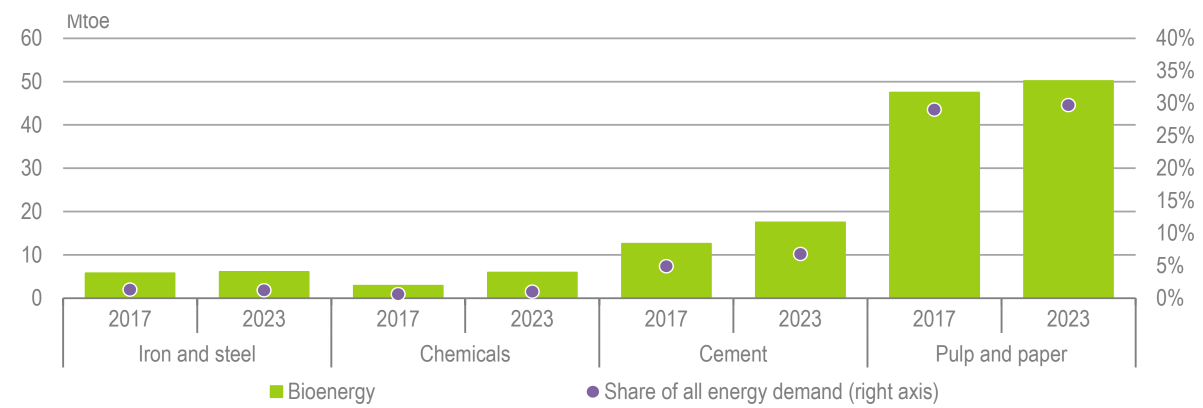
Figure 4.5 Share of bioenergy in energy demand by industry subsector, 2016



Source: IEA (2018d), *World Energy Statistics and Balances 2017* (database), www.iea.org/statistics/.

In those industries that produce minimal or no biomass residues and wastes on-site, bioenergy is scarcely used. The three most energy-intensive industry subsectors (chemicals, cement, and iron and steel) fall within this group, so energy demand from industries using minimal bioenergy is double that of industries that do employ it.

Figure 4.6 Bioenergy and waste use in selected industries in 2017 and 2023



Sources: IEA (2018d), *World Energy Statistics and Balances 2017* (database), www.iea.org/statistics/; IEA (forthcoming), *World Energy Outlook 2018*.

Little bioenergy is used in these energy-intensive subsectors because biomass fuel supply chains need to be established (Figure 4.6). This would require that suitable biomass resources be available as well as a viable means of transporting them. In addition, biomass fuels need to be cost-competitive with the fossil fuels they are replacing, especially since policy support for renewable energy use in industry is limited in many countries. Also important to consider are fuel calorific value and the compatibility of biomass fuels with existing equipment and process needs. These factors may also limit bioenergy uptake in certain industries.

Pulp and paper

Pulp and paper is the fourth-largest industry in terms of energy consumption, but the only energy-intensive subsector in which bioenergy meets a considerable amount of total energy demand. In 2017, bioenergy provided almost 30% (47.5 Mtoe) of the energy consumed in the pulp and paper industry globally, making it the subsector that uses the most bioenergy. Over the outlook period, however, the portion of energy demand met by bioenergy remains stable, as consumption is expected to grow only 6% (50 Mtoe) by 2023.

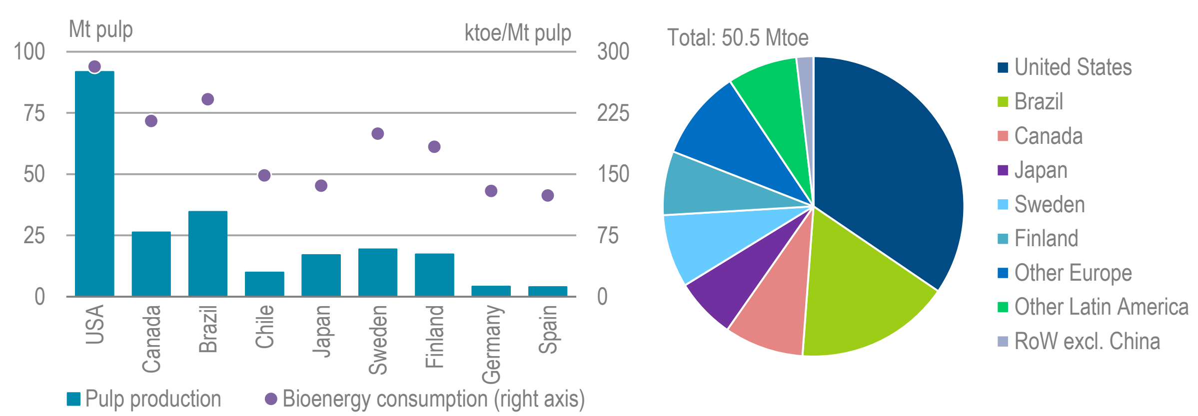
The pulp and paper industry produces a range of products, including wood pulp,[8] consumer paper, newsprint, tissue and cardboard. Biomass wastes and residues are produced at various stages of pulp and paper production. The pulping process produces most of the wastes and residues used for energy generation, the most important of which is black liquor generated during chemical pulp manufacturing. It contains dissolved lignin and hemicellulose from wood that is not required for paper production, as well as dissolved inorganic pulping chemicals. Other biomass fuels produced on-site include bark and wood residues and sawdust, and sludge with high biomass content.

Because the amount of energy consumed for pulp and paper production is significant, there is a strong incentive to maximise the use of the biomass resources produced on-site as fuels, as they have zero cost and can subsequently limit the cost of process energy. After pulping chemicals are recovered, black liquor is commonly used to produce process steam and electricity in a recovery boiler with a back-pressure turbine. A secondary boiler to combust bark and effluent treatment sludge is also often used.

The amount of bioenergy consumed relative to pulp output varies significantly by country (Figure 4.7) due to:

- Pulping technology: Chemical pulping produces more biomass residues than mechanical pulping, and bioenergy potential is therefore higher.
- Type of fibre: The use of recovered as opposed to virgin fibres results in lower biomass waste and residue production, and therefore less bioenergy.

Figure 4.7 Pulp (left) and black liquor production (right), 2016



Notes: RoW excl. China = rest of world excluding China. Black liquor data for the United States are estimated.
Sources: FAO (2018b), *Forestry Production and Trade* (database); IEA (2018a), *Renewables Information* (database), www.iea.org/statistics; IEA (2018d), *World Energy Statistics and Balances 2017* (database), www.iea.org/statistics.

[8] Composed of cellulose fibres from wood, the main component of paper.

Limited bioenergy growth expected in the pulp and paper industry

Bioenergy consumption over the next five years is expected to be limited by low energy demand growth in the pulp and paper industry. Energy demand grows by just 3% over the outlook period, to 169 Mtoe. Higher demand for sanitary tissue and for packaging material for online commerce is expected to be offset by declining demand in the paper and print market due to greater digitalisation.

The use of recovered fibres also limits bioenergy consumption, as less processing of virgin biomass reduces the volume of biomass waste and residues that can be used for energy purposes. In addition, less thermal energy is needed to re-pulp recovered fibres than to extract virgin fibres from wood feedstocks. As a result, in countries in which recovered fibre pulp accounts for a relatively high proportion of all pulp production, such as France and Spain (where the share is over 50%), bioenergy consumption per unit of output is lower than in countries that process more virgin fibres.

Growth in bioenergy use is also limited by the fact that biomass wastes and residues are already utilised extensively in the pulp and paper industry, so there are relatively few straightforward opportunities to ramp it up. Because using co-generation to provide the heat and process steam required for pulping is standard industry practice, the scope to produce more heat by replacing electricity only with co-generation systems is limited. Substituting less-efficient co-generation plants for the best available co-generation technologies could, however, increase the efficiency of biomass use and allow modern pulp mills to sell excess heat and electricity.

Factors that could increase bioenergy use in the pulp and paper industry

Shifting to best available technologies, exploiting opportunities to sell excess electricity and heat, and low-level use of recovered fibres in some countries could lead to an increase in bioenergy consumption.

The relatively low efficiency of recovery boilers, generally around 65-70% (IETD, 2018), offers scope to improve the efficiency with which biomass resources are used. This can be achieved by transitioning to high-energy recovery boilers or gasifiers to increase thermal energy recovery from black liquor, and consequently maximise heat and electricity output from biomass resources.

Gasification can also deliver a higher electricity-to-heat ratio and potentially offer a means to produce other high-value products, e.g. transport fuels and chemicals. However, black liquor gasification technology is not yet at the commercialisation stage, mainly because the black liquor recovery boilers currently in use are essential to pulp mill operations, and interest in investing in new technologies that have not been widely commercially demonstrated is therefore limited. In Finland, two pulp mills gasify bark residues to produce energy: one of them, which was commissioned in 2017, reports having 240% electricity self-sufficiency (MetsäFibre, 2018).

Modern chemical pulp mills can generate surplus electricity and heat for export, so selling excess electricity after on-site demand is met may offer another revenue stream, depending on electricity prices and policy incentives. For a mill to sell excess heat, it must have suitable heat distribution infrastructure and an offtaker in the vicinity, as is the case in Nordic countries, where pulp mills often supply municipal district heating networks.

The dampening of bioenergy production by greater recovered-fibre use is likely to be mitigated in some countries. In the United States and Canada, despite relatively high paper recovery rates, recovered fibre accounts for a small share of all pulp produced because North American pulp mills generally prefer virgin fibres for their higher homogeneity and the greater economies of scale they offer. Furthermore, virgin fibres are more suitable for the packaging products important to North American markets. In Latin America, pulp and paper production is expanding but paper recovery rates are relatively low.

Sugar and ethanol

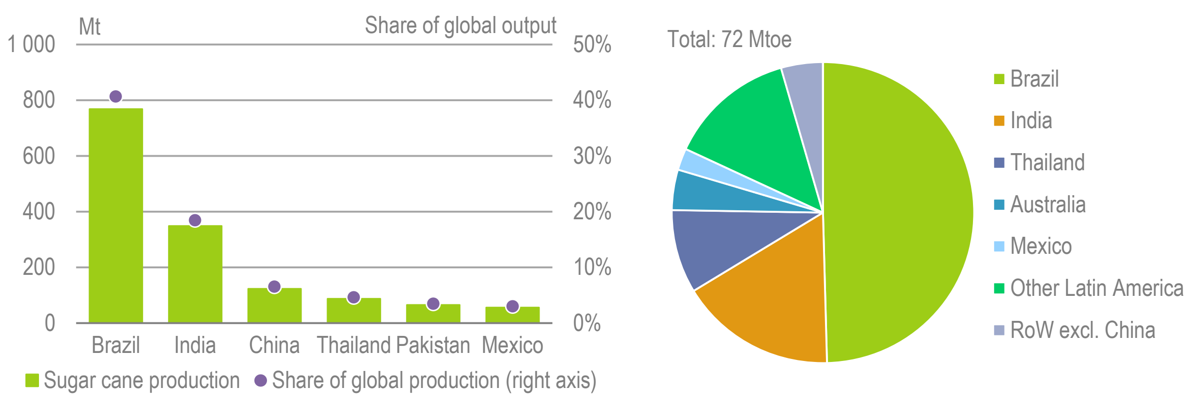
Sugar and ethanol production is considered part of the food and tobacco industry. Bioenergy covers a notable portion of the food and tobacco subsector's final energy consumption, meeting 18% of demand in 2016 because on-site biomass residue and waste production is aligned with low- and medium-temperature processes that can accommodate biomass fuels.[9]

In the sugar and ethanol industry, bioenergy meets an even greater portion of energy demand because sugar cane bagasse is used to generate process heat and electricity for on-site use and export. Although biomass residues are already utilised in co-generation plants, transitioning to higher-efficiency co-generation plants and using more sugar cane straw and new sugar cane varieties could generate significantly more bioenergy.

The energy potential of sugar cane is considerable, as almost all parts of the plant are suitable for energy purposes. Sugar cane juice can be used to produce sugar or ethanol; bagasse residues left after juice extraction can be used for co-generation or for producing advanced cellulosic ethanol; and sugar cane straw remaining in the field can also be used for co-generation.[10] Furthermore, the molasses by-product of sugar production can be used to produce fuel-grade ethanol.

Around 90% of global sugar cane production occurs in the tropical and subtropical areas of seventeen countries, all but four of which are in Latin America and Asia. Brazil is by far the largest sugar cane producer, accounting for 40% of production in 2016 (Figure 4.8). Sugar cane is also the most abundant renewable primary energy source in Brazil, providing 17.4% of the country's energy supply in 2017 (EPE, 2018). India and China are the second- and third-leading sugar cane producers, and their production, along with that of Brazil, amounted to two-thirds of the global total in 2016.

Figure 4.8 Production of sugar cane (left) and bagasse (right) in selected countries, 2016



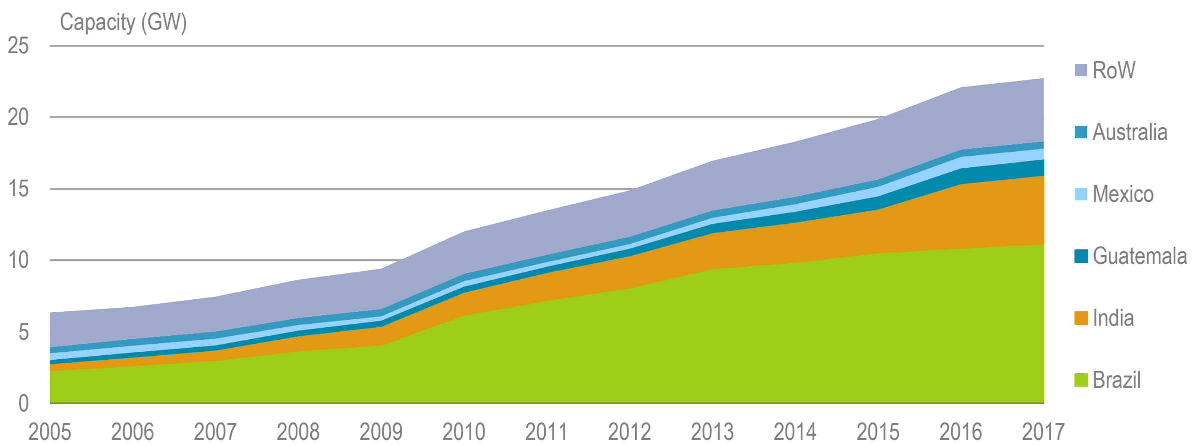
Note: No data available for RoW excl. China.
Sources: IEA (2018a), Renewables Information (database), www.iea.org/statistics; FAO (2018a), FAOSTAT Crops (database), www.fao.org/faostat/en/#data/QC.

[9] Low-temperature processes generally require temperatures below 100 degrees Celsius (°C), and medium-temperature ones use 100°C to 400°C.

[10] Ethanol can be used for vehicle fuel ('fuel ethanol'), beverage production and other industrial uses; most mils produce both sugar and ethanol. Bagasse is the residue left after sugar cane is crushed. Sugar cane straw, composed of leaves and tops, is commonly termed 'trash'.

The combustion of bagasse in co-generation plants is standard industry practice, as steam is required at mills for evaporation processes, sugar cane juice treatment and sugar-drying. In 2017, the electrical capacity of bagasse co-generation reached 23 gigawatts (GW) (IRENA, 2018), or 19% of global bioenergy capacity (Figure 4.9). Bagasse combustion is a low-cost form of biomass electricity generation: in Brazil, for example, government auctions have awarded power purchase agreements (PPAs) to bagasse electricity projects at prices of around USD 60 per megawatt hour (/MWh).

Figure 4.9 Bagasse-fuelled electricity capacity, 2005-17



Source: IRENA (2018), *Renewable Capacity Statistics 2018* (database), www.irena.org/publications/2018/Mar/Renewable-Capacity-Statistics-2018.

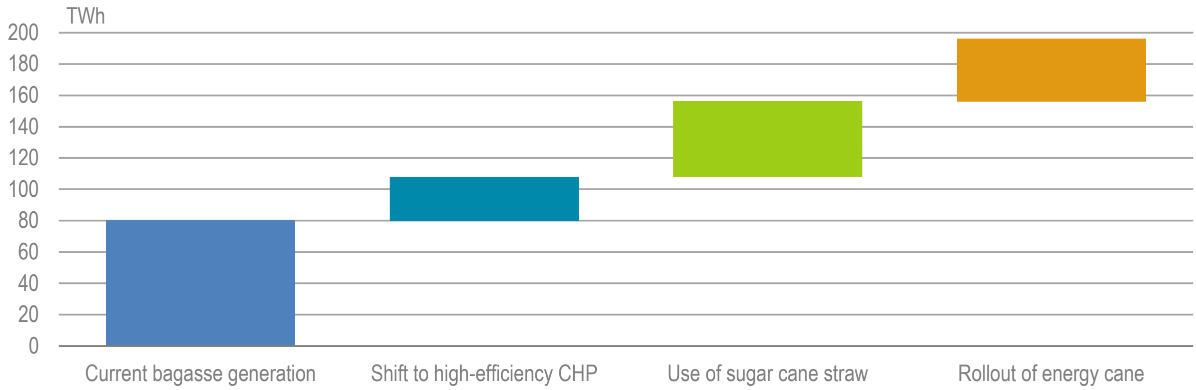
Significant untapped potential to scale up sugar and ethanol industry bioenergy generation

Transitioning to higher-efficiency co-generation plants and using more sugar cane straw could generate considerably more surplus bioenergy per tonne of sugar cane. Furthermore, using new sugar cane varieties (i.e. 'energy cane') could maximise the volume of bagasse resources available from the same planted area.

Many sugar mill co-generation systems operate at relatively low efficiency because the low-pressure backpressure steam turbines commonly used are designed to produce steam at the pressure required for on-site processes. The level of electricity generation in these systems is not optimised, however, and consequently the full energy potential of bagasse resources is not exploited. Transitioning to higher-pressure co-generation systems is therefore a key way to increase surplus energy production. Replacing backpressure steam turbines with condensing extraction steam cycle turbines (CEST) maximises surplus electricity and provides an additional revenue stream for mills.

In fact, if all sugar cane-cultivating countries were to exploit the potential of high-efficiency co-generation, sugar cane straw and new energy cane varieties, an additional 190 terawatt hours (TWh) of biomass electricity could be generated. This would more than double existing bagasse electricity generation, making it equal to one-third of global biomass electricity generated in 2017 and creating a considerable surplus for export (Figure 4.10).

Figure 4.10 Global electricity production potential in the sugar and ethanol industry



Notes: Bagasse generation data are not collected by the IEA and are therefore estimated. Scale-up potential for electricity is based on extending high-efficiency co-generation to 60% of bagasse resources, collecting 30% of available sugar cane straw and subsequently using it in high-efficiency co-generation, and increasing bagasse availability 20% through the rollout of energy cane varieties.

Such an increase in co-generation efficiency and fuel availability could also produce an additional 500 TWh of heat, although exploiting it would be challenging since local demand and suitable heat distribution infrastructure are necessary. Even if all additional electricity and heat output were fully utilised, this would represent only 55% of the overall energy potential of sugar cane bagasse and straw, which exceeds 100 Mtoe. Consequently, considerable potential to use sugar cane residues to produce cellulosic ethanol is also anticipated.

Although Brazil, India, Pakistan and Thailand have introduced measures to raise bagasse co-generation efficiency in their sugar and ethanol industries, opportunities remain for more widespread bagasse co-generation plant upgrades in these and other sugar cane-cultivating countries. For example, 43 of Mexico's 51 sugar mills offer scope to move to higher-efficiency co-generation (NAMA Facility, 2017).

Sugar cane straw is often left in the field because it adds nutrient value to the soil and its collection and use are not usually considered economically worthwhile. Sugar cane straw can, however, be used as a supplementary fuel with bagasse, although chlorine and alkalis in the straw may cause ash slagging and corrode boiler parts. Nevertheless, opportunities to export surplus electricity do provide a financial incentive for greater and more efficient straw collection, which can in turn improve air quality by reducing the in-field straw burning that is still commonplace in many countries.

Energy cane's sugar content is comparable with that of regular sugar cane varieties, but it maximises biomass yield for energy purposes. Energy cane trials suggest overall yields up to three times higher than for conventional cane varieties (IEA, 2017).

Several measures can be implemented to scale up bioenergy production in the sugar and ethanol industry:

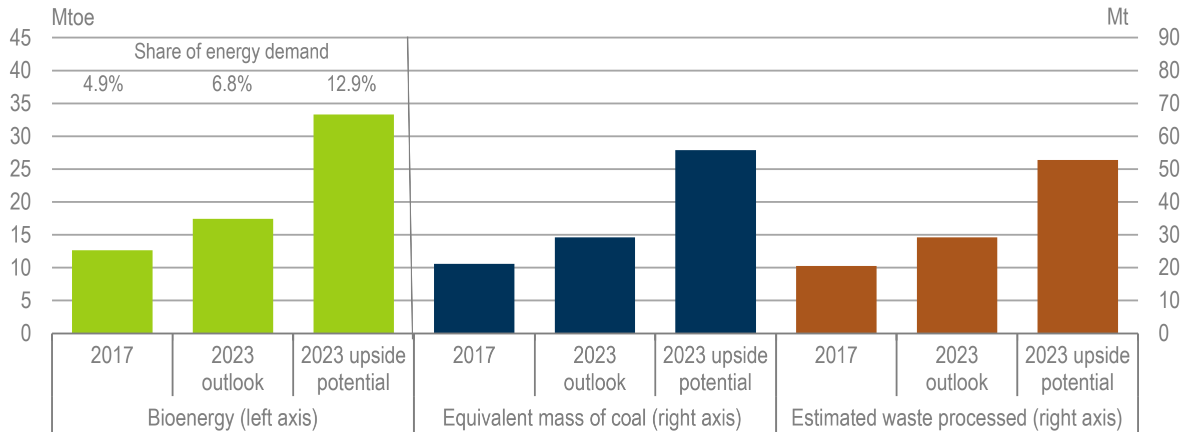
- Knowledge transfer and sharing of best practices among sugar cane-cultivating countries.
- Mechanisms to provide affordable financing to sugar mills, to facilitate investment in higher-efficiency co-generation plants and grid connections.
- Steps to remove grid access barriers for sugar and ethanol mills.

- Higher levels of mechanised harvesting to facilitate straw recovery.
- Ongoing research on energy cane varieties, and further trials of species in different climates.

Cement

The cement subsector is the third-largest industrial energy consumer, responsible for 9% (256 Mtoe) of global industry sector energy use in 2017, but bioenergy and waste supplied only 5% (12.6 Mtoe) of this demand (Figure 4.11). Bioenergy use is anticipated to grow nearly 40% by 2023, however, to 17.5 Mtoe, equating to almost 7% of cement industry energy demand.

Figure 4.11 Bioenergy and waste consumption in the cement sector and associated benefits



Notes: The accelerated outlook assumes that growth in biomass and waste fuel use from plants participating in the World Business Council for Sustainable Development's Cement Sustainability Initiative continues and is applied to all cement production globally. The equivalent mass of coal calculation assumes that all bioenergy replaces coal with no increase in thermal energy use from the consumption of alternative fuels; in reality, a range of fossil fuels may be replaced. Figures for mass of coal and for waste processed do not consider the different combustion characteristics of alternative fuels compared with fossil fuels.

Sources: IEA (forthcoming), *World Energy Outlook 2018*; WBCSD (2018), *Global Cement Database on CO_2 and Energy Information* (database), www.wbcsdcement.org.

Bioenergy could cover a significantly larger portion of cement subsector energy demand – potentially 33 Mtoe, or 13% by 2023. This would cut CO_2 emissions, as enlarging the share of bioenergy would displace fossil fuels, particularly coal, the principal fuel used to generate thermal energy for cement production.

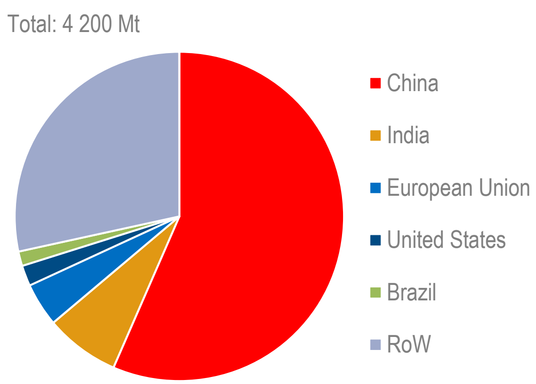
Two-thirds of bioenergy used in the cement industry is currently sourced from waste fuels. Using waste to fuel properly designed and operated cement kilns is a good alternative to landfill disposal or incineration. Cement plants can therefore provide valuable waste disposal services, especially in countries with limited waste management infrastructure. Consequently, enlarging bioenergy use in the cement subsector depends on applying more widespread and stringent waste management regulations similar to those that have proven successful in Europe for this purpose.

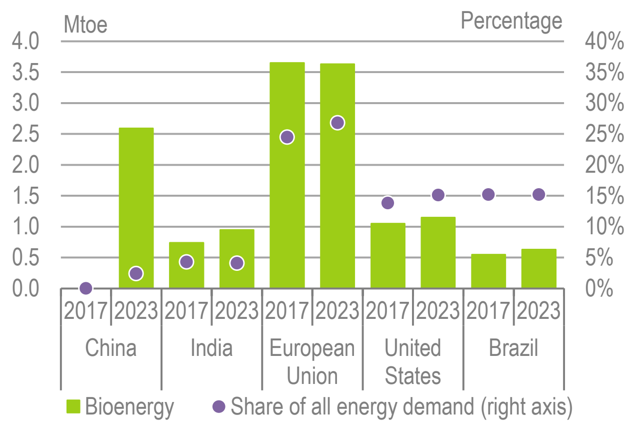
Biomass and waste as alternatives to fossil fuels for cement production

The thermal energy required to produce clinker, which is used as a binder in cement products, accounts for most of the total energy used in cement production. This thermal energy is typically produced from fossil fuels, mainly coal, which is the source of 70% of the thermal energy consumed in the cement industry globally. However, lower-carbon biomass and waste ('alternative fuels') can substitute for fossil fuels in cement kilns to generate the thermal energy needed for cement production, one of a suite of options to decarbonise the cement industry.

Renewable and non-renewable waste accounts for two-thirds of alternative fuel used in the cement industry, the remainder being biomass. Various renewable fuels are currently in use, such as woody biomass, agricultural residues (e.g. rice husks and sugar cane straw), industrial waste, animal waste and sewage sludge. Municipal solid waste (MSW) can also be used after processing to produce refuse-derived fuel (RDF).

Figure 4.12 Global cement production, 2017 (left), and bioenergy consumption (right)





The physical and chemical properties of many biomass and waste fuels differ markedly from those of fossil fuels.[11] Consequently, preprocessing is often required to ensure the suitability of their energy content and composition prior to use. The calorific value of the fuel determines whether it can be used in the main burner, precalciner or pre-combustion chamber; the lower process temperature of precalciner kilns particularly facilitates the integration of high shares of alternative fuels with lower energy content.

How much biomass and waste fuel is used in the cement subsector varies significantly by country (Figure 4.12). The European Union leads, with almost 25% of all energy demand sourced from bioenergy and waste in 2017, and some individual countries employ much higher shares, notably Germany and the United Kingdom. However, the European Union is responsible for only 4% of global cement production.

Key factors in the extensive use of RDF in the European cement industry are the high rates of waste collection and processing, as well as landfill taxation and gate fees that increase the cost of landfill

[11] The properties in question include calorific value, moisture content and the presence of undesirable contaminants such as chlorine and sulphur. Typically, greater shares of alternative fuels in a kiln lead to an increase in its thermal energy intensity, as the calorific value tends to be lowered. However, the net effect in CO_2 emissions reduction outweighs that of additional energy demand.

disposal. In addition, some countries have banned landfilling of certain types of waste, a measure that increases the use of thermal treatment methods such as co-processing in the cement industry.

India is the second-largest cement producer globally, with output on an upward trend. The contribution of bioenergy and waste to energy demand remains low at around 4% in 2017, but the potential for greater use of alternative fuels, particularly MSW, is strong. India's Nationally Appropriate Mitigation Action (NAMA)[12] for waste involves using RDF from urban areas within a specified distance from cement plants, and it anticipates that alternative fuels could generate almost 19% of the cement industry's thermal energy demand by 2030. India's waste management rules also promote the use of waste in industry when it is available within a 100-kilometre (km) radius.

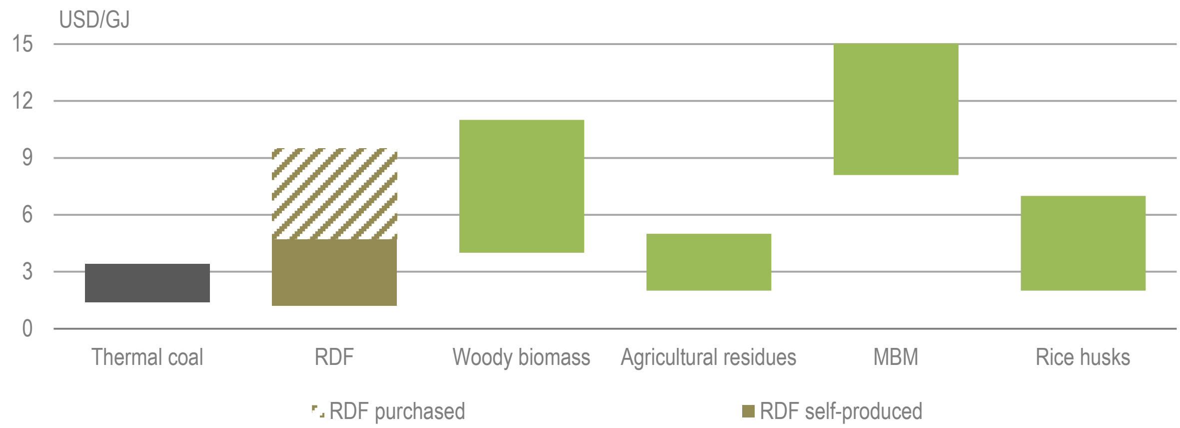
In Brazil, the use of alternative fuels in cement production is well established. Bioenergy and waste supplied 15% of the cement subsector's energy demand in 2017, and its use has increased markedly, with roughly 40 cement plants licensed to undertake co-processing. China accounts for over half of global cement production, but alternative fuel use is negligible, as coal meets almost all thermal energy demand. This could change over the outlook period, however, owing to pressing waste management and air quality drivers to offset coal with bioenergy, particularly MSW-derived fuels.

The economics of bioenergy within the cement sector

A cement plant operator's main objective in using alternative fuels is to reduce overhead energy costs for clinker production. Therefore, biomass and waste energy sources must be cost-competitive with the fossil fuels already being used.

The quality requirements of thermal coal used in the cement industry are lower than for coal used for electricity generation, and the cost is therefore generally lower. Consequently, it is challenging for higher-quality biomass fuels, such as wood chips or wood pellets, to compete on a fuel-cost basis (Figure 4.13). Fuels such as RDF, animal wastes and some agricultural residues can compete with coal, but they can be more challenging to use than forestry biomass and in most cases require preprocessing to ensure their combustion characteristics are suitable.

Figure 4.13 Estimated costs of coal, waste and biomass fuels used in clinker production



Notes: MBM = meat and bone meal. MBM costs can also exceed USD 15 per gigajoule (/GJ).

[12] NAMAs are country-driven initiatives that developing nations are implementing to achieve sustainable development while contributing to global efforts to reduce greenhouse gas emissions.

The economic case for self-produced RDF at cement plants is significantly stronger when landfill taxation and gate fees raise the cost of waste disposal, as is the case in many European countries. In such cases, cement kilns can act as a waste disposal service, which can create additional revenue, the value of which is determined by the cost of landfill disposal.

The flexibility of cement kilns to combust a wide range of fuels without major equipment refurbishment supports the economic case for bioenergy, but in order to produce RDF, existing cement plants need to invest in modifications enabling them to receive, handle, process and store wastes. In some cases, changes to burners and emissions abatement systems are also required.[13]

However, the investment costs associated with retrofitting equipment to process and combust RDF is low compared with the cost of a dedicated waste-to-energy plant, while new cement plants can be specifically designed to accommodate the use of alternative fuels.

Increasing bioenergy use in the cement industry

Demand for cement, a key constituent of concrete, is driven by infrastructure development and is therefore linked to wider trends in urbanisation and economic and population growth. Although production and energy demand in the cement subsector are expected to remain stable over the outlook period, more widespread application of the conditions that enabled the European Union to achieve high levels of bioenergy utilisation could help biomass and waste fuels offset a higher proportion of coal for clinker production worldwide.

Enlarging the share of alternative fuels in cement production requires primarily that an enabling framework be established, rather than further technological development. Once enabling conditions are in place, the relatively small number of international companies that account for a significant share of global cement output could rapidly scale up alternative fuel use.

Waste-based fuels hold the largest potential to raise bioenergy consumption in the cement industry, and the key means of making more RDF available is comprehensive waste management policies to control the collection, sorting and pre-treatment of MSW. In addition, policies that put a price on waste disposal improve the economic viability of RDF production and use by cement plants. Further enablers include the dissemination of technical competence in kiln operation with alternative fuels, streamlined permitting for the use of wastes, and stakeholder engagement with local communities.

Other energy-intensive sectors

Iron and steel is currently the second-largest industry subsector in terms of energy consumption, at 461 Mtoe of demand in 2017. Bioenergy use in the sector is negligible, around 6 Mtoe, and is anticipated to account for only 1% of energy demand throughout the outlook period.

Brazil is responsible for almost all solid biomass used globally in iron and steel production, as biomass is transformed into charcoal for the blast furnace reduction process that produces pig iron. Bioenergy met 42% of Brazilian iron and steel energy demand in 2017 (5.4 Mtoe), and consumption is anticipated to remain broadly stable in terms of energy over 2018-23. The source of biomass used for charcoal production has been subject to scrutiny, however, resulting in initiatives to replace unsustainable biomass from native forests with that from sustainably managed forestry plantations.

[13] Air pollutant emissions from well-managed cement plants using alternative fuels can be managed. However, to avoid negative human health impacts, best available technology for air pollution prevention and control with continuous emissions monitoring should be employed.

Charcoal use in iron and steel production is not expected to notably increase in other countries during the outlook period because: 1) blast furnaces specially designed to use charcoal have a lower capacity than those that combust coke; 2) the scale of forestry plantations required to supply enough biomass feedstock for charcoal production is considerable; and 3) charcoal must be cost-competitive with coke for greater uptake to occur (FAO, 2018c).

The chemical and petrochemicals industry is the largest subsector in terms of energy consumption (529 Mtoe in 2017). Bioenergy meets less than 1% of energy demand, and, although its use is projected to increase 3 Mtoe over 2018-23, this results from underlying energy demand growth in the sector (14% over the outlook period). The bioenergy share remains minimal in 2023. Biogas and the co-processing of liquid biofuels are potential bioenergy applications in the chemicals sector. Bioenergy use in aluminium production is negligible.

Opportunities for liquid and gaseous biomass fuel applications in industry

Although almost all bioenergy used in the industry sector is from solid biomass fuels, there are niche opportunities for both biogas and liquid biofuel applications in some industry subsectors.

The food and drink as well as the chemical and petrochemicals industries, in which natural gas is the principal fossil fuel used, hold key opportunities for biogas exploitation. When biogas is generated from feedstocks produced as part of operations in these subsectors, it can subsequently be used to generate heat and electricity to offset on-site energy demand. The best prospects for biogas market growth are in Europe, where deployment is most prevalent.

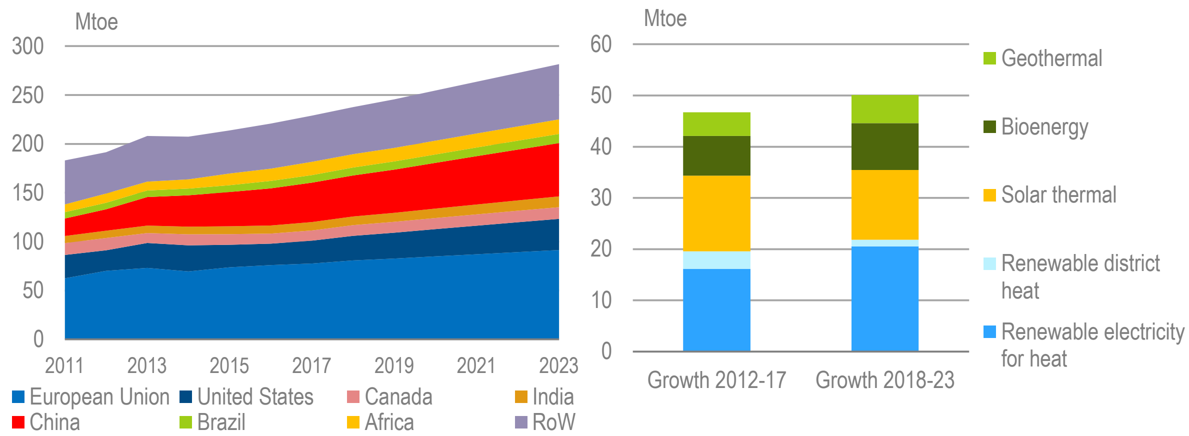
Wet wastes with high organic content from the food and drink industry are ideal anaerobic digestion (AD) feedstocks that hold energy production potential. On average in the European Union, however, these wastes constitute only a relatively minor portion of the feedstocks used for biogas, estimated at less than 5% in 2016 (EBA, 2017). Opportunities exist in the chemical and petrochemicals industry to use AD as a means of treatment for wastewater sludge with high levels of organic pollutants. France leads biogas use in this subsector.

Construction and the mining and quarrying industry offer opportunities for biodiesel use, as liquid petroleum products are the principal fuels used in both these subsectors. In the construction industry, liquid biofuels are consumed in some European countries as well as in the United States; they are also used in mining and quarrying for mobile generators and excavating machinery in Europe, the Philippines and the United States. In 2018, Indonesia mandated biodiesel use in the mining sector and is considering extending the mandate to cement and steel production. Using biodiesel to fuel underground mining machinery can also improve air quality by reducing emissions of carbon monoxide, hydrocarbons and particulate matter (PM).

Buildings

Just under half of all renewable heat produced globally is consumed in the buildings sector, with consumption the highest in countries with high space heating demand (Figure 4.14). EU countries jointly remained the largest consumer in 2017, as improved energy efficiency in buildings has contributed to steadily rising share of renewable heat (22% in 2017). With considerable solar thermal capacity expansions in recent years, China has overtaken the United States as the second-largest single consumer of renewable heat in buildings. Together with Canada, these countries account for two-thirds of global renewable heat consumption in buildings.

Figure 4.14 Buildings renewable heat consumption by country/region (left) and growth in final consumption by technology (right)



Sources: IEA (2018d), *World Energy Statistics and Balances 2017* (database), www.iea.org/statistics/; IEA (forthcoming), *World Energy Outlook 2018*.

China's consumption is expected to grow more slowly over 2018-23 than in the previous six-year period, as solar thermal market expansion continues to be sluggish. In the United States, however, growth is projected to accelerate to 36%, and in India to 29%. In absolute terms, buildings sector renewable heat consumption increases the most in European Union (13.8 Mtoe) and China (14.2 Mtoe), with both together accounting for over half of global growth over the outlook period.

While most renewable heat growth in the buildings sector in 2012-17 was in solar thermal, renewable electricity for heat leads consumption growth in 2018-23 thanks to rising shares of renewables in electricity generation and increasing electrification of heat production. The use of electricity for space and water heating and for cooking is expected to grow almost four times faster than global heat demand.

Bioenergy currently makes up the largest portion (47%) of renewable heat in buildings, both in direct and district heating applications, but its share is projected to fall to 42% by 2023 as the use of other technologies expands more rapidly. Together, renewable electricity for heat and solar thermal energy account for 70% of global renewable heat consumption growth over 2018-23.

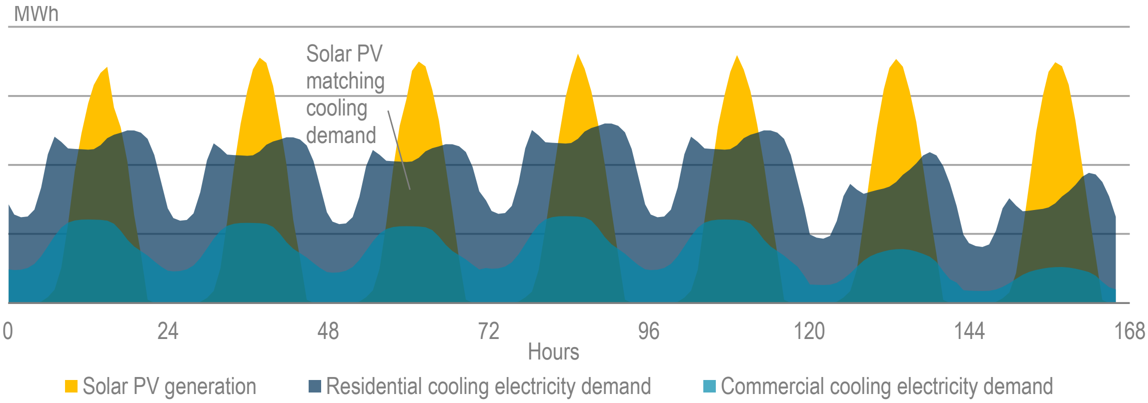
Cooling of buildings, while dwarfed by heating in terms of energy consumption, is a rapidly growing energy end use (Box 4.1). As cooling is primarily electricity-based, renewables already indirectly supply a portion of the energy used. Direct renewable cooling solutions also exist, but limited data availability makes it impossible to provide a market outlook.

Box 4.1 Renewables and cooling

Cooling currently accounts for around 6% of energy consumption in the buildings sector, compared with a heat end-use share of almost 80%. However, according a recent International Energy Agency (IEA) report on the future of cooling, cooling demand in the buildings sector has been growing faster than other end uses, more than tripling between 1990 and 2016 (IEA, 2018b). Space cooling – typically through electric fans or air conditioners – is already putting an enormous strain on electricity systems in many countries and is driving up emissions. The problem is not only growing demand in general, but additional peak demand, especially on very hot days.

Although the primary solution is improved energy efficiency of air conditioners and building envelopes, renewables can make cooling more sustainable. The currently growing share of renewables in electricity generation means that they already indirectly contribute 40 Mtoe of the energy consumed for cooling. Furthermore, direct renewable cooling technologies such as solar thermal collectors combined with adsorption chillers are already being deployed in larger-scale (>100-kilowatt [kW]) installations in commercial buildings or district cooling systems. While they are relatively niche technologies at present, the market is growing. At the end of 2015,[14] an estimated 1 350 solar thermal cooling systems had been installed worldwide – 70% of them in Europe, mainly Spain, Germany and Italy (IEA-SHC, 2018). Costs have fallen by more than half since 2007, although they have not dropped as quickly as for solar photovoltaic (PV) technology. In 2017, large-scale solar cooling installations included an 880-kilowatt thermal (kW_{th}) system for an IKEA store in Singapore and a 3.1 MW_{th} system for a military teaching hospital in Managua, Nicaragua.

Figure 4.15 Illustrative daily profile of space cooling load and solar PV output



Source: IEA (2018b), *The Future of Cooling*.

For small and medium-sized cooling systems, the combination of solar PV and air conditioners/reversible heat pumps offers great potential. Solar PV generation and cooling demand operate in a very complementary fashion (Figure 4.15). In urban areas where distributed PV use has been growing rapidly, cooling drives self-consumption. Some storage may be needed, however, to cover cooling energy needs when solar energy is unavailable, for example in the evening when residential air conditioning demand tends to be high. Thermal energy storage such as chilled water or ice storage can be very cost-effective, especially when deployed at district scale. Thermal storage can also be used during periods of excess electricity production from variable renewable sources to avoid curtailment.

Bioenergy

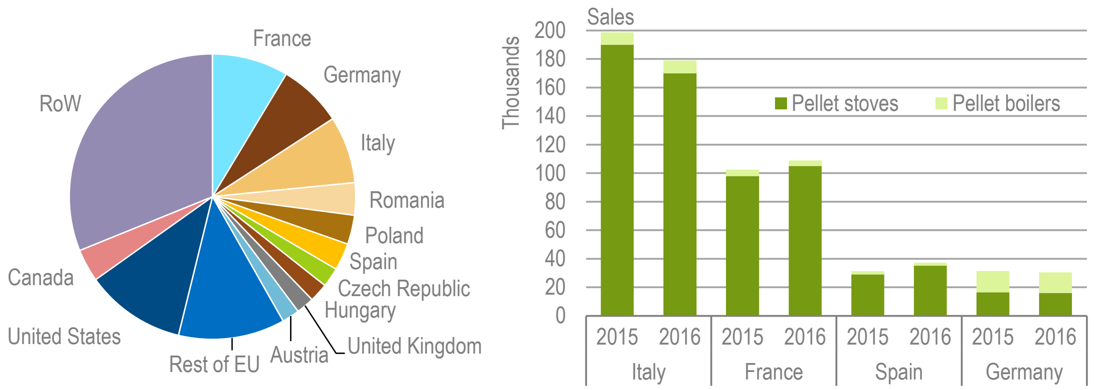
Bioenergy is widely used for heating, through a range of applications – from inefficient open fires used to heat just one room, to very efficient, modern pellet boilers that provide space heating and hot water in homes as well as commercial and public buildings. In addition, bioenergy is used in co-generation or in heat-only boilers for district heating to meet building and industrial heat demand. Sweden and Finland lead global consumption of bioenergy for district heating.

For individual bioenergy heating systems in buildings, the European Union is by far the largest consumer, accounting for 46% of global bioenergy consumption in buildings. Over 2018-23, further

[14] More recent figures not available as data collection is difficult.

growth of 8% is expected globally, although this is lower than the 16% growth of the past six-year period. In the residential sector, the European Union accounts for an even greater share of global bioenergy consumption (54%), with France, Germany and Italy consuming the most (44%) (Figure 4.16). Growth has been particularly rapid in pellet stoves in Italy: in 2016 (the most recent data available), Italy led the European market in pellet stove sales, although with a 10% year-on-year (y-o-y) decline, and pellet boiler sales rose slightly. In Germany, pellet boilers make up almost half of the market, although sales of both pellet boilers and stoves have declined 3%. France and Spain's pellet stove sales increased, while boiler sales fell.

Figure 4.16 Residential bioenergy consumption by country, 2016 (left), and pellet appliance sales in selected countries (right)



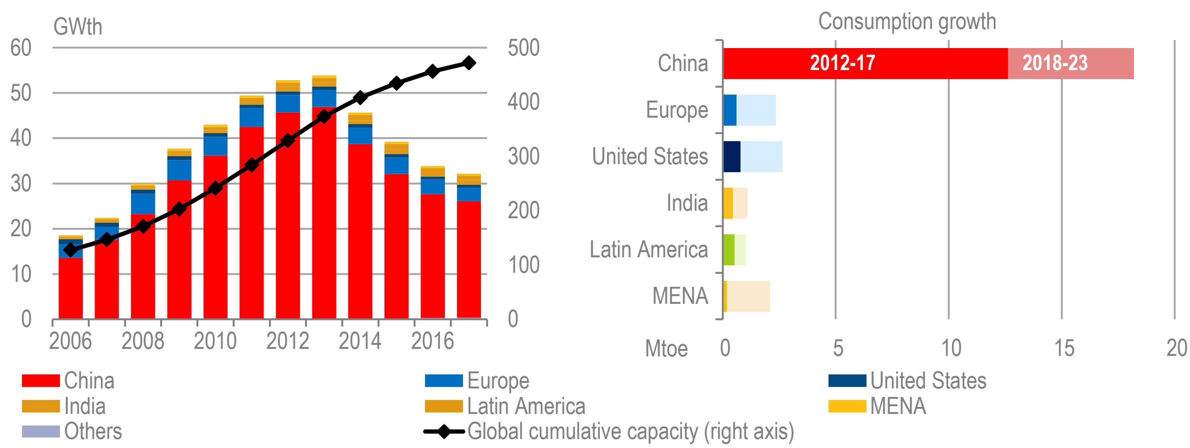
Sources: IEA (2018d), *World Energy Statistics and Balances 2017* (database), www.iea.org/statistics/ (left); Aebiom (2017), *Pellet Market Overview 2017* (right).

The United States has the largest single-country consumption of bioenergy in the buildings sector. However, significant annual fluctuations in consumption occur, linked to prevailing weather conditions and fuel cost dynamics. In recent years, bioenergy consumption was highest in 2014, when many states had cold winter conditions, and was lower in 2015-17 owing to milder winters. In 2017, however, wood pellet consumption for the domestic heating market increased 10% y-o-y, with an even higher increase in southern states. This was influenced by a drop in average wood pellet price from USD 160/tonne to USD 150/tonne over the year, coinciding with a y-o-y increase in residential heating oil prices. Over the outlook period, bioenergy consumption in buildings could increase 18% owing to various state-level incentives (IEA, 2018e), although the uptake of biomass heating will also depend on heating oil and natural gas prices.

Solar thermal

In 2017, solar thermal energy accounted for 14% of renewable energy consumption in buildings and capacity additions declined for the fourth year in row, by 4% to 33 GW_{th} (Figure 4.17). Continuous slowdown of the Chinese market, which represented 80% of growth in 2017, remains the key reason for declining gross capacity additions globally since 2013. Outside of China, additions were also lower in Europe and United States, while annual market growth expanded more quickly in India and the Middle East. Despite the global slowdown in additions, cumulative solar thermal capacity grew 3.5% y-o-y to reach 472 GW_{th} in 2017, one-fifth greater than total installed solar PV capacity. Solar thermal installations – mainly domestic hot water systems for single-family homes and large domestic hot water systems, followed by swimming pool heating – produced an estimated 33 Mtoe of energy in 2017.

Figure 4.17 Solar thermal gross capacity additions (left) and consumption growth in buildings (right)



Note: MENA = Middle East and Africa.

Sources: Based on IEA (2018d), *World Energy Statistics and Balances 2018* (database), www.iea.org/statistics/; IEA-SHC (2018), *Solar Heat Worldwide Edition 2018*; REN21 (2018), *Global Status Report 2018*.

Solar thermal consumption in buildings is anticipated to rise more than 40%, to 46 Mtoe by the end of the outlook period. This growth is almost 8% less than in the 2012-17 period due to slowdown in China and despite expected expansion in Europe, the United States, India and the Middle East. As a result, China's share in global solar thermal consumption is projected to fall from 72% in 2018 to 63% by 2023.

However, **China**'s consumption is still anticipated to grow by almost one-quarter over the outlook period, to account for 40% of global solar thermal capacity growth. Strong government targets for 2020 and efforts to reduce air pollution are important drivers for this expansion; nevertheless, the absence of economic incentives, a weaker housing market and increasing consumer preference for electric boilers impair uptake in the residential sector.

In North America, the **United States** leads growth, with its consumption projected to climb almost 70% over the outlook period. Residential sector installations are supported by a 30% federal investment tax credit (ITC), which is due to phase down to 10% in 2022. Solar pool heating applications, which are excluded from the ITC, remain an important growth market in the United States, as solar thermal technology continues to be cost-competitive with both gas and heat pump pool heaters in many parts of the country. In **Mexico**'s residential sector, cost-competitive residential applications also cause solar thermal energy consumption to almost double over the outlook period.

Europe's 9% of global solar thermal energy consumption is projected to rise by 78%: despite slower growth in annual installations, Germany, Italy and France lead consumption growth over the outlook period. Meanwhile, annual capacity additions in Turkey remain stable owing to low-cost thermosiphon systems, which results in higher residential sector consumption. Similarly, cost-effective domestic hot water heaters drive **India**'s solar thermal energy consumption, which is expected to almost double in the next six years to over 1.4 Mtoe. In the **Middle East**, buildings sector consumption increases six-fold over 2018-23, mostly in water desalination projects for which solar thermal technology offers cost-effective solutions.

While individual solar water heating installations dominate the global market, in several countries, led by Denmark, large-scale solar thermal plants connected to district heating systems or large buildings have been expanding. In 2017, 15 large-scale systems (30.4 MW_{th} of capacity) were added worldwide. By the end of 2017, roughly 300 large-scale (>350 kW_{th}) solar thermal systems were in operation, with a total capacity of 1 140 MW_{th}.

Heat pumps

Heat pumps[15] provide space heating, water heating or both; reversible heat pumps can provide heating and cooling. They are highly efficient, although their overall primary energy efficiency depends on the generation efficiency of the electricity (or other energy source) they use. Renewable energy (e.g. from ambient air, water or the ground) and "high-grade" energy, e.g. from electricity or gas, are used to raise the temperature for heating or to lower it for cooling (IEA, 2011). In the European Union, energy from heat pumps is credited as renewable, provided certain energy performance criteria are met.

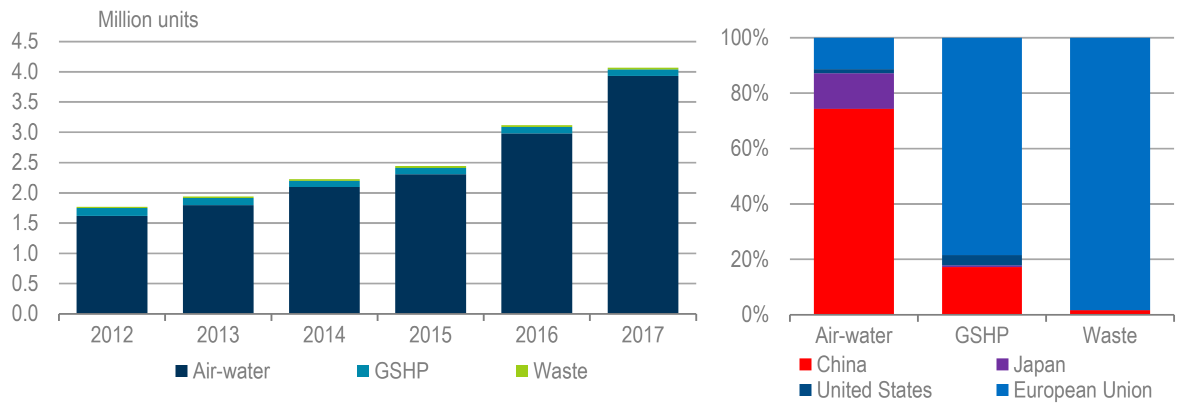
Heat pumps are likely to play a key role in the electrification of heat: they are among the most cost-effective options to increase the amount of space heating provided by low-carbon energy, and their efficiency is reinforced by growth in renewable electricity production. Furthermore, heat pumps could be used in demand-response systems to augment power system flexibility (IEA 2018c). In recent years, heat pump deployment has been strongly supported in numerous countries (e.g. China, Japan, the United States and EU countries) through national, sub-national and local-level policies, and through building code requirements for new constructions and refurbishments.

Globally, annual heat pump sales more than doubled from 1.8 million units in 2012 to over 4 million in 2017, with y-o-y growth of 30%; 93% of this growth was in China (Figure 4.18).[16] The market is dominated by air-water systems (97%), followed by ground-source heat pumps (3%), for which sales grew for the first time since 2012. Sales in China made up 72% of the total, followed by those in the European Union (14%), Japan (12%) and the United States (2%). A comparatively smaller market for exhaust air or waste-heat pump technology exists mainly in Europe, in domestic and industrial buildings (30 000 units) (BSRIA, 2018). Global data for reversible air-air pumps used for heating were not available, even though they account for most units sold in Europe. Therefore, while the exact size of the global market is currently unknown, it is larger than shown in Figure 4.18.

[15] This report includes air- and ground-source heat pumps. Air-air refers to pumps that use the air as a heat source and deliver heat via an air heat distribution system; air-to-water refers to heat distribution through a "wet" water-based heat distribution system.

[16] Global data are based on Building Services Research and Information Association (BSRIA) and cover Austria, Belgium, Finland, France, Germany, Ireland, Italy, the Netherlands, Norway, Spain, Sweden, Switzerland, Turkey, the United Kingdom, the Czech Republic, Poland, Slovenia, the United States, China and Japan. The data cover air-water, ground-source and waste-heat pumps, but not air-air heat pumps, which are covered for Europe only.

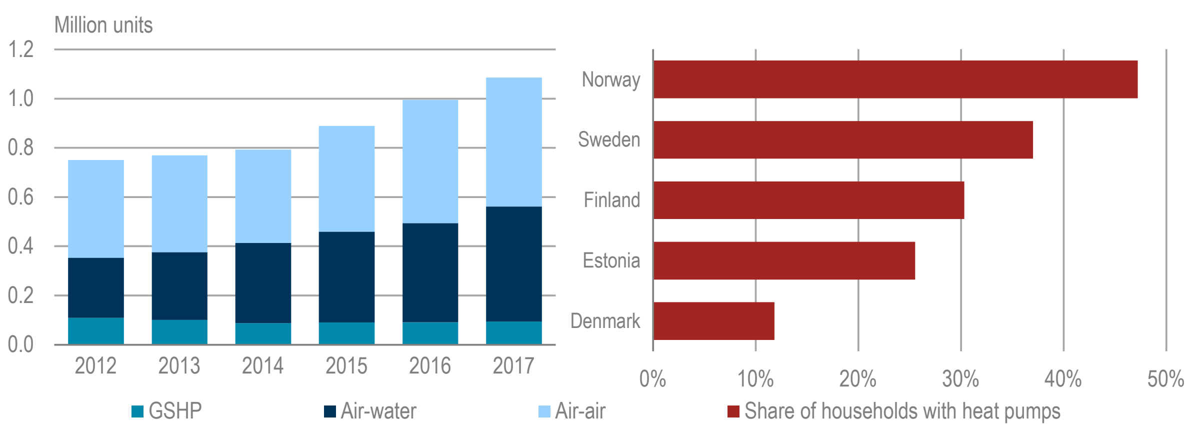
Figure 4.18 Global heat pump sales by technology, 2012-17 (left) and regional shares in 2017 (right)



Note: GSHP = ground-source heat pump.
Source: BSRIA (2018), *World Renewables: Heat Pump Market*.

In Europe, annual heat pump sales reached nearly 1.1 million units in 2017, a 10% y-o-y growth (Figure 4.19).[17] Reversible air-air pumps accounted for 48% of sales, followed by air-water (43%) and ground-source pumps (9%). Most purchases were in France (22%), Italy (16%), Spain (10%) and Sweden (10%).

Figure 4.19 European heat pump sales, 2012-17 (left), and shares of households with heat pumps (right)



Source: EHPA (2018), Market statistics online dashboards, www.stats.ehpa.org.

Scandinavian countries have the highest shares of household heat pump installations: in Norway, where 47% of households have them, air-air systems are the most economic choice for space heating, and the technology is fully accepted and recognised. Cumulative installations numbered 10.6 million units in 2017, an estimated 369 GW of flexible demand that can benefit smart grid power systems (EHPA, 2018; IEA HPT TCP, 2017).

[17] Data for Europe from the European Heat Pump Association (EHPA) include air-air heat pumps and cover Norway, Sweden, Finland, Estonia, Denmark, Switzerland, Italy, Austria, France, Portugal, Spain, Germany, the Czech Republic, the Netherlands, Belgium, Ireland, the United Kingdom, Lithuania, Poland, Slovakia and Hungary.

In China, where coal boilers are being replaced by heat pumps, a key driver of deployment is air pollution control. In a number of European countries, bans on gas- or oil-fired boilers, as well as stricter energy performance requirements for new constructions and refurbishments, are prompting the electrification of heating. In addition, the revised RED's heat target for 2030 is likely to drive further heat pump deployment, as are incentive schemes (capital grants, tax rebates, tax credits, etc.), building codes and special electricity tariffs for heat-pump heating. Heat pumps are also being increasingly used in larger-scale applications in district heating and in industry.

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5. RENEWABLE ENERGY TRENDS TO WATCH

Key questions

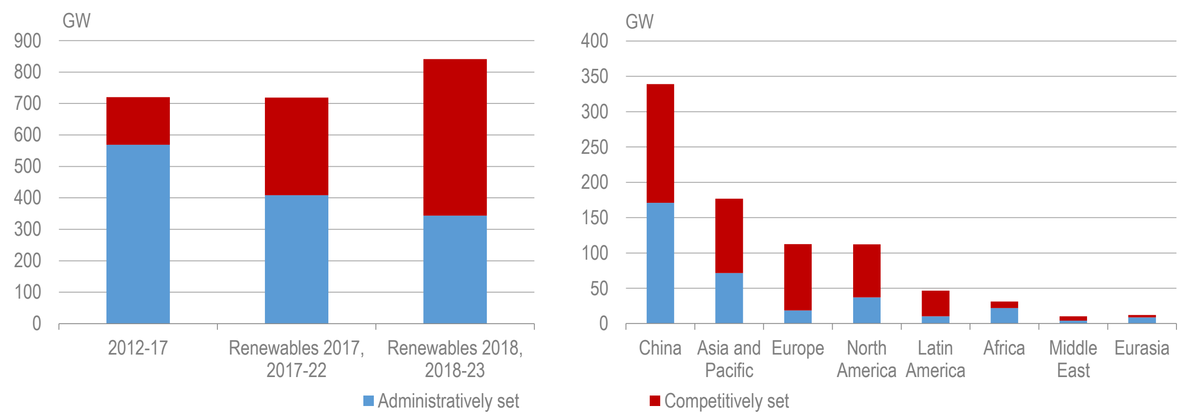
Whereas the previous chapter presented regional and technology forecasts for the electricity, transport and heat sectors, this chapter addresses 14 key questions to offer additional analysis of selected renewable technology and cost trends across various sectors:

1. Are auctions the primary policy mechanism driving utility-scale renewable electricity capacity expansion over the forecast period?
2. Have the prices from competitive auctions become the “new normal” prices for renewables?
3. Will renewables be cost-competitive with coal and gas plants by 2023?
4. Will distributed generation dominate solar PV growth over 2018-23, and will utilities lose a lot of revenue?
5. Why is solar PV capacity growing more quickly than that of any other renewable electricity technology?
6. Will system integration of renewables be a major challenge by 2023?
7. Can trade barriers hamper the growth of renewable energy technologies?
8. Will pumped storage hydropower capacity expand more quickly than stationary battery storage over the forecast period 2018-23?
9. Will concentrating solar power (CSP) contribute to global energy storage growth over the forecast period?
10. Is there scope for renewable heat technology costs to fall as they have for solar PV and wind?
11. Is there a future for co-firing biomass in the electricity sector?
12. Will energy from waste become the key form of bioenergy in Asia?
13. How competitive is biofuel production in Brazil and the United States?
14. Does household use of solid biomass-based heating affect air quality?

1. Are auctions the primary policy mechanism driving utility-scale renewable electricity capacity expansion over the forecast period?

Yes. For the first time, more than half of renewable capacity to be commissioned over 2018-23 will have fixed remuneration, set competitively, mostly through auctions. Compared with last year's forecast, the share of competitively set remuneration is higher, mainly because of the People's Republic of China's[1] policy transition from administratively set feed-in tariffs (FITs) to auction schemes for onshore wind and solar PV installations (Figure 5.1). China has already completed two utility-scale solar PV auctions for 8 gigawatts (GW) of capacity since 2016 and is expected to award larger capacities over the forecast period. In May 2018, the Chinese National Energy Administration announced the transition from FITs to auction schemes for onshore wind after 2020; as a result, competitive pricing is expected to drive almost half of utility-scale capacity deployment over 2018-23, especially for solar PV and onshore wind. Administratively set tariffs will continue to stimulate hydropower, offshore wind, bioenergy and CSP growth in China.

Figure 5.1 Utility-scale renewable capacity growth by remuneration type, 2018-23



Outside of China, competitive auctions drive two-thirds of renewable capacity expansion, but regional policy trends vary. In the Asia-Pacific region, India implements auctions for all utility-scale wind and solar projects, while many Association of Southeast Asian Nations (ASEAN) countries are transitioning towards tendering out renewable energy projects. Remuneration for most hydropower projects is set administratively, as investment and project development in many developing countries and emerging economies is dominated by publicly owned, vertically integrated companies. In the United States, a federal auction scheme does not exist, but wind and solar projects normally compete with one another to offer lower prices for long-term power purchase agreements (PPAs) to public and private utilities and corporations.

EU countries have been transitioning to competitive auctions for utility-scale projects since 2016, whereas Middle Eastern countries implement auction schemes, except Iran, which is responsible for one-quarter of the region's renewable capacity growth. In sub-Saharan Africa, South Africa awards projects through competitive tenders, but other governments in the region still regulate the remuneration of hydropower and geothermal plants. Meanwhile, auction schemes backed by multilateral development banks have emerged as a preferred policy to award new solar PV and wind capacity projects in many countries in the region, including Senegal, Zambia and Ethiopia.

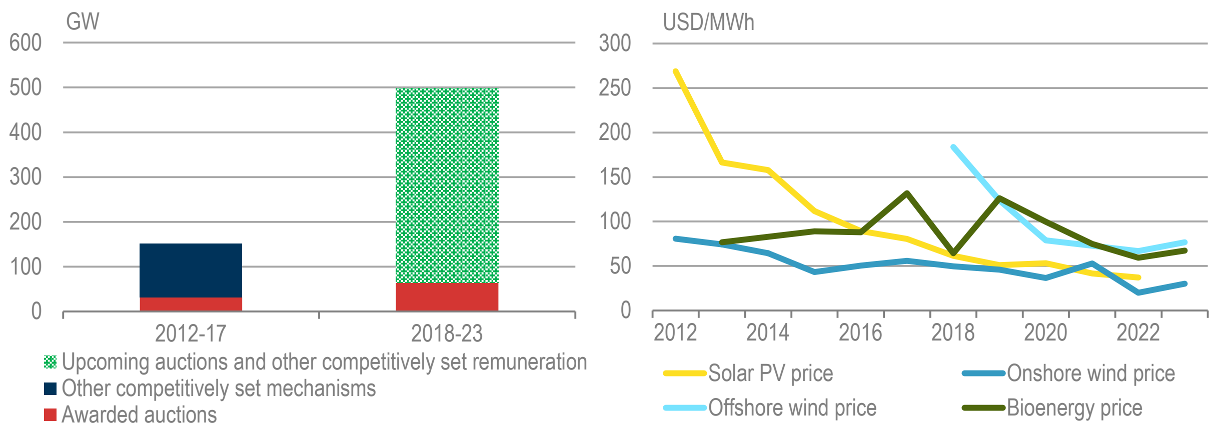
[1] Hereafter "China".

2. Have the prices from competitive auctions become the "new normal" prices for renewables?

Only partly. It is true that the use of competitive auctions has accelerated cost reductions for some renewable technologies, notably solar PV, onshore wind and offshore wind, establishing price benchmarks that are recognised worldwide. However, these prices cannot be consistently followed, as each country and technology has different resource potentials, financing conditions and auction designs. That said, overall trends show that recent bid prices for onshore wind and solar PV technologies for projects to be commissioned by 2023 range from USD 20 per megawatt hour (/MWh) to USD 50/MWh (Figure 5.2). This corresponds to a 45-50% reduction in contract price for both technologies from 2017 to 2022/23; for offshore wind, the decline is almost two-thirds.

It must be noted, however, that these auction prices are based on just a small portion of the total capacity to be commissioned under competitively determined remuneration schemes in the main-case forecast (Figure 5.2, left), so average prices may change with the announcement of new auctions. In addition, announced contract prices need to be verified as project delivery schedules and final costs may differ.

Figure 5.2 Awarded utility-scale, competitively remunerated renewable capacity (left) and average auction price by project commissioning date (right)



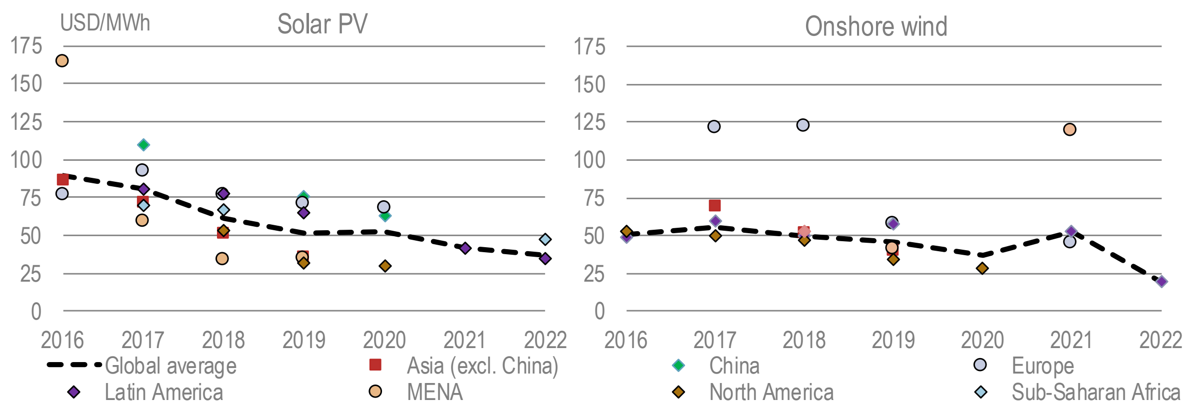
Notes: Other competitively set remuneration schemes include green certificate systems and competitive contract price-setting as part of the renewable portfolio standards or corporate PPAs. Auction prices are not levelised to take price escalations or other benefits such as tax incentives or split tariffs into account.

Source: IEA (2018a), *Renewable Auctions Database*.

Trends in regional average auction prices for solar PV and wind technologies reflect different tender designs and financing mechanisms in various countries. Asia (excluding China) and Latin America, led by India and Brazil, represent over half of auction-awarded capacity worldwide, influencing average prices for onshore wind and solar PV technology globally (Figure 5.3). High capacity factors, low-cost concessional financing and long-term government policies on auctions have been key factors in Brazil and Argentina's highly successful auctions. In India, however, developers' aggressive bidding strategies have resulted in tender cancellations or contract negotiations delaying some deployment.

In North America, Mexican green certificate and energy auctions have led to the lowest prices worldwide for both wind and PV technologies. These prices are, however, subject to hourly price adjustments, while additional revenues from merchant activities and bilateral PPAs may increase total project remuneration. In the Middle East, the sharp fall in contract price from 2016 to 2017/18 stems from solar PV projects in the United Arab Emirates, which underscores the impact of high resource availability and low-cost financing. Contract prices for China's recently announced solar PV auctions remain above the global average, mainly because of the relatively high FITs still available at the time of bidding. Access to concessional financing and robust auction design were instrumental in achieving low prices in Sub-Saharan Africa, mainly in South Africa and Zambia.

Figure 5.3 Average auction prices for solar PV and wind, by region and commissioning date



Notes: MENA = Middle East and North Africa. Prices are nominal; higher values for onshore wind in 2017-18 result from the United Kingdom's contracts for difference (CfD) auction, and in 2021 are associated with a delayed project from the Jordanian auction held in 2014.

Generation costs are expected to continue falling for solar and wind technologies over 2018-23. *Renewables 2018* expects offshore wind generation costs to decline over 40% in the next five years, followed by solar PV (25%) and onshore wind (6%). However, comparisons between levelised costs of energy (LCOEs) and auction prices remain an important challenge. Limited availability of information on contract-winning projects makes it difficult to state with certainty that these tender-determined prices are becoming the standard benchmarks for renewable generation costs.

There is little doubt that market competition in well-designed and transparent auction schemes is an effective trigger for significant cost reductions. This is demonstrated in Figure 5.4 (right graph), which compares FITs and auction-based projects commissioned in the same year in different countries and indicates cost reductions of 10-50%.

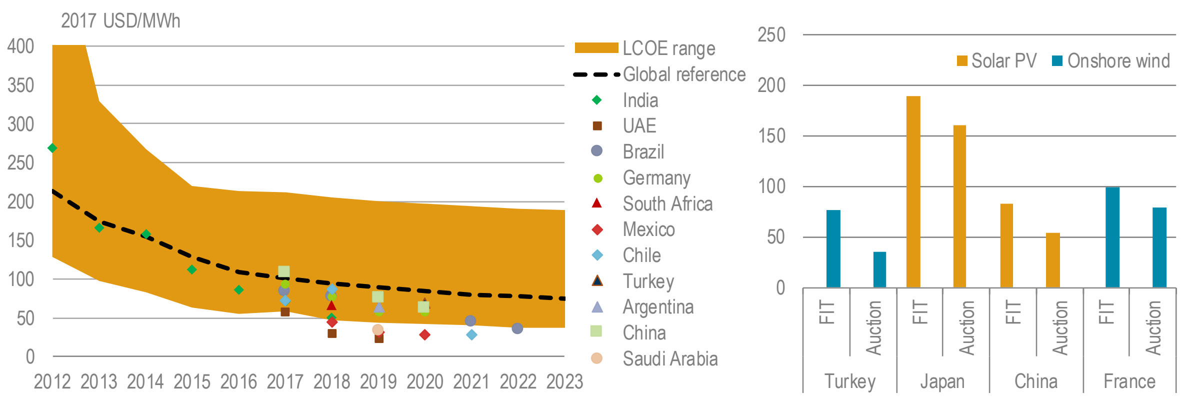
However, LCOEs generally tend to be higher than awarded auction prices, for three main reasons (Figure 5.4, left). First, auction prices may not always reflect full costs: for instance, grid connection costs are not included in offshore wind auctions in Europe (except in the United Kingdom), while they are fully included in this report's LCOE calculations. In addition, contracts may include price escalation clauses or split tariffs, as well as other benefits such as financing terms or tax conditions.

Second, the utility-scale PV market is currently dominated by China, the United States and Japan, where average PV generation costs are relatively higher due to high FITs in China and Japan, and elevated financing, administrative and regulatory costs in the United States. Moreover, some developers' aggressive bidding strategies to gain market shares could also widen the difference between LCOEs and announced bid prices.

Third, awarded auction prices currently reflect only a small portion of the market, including countries with exceptional resources and low financing costs – conditions that permit record-low prices. Average auction prices may rebound as auctions progressively cover the majority of new utility-scale installations worldwide.

Over the forecast period, more complex business models are expected to emerge, to complement fixed remuneration received through auctions with additional revenues from corporate PPAs, merchant activities or hybridisation with storage to provide firm capacity. This emerging trend is expected to make it even more difficult to compare auction prices with LCOEs.

Figure 5.4 Global average LCOEs and auction results for utility-scale PV by commissioning date (left) and FITs versus auction prices for selected countries, 2017 (right)



Notes: UAE = United Arab Emirates. All LCOE assumptions are country-specific. LCOE ranges reflect high and low assumptions for inputs such as investment costs, full-load hours and the weighted average cost of capital.

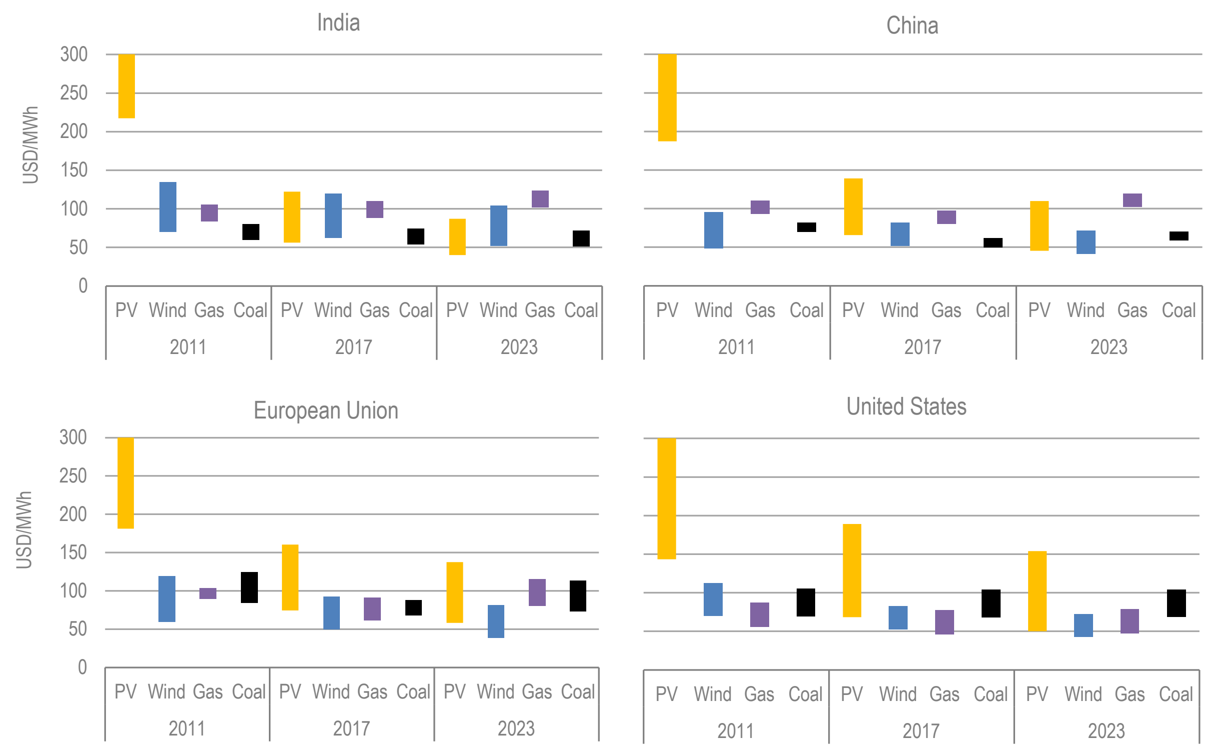
Source: Historical LCOE analysis based on investment costs from IRENA (2018b), *Renewable Cost Database,* dataset provided to the IEA.

3. Will renewables be cost-competitive with new coal and gas plants by 2023?

Increasingly yes, but not everywhere. Over 2018-23, continuous drops in wind and solar PV costs will improve their competitiveness, such that onshore wind and solar PV projects with high capacity factors and low-cost financing are expected to attain levelised electricity generation costs comparable with or lower than those of new fossil fuel plants in an increasing number of countries. In the absence of a carbon price, however, marginal electricity generation costs of existing fossil fuel plants, especially coal-fired, generally remain lower than for renewables, except existing hydropower assets.

In 2017, the LCOEs of most solar PV and onshore wind plants were lower than for new natural gas plants in India and China, where gas prices remain high despite relatively low investment costs (Figure 5.5). However, generation costs for coal plants were still lower than for wind and solar PV installations in both countries. In the United States, the European Union and Brazil (and some other Latin American countries such as Chile and Uruguay), LCOEs of onshore wind projects with high capacity factors and competitive financing were already lower than for new coal plants. In Japan, on the other hand, wind and solar LCOEs remain high due to very high investment costs and are not comparable to new gas- and coal-based generation despite relatively high fuel costs.

Figure 5.5 LCOE ranges for new utility-scale onshore wind, solar PV and coal and gas plants by commissioning date, 2011-23



Notes: Wind = onshore wind. All values are in 2017 USD. LCOE ranges reflect high and low assumptions for inputs such as investment costs, full-load hours and the weighted average cost of capital; all LCOE assumptions are country-specific. Gas= new CCGT plants, Coal=new supercritical coal plants. Ranges for coal plants reflect 40-70% capacity factors. Ranges for gas plants reflect 30-70% capacity factors for all countries/regions. Fossil fuel LCOEs include a carbon dioxide (CO_2) price in countries where a policy has been implemented or announced. Please see the analytical framework section at www.iea.org/renewables2018.

Sources: Historical LCOE analysis for renewables based on investment costs from IRENA (2018b), *Renewable Cost Database*; fossil fuel LCOE assumptions based on New Policies Scenario (NPS) assumptions in IEA (2018e forthcoming), *World Energy Outlook 2018.*

On an LCOE basis, the competitiveness of wind and solar PV technologies is expected to improve by 2023 with continuous investment and declining operation and maintenance costs. Meanwhile, natural gas and coal prices are anticipated to increase in many countries/regions over the forecast period, resulting in higher generation costs for both new and existing plants. In India and China, generation costs for onshore wind and solar PV projects are expected to become increasingly comparable to (or even lower than) coal generation, while in high-resource areas some onshore wind and solar PV projects with competitive financing could achieve lower LCOEs than coal-fired generation by 2023. In the European Union and Brazil, onshore wind becomes the least costly source for new power generation, with solar PV closing the gap rapidly.

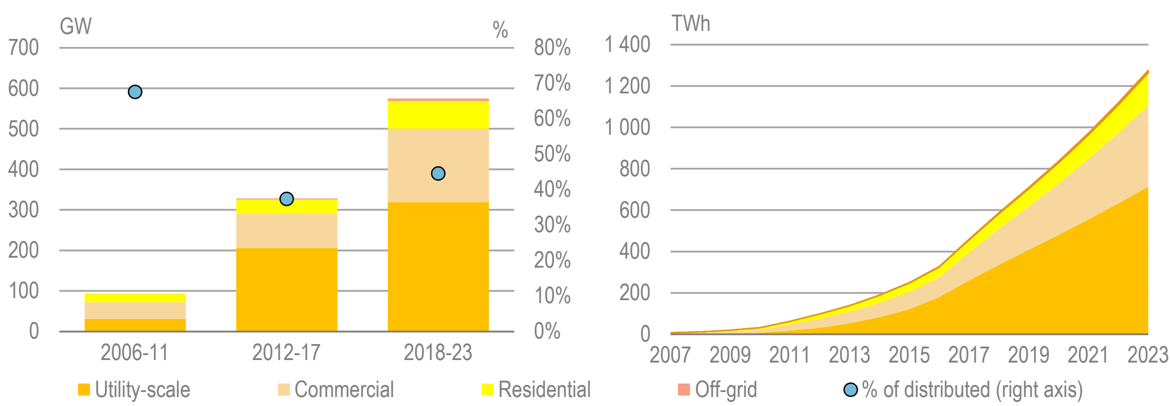
Finally, it is important to remember that LCOEs are not the sole indicator of competitiveness between fossil fuels and renewables. Investment decisions in new power-generating capacity involve a complex decision-making process that considers various risks and benefits – not only LCOEs – and are strongly dependent on specific market and regulatory frameworks. System cost and benefit assessments are particularly important to comprehensively evaluate the competitiveness of renewable technologies.

These assessments are complex and depend on market/country context. In addition, they must consider a wide array of factors relevant to system value. These include the penetration rate of renewables, available flexibility (in terms of grid and interconnection strength, other dispatchable supply, storage and demand-side response), the price of externalities and import dependency. Such detailed analysis is outside the scope of this report and will be published in the forthcoming IEA World Energy Outlook 2018.

4. Will distributed generation dominate solar PV growth over 2018-23, and will utilities lose a lot of revenue?

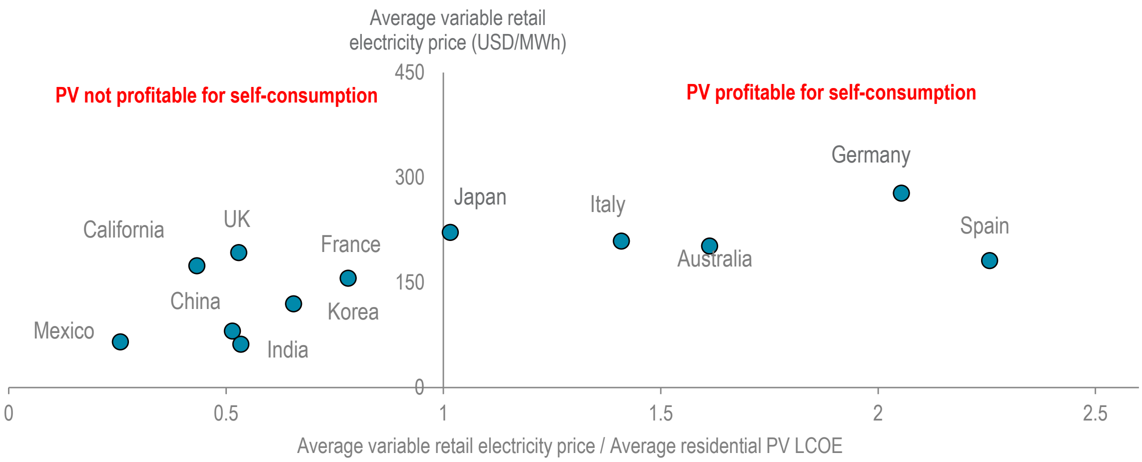
Shares of commercial/industrial and residential applications in both solar PV capacity growth and electricity generation are expected to increase over 2018-23 (Figure 5.6). In 2017, distributed PV accounted for 38% of new capacity additions, up from 25% in 2016 owing to expansion in China. Over the forecast period, almost half of PV capacity growth is in distributed applications, of which commercial and large-scale industrial projects account for 70%, residential systems another 28% and off-grid installations 2%. They are estimated to generate over 500 terawatt hours (TWh), or 40% of global solar PV electricity by 2023. This means that homes, businesses and large-scale industrial applications will generate almost 2% of global power output at the end of the forecast period.

Figure 5.6 Solar PV capacity growth and total generation, 2006-23



Retail electricity prices, generation costs of distributed PV (and behind-the-meter storage, when relevant), remuneration of excess (or all) generation, and economic incentives are the four main variables that companies and individuals use to assess the economic attractiveness of distributed PV generation. These variables change at the national and sub-national levels. In 2017, the variable portion of electricity prices was already 1.5 to almost 2.5 times higher than the average generation costs of residential PV systems in European countries such as Germany, Spain and Italy (Figure 5.7). In these markets, the value of self-consumption (in terms of electricity bill savings) is high if there is a good match between consumption patterns and PV electricity generation, which is more likely in Southern Europe. However, the economic attractiveness of self-consumption business models remains limited in countries where retail electricity prices are relatively low, such as in India, China and Mexico. In these countries, financial incentives and remuneration schemes in which surplus electricity is injected into the grid are key factors in assessing the profitability of distributed PV projects.

Figure 5.7 Residential electricity prices compared with average residential LCOE, 2017



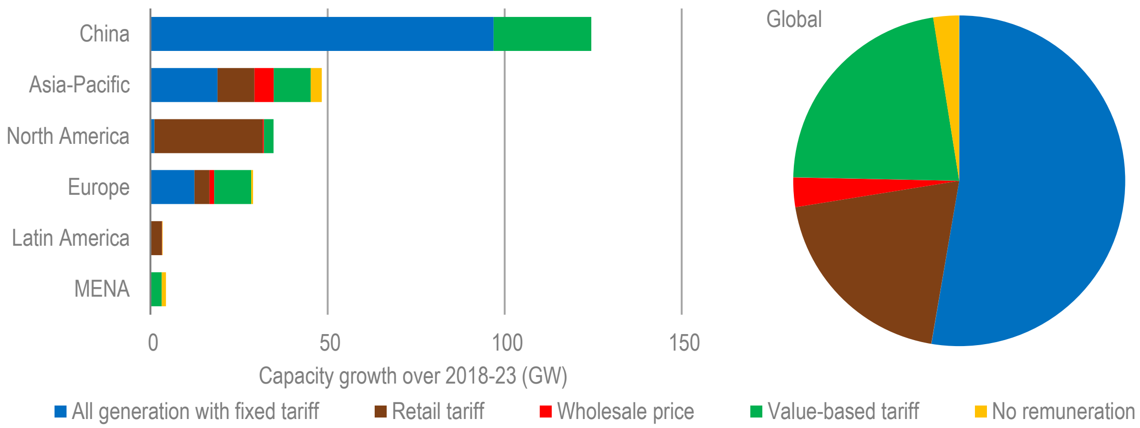
Sources: Average retail prices for Organisation for Economic Co-operation and Development (OECD) countries based on IEA (2018c), *World Energy Prices*; LCOE calculations based on average investment costs from IRENA (2018b), *Renewable Cost Database.*

The uptake of commercial and residential solar PV installations is also highly dependent on how surplus electricity is remunerated. In general, home and business owners consume a portion of what they generate. For residential applications, self-consumption rates can range from 0% (if the policy offers a 'sell all, buy all' model that remunerates all PV generation with a fixed tariff) to 15%. The share could rise to 50% in commercial applications, depending on the size of the system and overall electricity demand profile. Remuneration of electricity from distributed applications currently ranges from 0 to values higher than retail electricity tariffs, depending on national or sub-national policies.

Globally, over half of the distributed PV generation capacity due to come online in 2018-23 is anticipated to receive fixed tariffs that could be higher or lower than retail tariffs. One-third of the distributed capacity is expected to fall under classic net metering schemes, wherein owners receive retail tariffs for surplus electricity (Figure 5.8). In some countries, surplus PV electricity is bought at a value-based tariff, whereby utilities or regulators estimate the value of PV generation based on avoided generation capacity expansions and any additional costs or benefits to the system or society (grid integration costs, CO_2 reduction value, etc.). Typically, value-based tariffs are between retail tariffs and wholesale electricity prices, usually closer to the latter. Remunerating excess electricity at wholesale prices is uncommon, as is distributed capacity with no remuneration of excess electricity (Figure 5.8, right), because expanding distributed PV capacity is challenging if remuneration for surplus electricity is low or non-existent.

China is expected to be the largest distributed generation market globally in the next five years, with large-scale industrial applications dominating growth. The Chinese government offers two types of remuneration for distributed generation (Figure 5.8, left). Fixed tariffs, which vary across provinces, are currently much higher than both residential and commercial electricity prices in many provinces, and most distributed applications are expected to receive a fixed tariff over the forecast period, while 20% utilise the self-consumption and value-based tariff, which consists of the wholesale price plus distributed generation tariff for excess electricity fed into the grid. However, the share of self-consumption models may increase with the reduction of incentives for distributed solar PV applications. In the Asia-Pacific region, governments administer various remuneration schemes in the major distributed PV growth markets of India, Japan and Australia. In India, commercial applications mostly receive either wholesale prices or value-based tariffs, as the implementation of state-level net metering policies remains limited. In Japan, commercial applications are remunerated with a fixed tariff higher than the retail rate, while value-based tariffs are used in the majority of Australian provinces.

Figure 5.8 Policies for remuneration of all or excess generation from distributed PV generation capacity, 2018-23

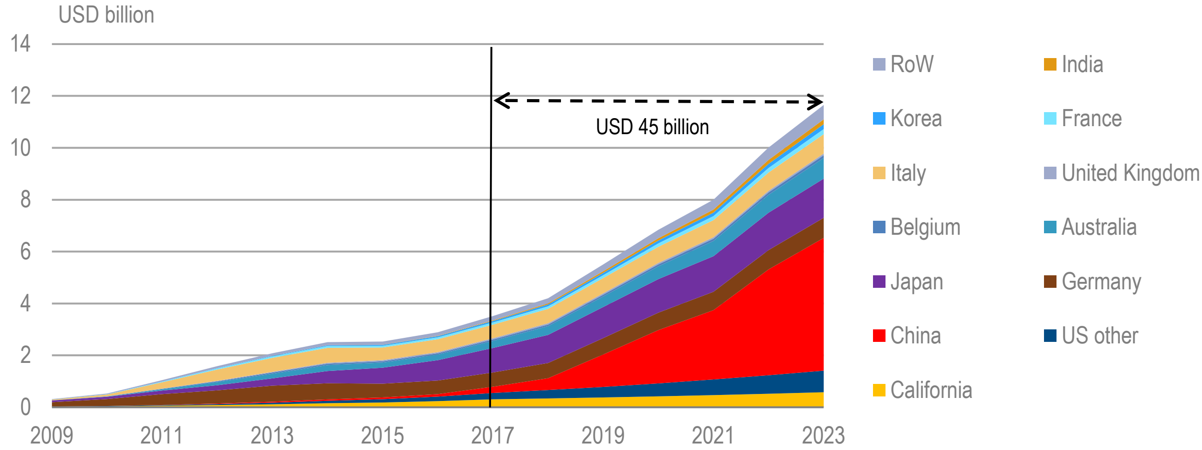


In North America, the United States dominates growth, as annual retail credits through net metering schemes remain common in many provinces or states, including California. In Europe, commercial and residential segments usually have different remuneration schemes. Fixed tariffs dominate residential PV markets in Germany, France and the United Kingdom, while there is no remuneration for surplus generation in Spain and Italy. For larger commercial installations, European countries mostly implement schemes using value-based or fixed tariffs, which are usually lower than retail electricity prices.

The impact of distributed generation on utility and retailer future revenues is often discussed in the context of economic efficiency and fairness among different categories of customers. Utilities usually advocate increasing fixed elements of the electricity bills, which represent 5-15% of the total tariff for residential customers in many countries, and sometimes up to 50% for some large commercial rate payers. In 2017, utilities were unable to collect an estimated USD 3.5 billion in revenues (excluding tax) due to consumption of self-generated solar PV electricity in residential and commercial segments. This sales loss is expected to more than triple to almost USD 12 billion annually by 2023 as distributed generation expands rapidly in China, the United States, the European Union and Japan (Figure 5.9). The global sales loss in 2023 is estimated at less than 0.3% of total retail bill collection revenue today, and the cumulative retail value of self-consumption over 2018-23 is estimated at USD 45 billion. However, utilities in some countries, states or provinces will be more affected than others depending on the amount of local distributed PV generation.

Utilities can avoid and minimise these losses by adapting their business models to capture potential revenues arising from greater consumer-level participation in the power sector, including through self-consumption. With their extensive customer relationships, utilities are very well placed to provide services such as the installation and management of distributed solar PV and behind-the-meter storage, energy demand management, and the aggregation and trading of distributed electricity resources on power markets, among others.

Figure 5.9 Retail value of self-consumption by residential and commercial PV applications

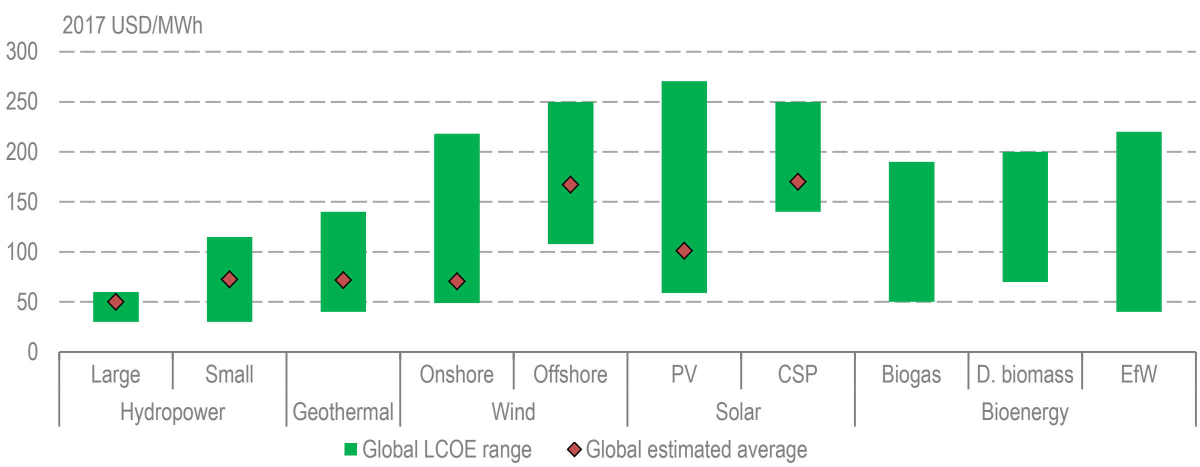


Note: RoW = rest of world.

5. Why is solar PV capacity growing more quickly than any other renewable electricity technology?

Solar PV already accounted for over 37% of global renewable capacity expansion over 2012-17, and the share is expected to increase to over 50% in the next six years owing to policy support and continuous cost reductions. Yet, solar PV is not the lowest-cost renewable energy technology today: in 2017, global average generation costs of hydropower (small- and large-scale), onshore wind, geothermal and some bioenergy applications were lower than for solar PV (Figure 5.10). However, solar PV generation costs are projected to decline a further 15-40% over 2018-23 (depending on the country), closing the cost gap with other renewable technologies.

Figure 5.10 Global average LCOEs for renewable technologies, 2017



Notes: D. biomass = dedicated biomass.

Source: Historical LCOE analysis based on investment costs from IRENA (2018b), *Renewable Cost Database*, dataset provided to the IEA.

However, generation costs and policy support only partially explain the exponential growth in PV capacity, as other renewable technologies face deployment challenges despite their lower generation costs while solar PV benefits from unique advantages:

- **Size:** Solar PV installations can range from 2- to 3-watt off-grid applications to gigawatt-scale power plants. This wide range of application options increases the number of possible investors, from individuals to large-scale utilities with multi-billion-dollar assets. Indeed, this application flexibility makes PV the fastest-growing renewable technology: relatively small-sized systems, residential, commercial/industrial and off-grid applications together account for almost 43% of global PV expansion in the next five years. If distributed generation capacity is excluded from this report's main case scenario, utility-scale solar PV growth over 2018-23 is very close to that of wind.
- **Shorter pre-development process:** Solar PV plants do not require long weather measurement processes. Usually, the environmental assessment remains simple, and is shorter than for wind and hydropower installations in many countries. In addition, it is relatively easy to obtain construction permits, as PV plants do not have a height component and social acceptance issues are limited in comparison with other renewables.
- **Modularity and relative simplicity of construction:** Solar PV installations of any size are generally modular, with a relatively simple construction process. The usual construction time for utility-scale projects is from six months to one year, and often only one day for residential applications. For instance, China installed almost 30 GW of capacity in just four months (April-July 2017).
- **Low operation and maintenance costs:** Solar PV plants have among the lowest operation and maintenance costs of all renewable electricity technologies because of their small number of mechanical moving parts. Annual operational and maintenance costs are usually around 1% of total investment costs, which could range from USD 10 per kilowatt (/kW) to USD 15/kW/year, 30-50% lower than for onshore wind.

In contrast, various technology-specific economic and non-economic challenges prevent faster uptake of other renewables:

- **Onshore wind** generation costs are currently lower than for solar PV in many countries due to relatively high full-load hours. However, onshore wind plant development and permitting processes are usually longer (two to four years). Environmental impact assessments are often lengthy, as project impacts on birds and radar systems need to be assessed by multiple stakeholders. For projects with larger turbines, additional roads may have to be commissioned to transport them, and construction could take longer and be more challenging. Lack of social acceptance of wind turbines is also an important issue, especially in Europe, where it slows down or halts project development in some countries.
- **Hydropower** is the most cost competitive renewable technology on a levelised generation cost basis, but its development, especially for large-scale projects, has slowed down in some countries and regions. Environmental impact assessments and lack of social acceptance still impede new large-scale project development globally, as do costly grid expansions in some countries. Projects already under construction in Latin America and ASEAN countries have been delayed by these issues, which has also raised investment costs.

- **Bioenergy** plants benefit from economies of scale, putting the cost of electricity generation from larger-capacity plants at the lower end of the scale. However, larger systems require more time for development and to obtain all necessary permits. Most biomass projects are also bespoke (i.e. made to order), which limits project replication and increases developer risk. Fuel costs are the major component of generation costs for bioenergy plants, and economical fuel supply chains cannot always be established despite resource availability; in addition, in certain markets fuel costs have escalated after commissioning of the project. For EfW, waste management frameworks to collect and pre-process waste are necessary to ensure a steady fuel supply, while lack of social acceptance can constrain deployment. Finally, in terms of policy support, biomass technologies have been included in renewable energy auctions in far fewer countries than solar PV has been. The complex, ongoing debate on the sustainability of bioenergy causes policy makers to exercise caution.
- **Geothermal** resource availability is limited, especially in high-temperature areas, but once the project is operational, generation costs can be lower than for wind and solar technologies because geothermal plants operate at high (50-90%) capacity factors. However, pre-development processes (mostly well-drilling) are lengthy, and unsuccessful drilling could represent at least 40% of the costs associated with resource confirmation. Debt financing is usually limited in the pre-development stage due to elevated risks, as de-risking policies for this early stage of project implementation are often not available in many resource-rich countries.

6. Will system integration of renewables be a major challenge by 2023?

System integration of renewables is already a major challenge, and has been for some time. But it is a problem that can be successfully remedied in a cost-effective manner.

Several countries have experienced decelerating variable renewable energy (VRE) deployment due to system integration concerns or periods of high curtailment, even during the early days of VRE expansion. Ireland, for example, put a moratorium on new wind developments following major concerns about the “security and stability of the power system” in 2003, when wind technology contributed 2% of annual generation. Challenges were subsequently analysed in a systematic manner, and a strategy for resolving them was designed and implemented. As of 2017, Ireland had 25% wind power in its generation mix and is moving towards 39% by 2023 while maintaining reliability and without significant additional costs. Similarly, curtailment levels of the Electricity Reliability Council of Texas (ERCOT) peaked around 20% in 2009 due to wind power capacity increasing more quickly than required grid infrastructure. Since then, the grid has been built out and curtailment has fallen to a healthy level (below 2%).

Wind and solar PV are technically different from conventional forms of electricity generation. Their maximum instantaneous output depends on how much wind and sunlight are available at any given moment, which makes their output variable and only partially predictable. VRE can be deployed at very different scales – from large offshore parks to small home systems. Plant location is constrained, however, because sites with favourable wind and solar resources may not be where the electricity is needed. In addition, their technical response characteristics, especially during grid disturbances, are determined by control software settings rather than by inherent technical design.

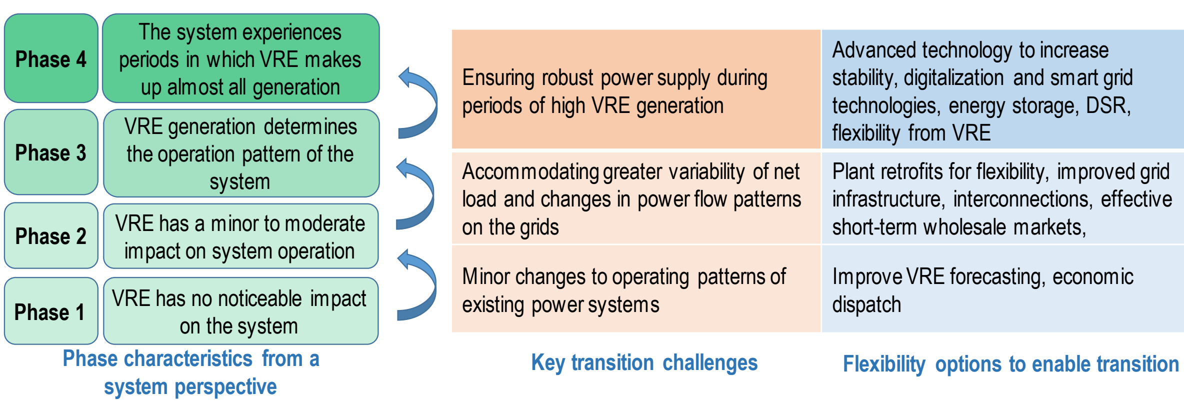
These properties – variability, partial predictability, and location constraints – can make it difficult for power systems to accommodate higher amounts of VRE. What is needed to manage system integration is power system flexibility, which encompasses all system components that facilitate the reliable and cost-effective management of variability and uncertainty in both supply and demand. Maintaining a reliable supply of electricity requires that supply and demand be balanced continuously across all timescales, from sub-seconds to years – it is thus useful to consider flexibility along these timescales.

Previous International Energy Agency (IEA) analysis has identified different phases of VRE integration (IEA, 2018d). They are characterised not only by a specific penetration level, but by the main integration issues and challenges, covering technical, regulatory, market and institutional aspects. It is important to note that a variety of system-specific factors influence how much an increase in VRE will affect overall system flexibility.

- **Phase 1**: The first set of VRE plants are deployed, but they are basically insignificant at the system level; effects are very localised, for example at plants' grid connection points.
- **Phase 2**: Changes between load and net load become noticeable, but the existing system is flexible enough to achieve system integration.
- **Phase 3**: Greater swings in the supply-demand balance prompt the need for a systematic increase in power system flexibility beyond what can be relatively easily supplied by existing assets and operational practices.
- **Phase 4**: VRE output provides the majority of electricity demand in certain periods, requiring both operational and regulatory modifications. Operational changes involve power system stability, determining the way the power system responds following supply or demand disruptions, and regulatory changes may include new rules for VRE to provide system services.

Moving smoothly from one phase to the next requires that measures become increasingly interrelated and complex. Ultimately, a systematic transformation of the electricity system, and the wider energy system overall, is required (Figure 5.11).

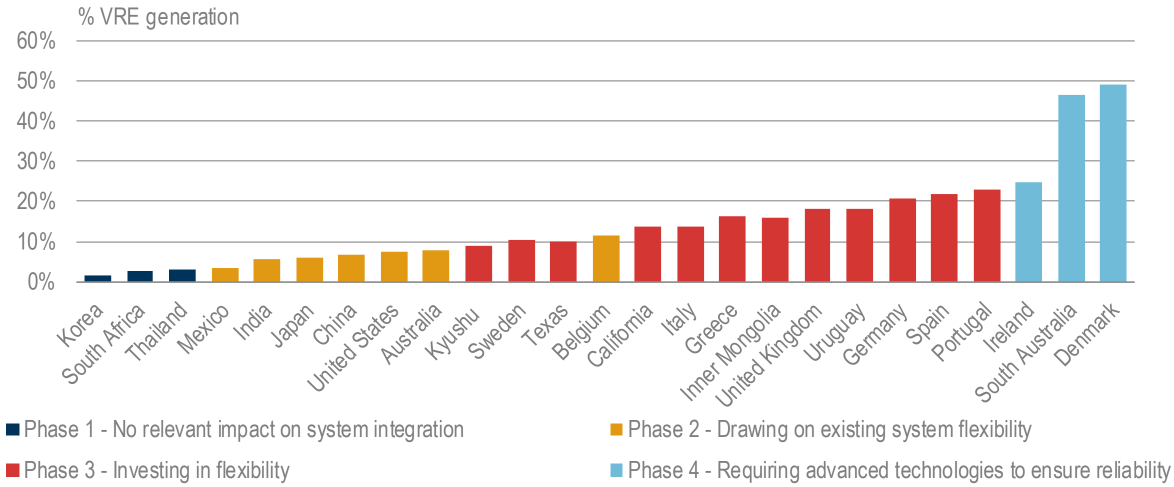
Figure 5.11 System integration phases, transition challenges and flexibility measures



Note: DSR = demand-side response.

Further VRE deployment beyond Phase 4 to Phases 5 and 6 is possible, but requires the electrification of other end-use sectors, seasonal storage and the use of synthetic fuels such as hydrogen (IEA, 2018d). Most countries are presently at Phase 1 or 2 but are striving towards higher phases (Figure 5.12).

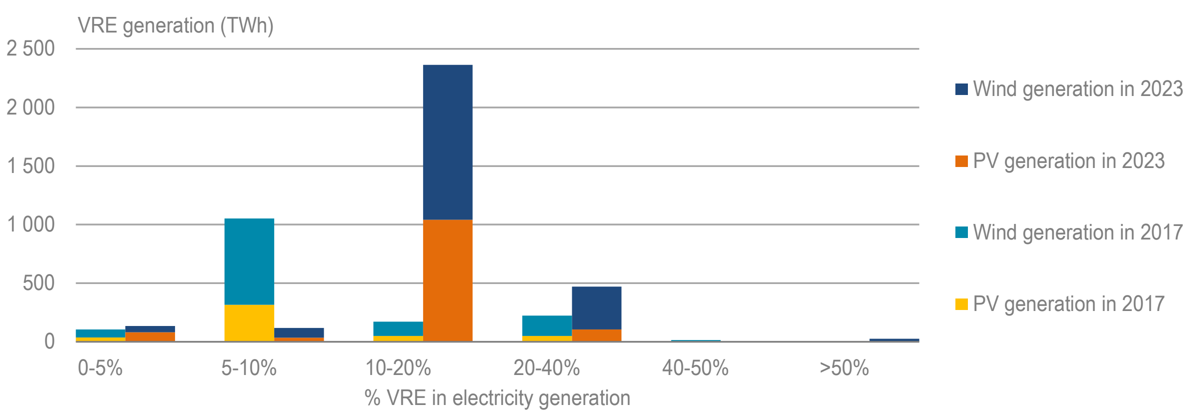
Figure 5.12 Selected countries by integration phase and share of VRE, 2017



Today, China – the world's largest wind and solar market – is facing a number of substantial integration challenges. However, curtailment levels have been declining and several measures have been instituted to further alleviate challenges. It is expected that a number of other countries will also face system integration challenges in the next six years, which will likely lead to some instances of temporarily slowed deployment and periods of elevated curtailment.

That said, projections have become more dependent on countries successfully addressing system integration challenges for two main reasons. First, in 2017 the majority of VRE generation occurred in countries with shares of 5-10% annually (Figure 5.13). In this range, system integration challenges are relatively modest and can be handled through several straightforward options. Once shares exceed 10%, however, a more systematic approach to system integration is required. Second, VRE expansion has become more reliant on solar PV technology, and at higher shares of VRE, integration challenges tend to occur sooner for technologies with lower capacity factors. Hence, the shift from wind to solar capacity additions makes system integration measures even more necessary.

Figure 5.13 Share of variable renewables in global electricity mix



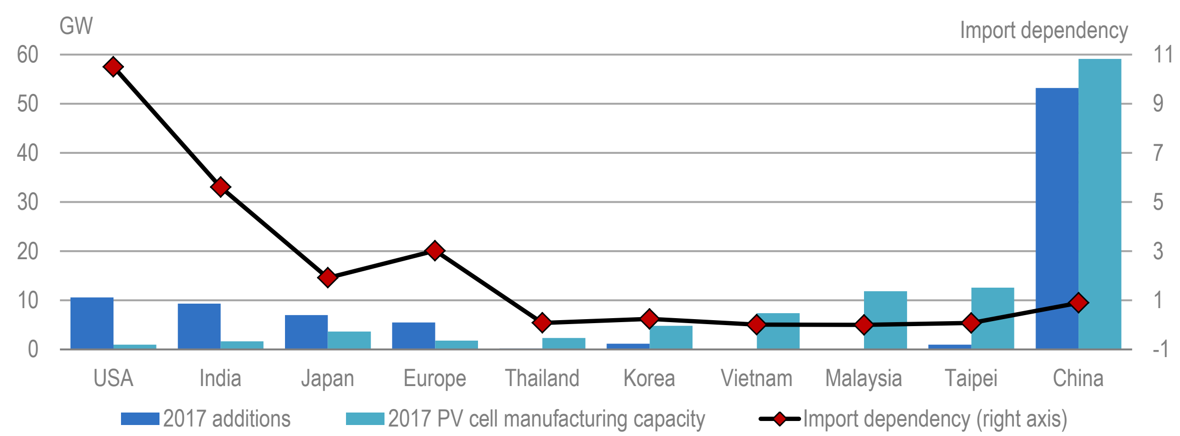
Shares of VRE in many countries are forecast to be much greater in 2023 than in 2017. They are expected to rise from 5-10% to predominantly 10-20% annually by 2023, and countries with annual VRE generation of 20-40% will also increase significantly (Figure 5.13). The number of countries with 10-20% VRE generation is expected to double between 2017 and 2023 (from 15 to 30 countries), and those with a 20-40% share are also expected to double.

7. Can trade barriers hamper the growth of renewable energy technologies?

Yes. Trade restrictions can directly and indirectly impact the availability and price of renewable energy equipment and services in both importer and exporter countries. Depending on their type, level and geographical coverage, basic trade restrictions such as import tariffs, safeguard duties and local-content requirements can result in higher prices for relevant products and services in importing countries, especially in the short term, and may adversely affect deployment.

The solar PV industry was subject to various waves of trade restrictions over 2012-16, with the European Union and the United States imposing duties on Chinese module imports. Over the same period, module prices declined almost 40% owing to rapid growth in supply as the solar PV manufacturing industry expanded both within and outside China, especially in Southeast Asia (Thailand, Viet Nam, Malaysia and Korea). However, PV manufacturing in the United States and Europe has not expanded in the past five years and their import dependency therefore remains high (Figure 5.14). At the same time, PV demand in China has grown exponentially since 2015 because of generous FITs. In 2017, China held 60% of both global PV demand and solar cell manufacturing capacity. Outside of China, the United States, India, Japan and Europe remained major demand centres but could only meet 10-50% of their needs through domestic production.

Figure 5.14 PV cell manufacturing capacity, demand and import dependency



Note: Import dependency is calculated by dividing local annual PV capacity additions by local solar cell manufacturing capacity. The higher the indicator, the higher the import dependence.

Recently announced trade restrictions may have direct and indirect implications for solar PV and wind technology markets. In 2018, the United States imposed an import tariff on commercial PV modules, at an initial rate of 30% and decreasing to 15% by 2021, and covering all major exporters. These tariffs are expected to raise module prices in the United States in the short term. In July 2018, India introduced a 25% safeguard duty on solar cells from China and Malaysia until July 2019, when the duty will be reduced to 20% for six months and then to 15% for the final six months ending in January 2020. Developers are expected to factor in additional costs associated with the duty in the upcoming auction bids.

Some companies announced investments in new manufacturing capacities in both the United States and India, but it remains to be seen how many of these projects will be realised, especially given the PV oversupply resulting from lower demand in China and recent module price declines. Also, the adverse effects of import tariffs are not only limited to the importing country: in Korea, Malaysia and Viet Nam, which were major exporters of solar PV modules to the United States in 2016, manufacturers' revenues are expected to drop significantly because 50-80% of their manufacturing capacity was devoted to US exports.

Trade restrictions on materials and equipment used to produce renewable technologies may also have price implications for importing countries. For instance, the US administration approved a 25% tariff on imported steel and 10% on aluminium in June 2018 because the US steel trade deficit had grown to over 300% in 2017. The tariff may indirectly impact wind turbine and solar PV module production, however, as steel and aluminium are important input materials: wind turbines towers can represent 20-30% of the overall cost and are usually made of steel, while steel and aluminium are used in mounting structures for solar PV installations.

Furthermore, trade policy impacts are not limited to renewable electricity technologies. Import tariffs and anti-dumping duties have been employed in biofuel transport markets for several years, and although most biofuels produced are consumed domestically to satisfy national mandates, exports are also important for some countries. For both Argentina and Indonesia, for example, biodiesel exports are a key production driver; in 2017, however, the US introduction of anti-dumping duties on biodiesel imports from these countries means they are now uneconomic. The resultant shortfall is likely to be filled by higher domestic production as well as potentially higher-cost imports from other locations. Conversely, the removal of EU anti-dumping duties on biodiesel imports from Argentina and Indonesia following an appeal to the World Trade Organisation, leading to resumption of imports from these countries, will likely constrain output of the least-competitive European biodiesel producers.

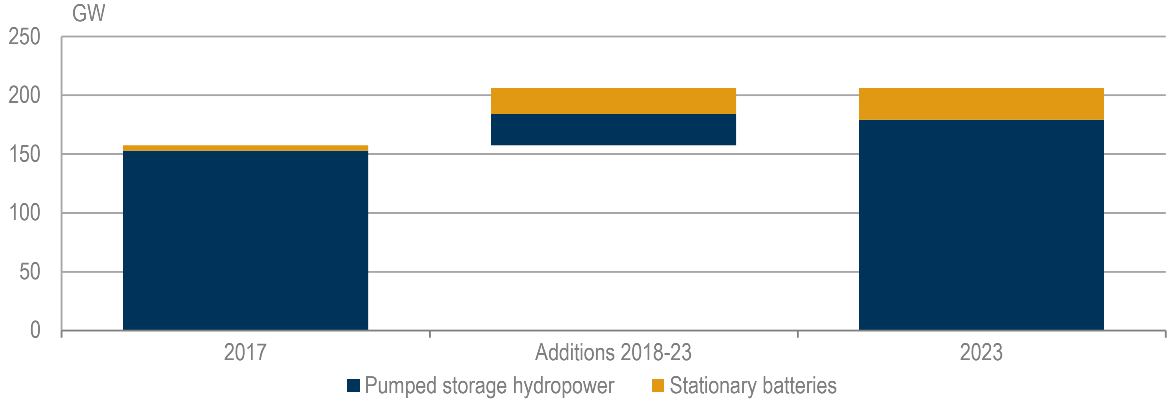
8. Will pumped storage hydropower capacity expand more quickly than stationary battery storage over 2018-23?

Over 2018-23, more pumped storage hydropower (PSH) plants are expected to be installed for global electricity storage[2] than stationary battery storage technologies deployed: PSH capacity is expected to increase 26 GW, while stationary battery capacity expands only 22 GW (Figure 5.15). Although overall cumulative installed storage capacity remains dominated by PSH, annual additions of stationary batteries are expected to overtake PSH by 2023 due to rapid cost reductions and technology progress.

However, comparing PSH and batteries based on storage volume, i.e. the amount of electricity they can produce, indicates a wider gap. The current storage volume of PSH plants is estimated at 1 500 GWh, whereas batteries amount to just 7 gigawatt hours (GWh) (Lempérière and Vigny, 2012).

[2] Electricity storage capacity in this section refers only to pumped storage hydropower and stationary batteries, including behind-the-meter capacity. Although other technologies such as reservoir hydropower, compressed air, flywheels, and hydrogen offer storage applications, they are not part of this analysis because of data unavailability.

Figure 5.15 Cumulative installed storage capacity (left) and annual additions, 2018-23 (right)



Note: Stationary batteries include utility-scale and behind-the-meter batteries.
Source: IEA analysis based on BNEF (2017).

Where will pumped storage hydropower growth come from?

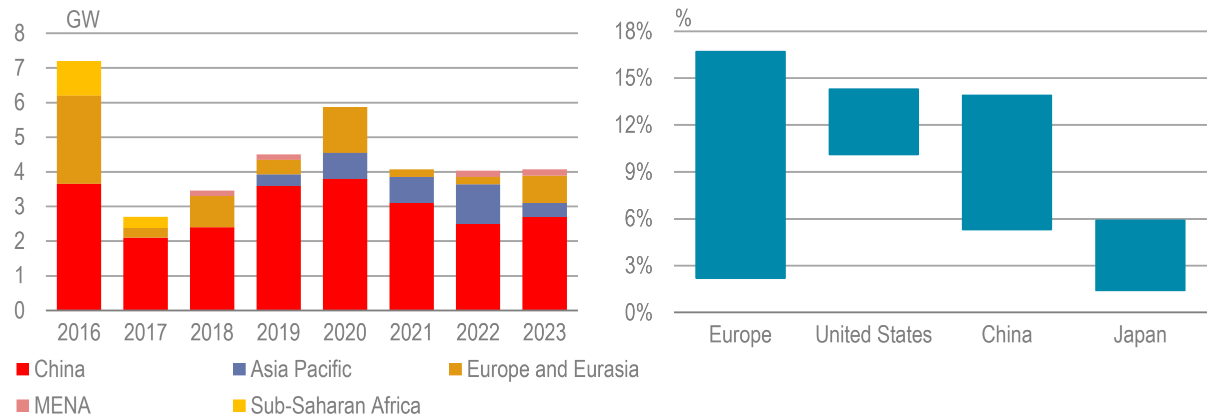
Global PSH additions declined to 2.7 GW in 2017, returning to the 20-year annual average after a record 7.2 GW[3] in 2016 resulted from exceptionally high deployment in China and Europe. China continued to lead global growth in 2017, accounting for over 78% (2 GW) of new commissioned units. As a result, China attained 29 GW of cumulative capacity, surpassing Japan to become the country with the most PSH capacity installed. By the end of 2017, global cumulative installed capacity had reached 153 GW, i.e. 12% of total hydropower capacity, with over 80% of it located in Europe, China, Japan and the United States.

In the next five years, PSH capacity is forecast to increase almost one-fifth (26 GW), mostly in response to greater needs for system flexibility to integrate variable renewables in China, Asia-Pacific countries, Europe and the MENA region (Figure 5.16). The forecast is revised up from *Renewables 2017* due to recent project developments in China, Australia and India. However, financing new PSH projects and operating existing ones profitably remain key challenges, particularly in markets in which revenues from energy arbitrage are uncertain, grid fees exist, and/or remuneration mechanisms that value the system services provided by PSH are lacking.

The largest growth happens in China, which is expected to install 18 GW in the next five years to meet its 13th Five-Year Plan (FYP) target of 20 GW by 2020. The main driver for PSH development in China is the increased need for system flexibility, particularly to reduce wind electricity curtailment and optimise coal and nuclear plant operations. Due to current regulations that consider PSH part of the transmission system rather than a generating asset, most PSH capacity growth is expected to come from China's state-owned grid companies at sites earmarked in network expansion plans. As such, the pace of PSH capacity expansion in the next five years will depend on the pace of project implementation and network upgrades by the grid companies.

[3] Global annual PSH additions for 2016 were revised upwards from the 5.8 GW quoted in *Renewables 2017* to reflect revisions to Portugal and Switzerland's official statistics for installed capacity in 2016 submitted to the IEA.

Figure 5.16 Annual PSH capacity additions by region (left) and range in capacity factors over 2000-16 (right)



Note: Europe's capacity factor ranges are based on seven selected markets that represent over three-quarters of Europe's installed PSH capacity.

Source: PSH capacity based on an IEA unit-level capacity database.

Europe's PSH capacity is expected to grow 2.8 GW by 2023 from additions in Switzerland, Portugal, Austria, the United Kingdom, and Germany. Suitable topography and a need for system flexibility to balance increasing wind and PV generation are the main drivers for growth. However, the economic attractiveness of PSH in the European market is a key challenge to deployment due to rising uncertainty over the business case for energy arbitrage and insufficient alternative revenue streams from other markets such as ancillary services and balancing or capacity markets. Most growth is therefore expected to come from utilities with majority state ownership.

Outside of China and Europe, the Asia-Pacific countries of India, Philippines, Australia, and Thailand are expected to be responsible for 13% of global PSH growth. Power system reliability needs, coupled with coal plant retirements, increasing renewables-based generation, high electricity prices and recently announced government support for over 750 megawatts (MW) of PSH have created a robust project pipeline in Australia. The outlook for PSH is also improving in the MENA region: Morocco, and Israel together are expected to add 650 MW of capacity, while the United Arab Emirates and Egypt have both recently announced plans to develop PSH.

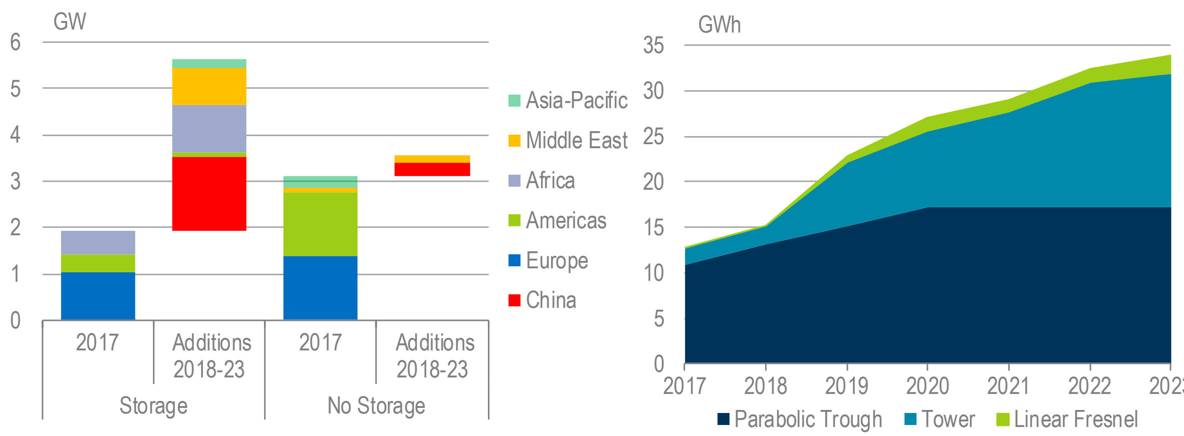
By 2023, electricity generation from PSH rises by one-quarter to reach 146 TWh, although the average operating hours of the PSH fleet are considerably uncertain and the range of capacity factors is wide due to the variability of market conditions (Figure 5.16). In liberalised or partially liberalised markets such as Europe and the United States, generating decisions will be dictated by plant profitability. In Europe, these prospects are based mostly on the difference between peak and off-peak prices, a spread that is becoming increasingly difficult to predict. Consequently, generation from some PSH plants may decline in some markets over the next six years: in Germany, one PSH plant owner recently announced that operating hours in certain plants would be reduced to preserve profitability. In the United States, PSH generation going forward will also depend on its competitiveness with other flexible sources such as natural gas-fired plants.

In China, the operating hours of PSH plants will depend on how grid operators decide to dispatch them in the most cost-effective way to optimise system operations. Historically, PSH plants have been under-utilised because previous tariff regimes failed to incentivise plant operation (Zhang et al., 2015). As a result, capacity factors for the fleet were relatively low (6-8%) from 2010 to 2015. However, in 2016, the fleet average reached 14%, suggesting the potential for higher PSH generation over the next five years, depending on overall power demand, fleet profile and regional grid interconnectedness.

9. Will concentrating solar power (CSP) contribute to global energy storage growth over the forecast period?

In addition to PSH and battery storage, CSP can provide large-scale energy storage, but the way CSP thermal storage characteristics differ from those of PSH and stationary batteries prevents direct comparison. Nonetheless, most CSP plants deployed over the outlook period are expected to include thermal storage, though at a comparatively small scale with only almost 6 GW to be commissioned by 2023. Thermal storage capacity of CSP is projected to reach 34 GWh (Figure 5.17).

Figure 5.17 CSP capacity by technology (left) and CSP thermal storage volume (right)



Of all CSP capacity to be commissioned over 2018-23, 33 projects (representing 85%) are expected to include storage, led by China (1.6 GW), Africa (Morocco and South Africa; 1 GW) and the Middle East (0.8 GW), while only seven projects without storage are anticipated: 365 MW in China and 170 MW in the Middle East. Accordingly, storage volume from CSP thermal storage grows from 13 GWh in 2017 to 34 GWh in 2023.

To take advantage of economies of scale, CSP projects are expected to become larger – over 100 MW on average. The Al Maktoum solar park 700-MW CSP project in the United Arab Emirates is expected to be the largest globally once commissioned in 2023. The preference for smaller projects in the past resulted from Spain leading the market and 50 MW being the maximum size for FIT eligibility. Most additional projects will be towers (20 projects totalling 1.8 GW), followed by 15 parabolic trough projects (1.6 GW) and four using linear Fresnel technology (165 MW). The technology for another 380 MW is still to be determined by a tendering process.

Electricity from CSP is relatively expensive compared with that generated from solar PV and wind. However, recent announcements, including the USD 73/MWh for the United Arab Emirates' 700-MW CSP project, indicate significant cost reduction potential. This energy-only cost comparison does not take into account the ability of CSP to shift the time of generation and to provide ancillary services to power systems. Further cuts to technology costs will depend on the pace of deployment and experiential learning, but its high costs compared with other technologies, especially solar PV, remain a barrier. Access to financing for CSP projects is stifled by a combination of technology risks, country risks, large project size and development costs. Ongoing projects rely on generous FITs (China, Israel) and access to low-cost financing (the Middle East and Africa). However, research and development (R&D), technology learning and mass deployment promise significant cost reduction potential.

While this report projects limited CSP deployment until 2023, IEA long-term scenarios forecast a more pronounced role for CSP, with thermal storage after 2030, especially owing to the flexibility and energy security it can provide to power systems that incorporate high shares of VRE.

10. Is there scope for renewable heat technology costs to fall as they have for solar PV and wind?

Yes, there is scope for costs to fall, in spite of most renewable heat technologies being relatively mature. The costs of renewable heat options vary considerably depending on factors such as technology, application and installation costs. Under some circumstances, they can be very cost-competitive (for example, solar water heating systems in sunny climates), but in other cases renewable heat costs are higher than for conventional fossil fuel technologies, either in terms of capital costs or per unit of energy delivered. Higher costs can be addressed by policy intervention, through carbon pricing and other instruments such as grants or tax credits.

The IEA's Technology Collaboration Programme on Solar Heating and Cooling (SHC) has recently been analysing cost reduction potential for residential solar water heating and solar combi systems. A key finding is that there is potential for reducing costs at every stage of the solar thermal value chain.

Standardisation of components is vital: collectors currently vary greatly in size and there is great diversity in mounting systems. Standardisation could reduce costs along the entire value chain, including in planning, production, distribution and installation. In Europe, where labour costs are high, one of the most promising areas for cost reduction is the installation stage. Overall savings of around 30% compared with a typical solar thermal system are considered possible.

Another cost-reduction opportunity is to use innovative materials, especially polymers that reduce the number of production steps significantly compared with conventional solar thermal collector production. Polymeric connectors also are considerably lighter, which can facilitate installation.

Finally, size also matters. Solar thermal systems for single-family homes tend to be much more expensive per kWh than larger systems (e.g. for apartment blocks). Using case studies in Austria, France and Germany, SHC researchers found that specific thermal energy costs (STECs)[4] for multi-family systems were between 24% and 52% lower than for single-family systems (Table 5.1), bringing the costs below those of a conventional water heating system. Larger systems can also be integrated more easily with other technologies such as heat pumps.

[4] STEC expresses the cost of heat produced by complete solar thermal systems over their lifetime, including the cost of auxiliary heaters when needed. For more details, see IEA-SHC (2017), "Task 54: LCOH for solar thermal applications".

Table 5.1. Solar heat and natural gas heating costs in selected countries

	Austria			Germany			France		
	MFH	SFH	Reduction	MFH	SFH	Reduction	MFH	SFH	Reduction
Estimated STEC of solar heat (US cents/kWh)	6.8	14.1	-52%	7.5	11.8	-36%	11.8	15.7	-24%
Estimated STEC of conventional back-up heating (natural gas, US cents/kWh)	8.2	11.8	-30%	6.6	8.3	-20%	10.5	13.4	-22%

Notes: MFH = multi-family house; SFH = single-family house.

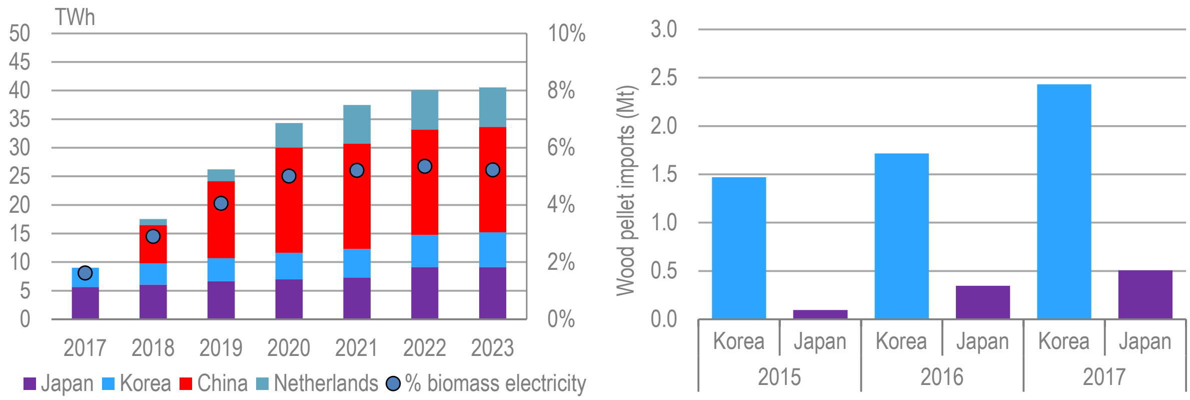
Source: Veynandt (2018), "Cost-competitiveness of multi-family house systems".

Furthermore, deploying large solar thermal installations for district heating can also reduce costs. For example, in Denmark, which has the largest solar thermal district heating installations in the world, the STEC of these systems (including diurnal storage) ranges between USD 36/MWh and USD 46/MWh. In contrast, the STEC for Denmark's small domestic systems is USD 145/MWh to USD 250/MWh (IEA-SHC, 2018).

11. Is there a future for co-firing biomass in the electricity sector?

Policy measures that support co-firing biomass with coal in China, Japan, Korea and the Netherlands ensure the future use of co-firing in the electricity sector. These policies could enable up to 40 TWh of biomass-fuelled electricity generation per year by the end of the forecast period (Figure 5.18) – 5% of global biomass-based electricity generation. Viewpoints differ, however, on whether co-firing should have a role in decarbonising electricity supply, as while it can deliver a number of benefits, it can also be viewed as encouraging the continued use of coal for electricity generation.

Figure 5.18 Co-fired generation in selected countries, 2017-23 (left), and wood pellet imports in Japan and Korea, 2015-17 (right)



Notes: Mt = million tonnes. Forecasting co-firing activity is subject to uncertainties related to support policies, technical factors (e.g. plant outages) and biomass fuel prices. When the economic case for co-firing becomes less attractive, power stations could cease operations or revert to coal-only generation. Co-firing projections assume China's co-firing pilot does not extend beyond the original 84 plants, and that co-firing happens in all 4 plants awarded subsidies in the Netherlands.

Sources: Korea Customs Service (2018), *Import/Export by Country* (database), www.customs.go.kr; Ministry of Finance (2018), *Trade Statistics of Japan* (database), www.customs.go.jp.

Key market conditions and policies that drive co-firing activity

Recent investments in coal capacity together with decarbonisation policies are driving co-firing activity in China, Japan, Korea and the Netherlands. Deployment of new coal capacity is ongoing in the first three, whereas the Netherlands has announced that coal generation will be prohibited from 2030 – even though three high-efficiency coal plants were recently commissioned. Consequently, these countries need to balance ongoing coal-fired electricity generation with decarbonisation pledges made under the COP21 (Conference of Parties) global climate agreement.

Other policy commitments in these countries also facilitate co-firing. The Netherlands must rapidly increase renewables consumption by 2020 to meet its target under the EU Renewable Energy Directive. In Japan, power producers have voluntarily agreed to reduce the amount of CO_2 produced per kWh of electricity by 35% (from the 2013 level) by 2030, while in China the use of agricultural residues for co-firing is a means of avoiding in-field burning and the traditional use of biomass for heating during the winter that results in particulate matter (PM) emissions and air quality deterioration.

As a result, policy support for biomass co-firing is in place in all four countries. In Japan, it is supported by a FIT. Co-firing can also be used by existing coal plants to meet the minimum efficiency standards for thermal power units under the energy conservation law, since biomass fuels are not included in the calculation to determine efficiency, making it easier for less-efficient coal plants to meet minimum efficiency requirements.

In Korea, power generators with installed capacity greater than 500 MW must gradually increase their share of renewable generation to 10% by 2023 under the Renewable Portfolio Standard (RPS). Failure to meet RPS obligations is subject to a maximum penalty of 150% of the average market value of each compliance certificate not obtained for the year in question. Based on average certificate prices in 2016, this equates to around USD 180/MWh. Co-firing is currently eligible for one certificate per MWh and has been used by obligated parties as a key means to meet RPS obligations since 2012.

In the Netherlands, the Stimulation of Sustainable Energy Production (SDE+) scheme awarded eight years of co-firing subsidies at between USD 99/MWh and USD 111/MWh to four coal plants in 2016. One of them already has the infrastructure necessary to co-fire biomass at high levels (i.e. 50%[5] or above) and aims to ramp up co-firing in 2018. The other three have yet to make a final investment decision to proceed with co-firing at lower levels (up to 15% biomass).

China's National Energy Administration (NEA) issued a new co-firing policy in late 2017, whereby a pilot programme will enable existing coal-fired power stations to combust a range of biomass fuels, up to 12%; whatever share of generation is determined to be from biomass will be eligible for policy support. Eighty-four coal plants with a combined capacity of 55 GW plan to participate in the pilot, which may last up to 2020 and, if successful, lead to a longer-term policy.

Within the pilot programme, priority for co-firing will be given to agricultural and forestry wastes in 13 major grain-producing provinces, and to EfW in 36 cities with limited landfill capacity but large sewage and municipal waste production. The new policy obligates grid operators to purchase biomass-based generation from participating plants in their jurisdiction, and engages local governments to ensure pilot projects receive adequate policy support.

[5] All percentage values in this section express co-fired biomass shares in terms of energy.

Future prospects for co-firing in the electricity sector are tied to the use of coal. As such, it seems co-firing could continue in China, Japan and Korea as long as coal is used in the electricity sector. In addition to the four countries mentioned, biomass co-firing activity has taken place in the United States, Chile, Poland, Hungary, the Czech Republic, Slovakia and Estonia, incentivised by a variety of support mechanisms.

Conversely, its use is limited in countries with coal phase-out commitments, such as the 20 nations within the COP23 Powering Past Coal Alliance that are phasing out traditional coal-fired power generation and placing a moratorium on new coal power stations without operational carbon capture and storage. Co-firing subsidies will end by 2024 in the Netherlands since it is a member of this alliance.

Why does co-firing divide opinion?

Co-firing biomass with coal offers a range of benefits: if low shares of biomass are used, only minimal modifications to existing pulverised coal facilities are required to accommodate co-firing. Therefore, using existing coal infrastructure means co-firing can be delivered relatively quickly compared with new-build renewables projects. Using higher shares of biomass does, however, necessitate modifications to the fuel-handling and feed systems, and to burners.

Regardless of co-firing configuration, investment and operational costs are generally lower than for new biomass plants. Investment costs are generally between USD 250/kW and USD 600/kW, with generation costs of USD 40/MWh to USD 120/MWh; costs vary according to biomass share, configuration, and fuel type.

Wider benefits include:

- The provision of dispatchable renewable generation.
- Higher generation efficiency than for smaller-scale dedicated biomass power plants.
- Provision of a foundation for full conversion to biomass use.
- Fuel supply chain development that can support other biomass projects.
- Flexibility to use seasonably produced fuels, which can be challenging for dedicated plants.

The question of whether co-firing decarbonises electricity generation polarises opinion. The direct substitution of a percentage of coal with sustainable biomass in a power station does reduce the CO_2 emissions intensity of electricity generation, and emissions of other air pollutants such as sulphur oxides (SO_X) and nitrogen oxides (NO_X) should also be reduced. However, it is argued that the ongoing use of coal for electricity generation, even with biomass co-firing, is not compatible with the ambitions of the COP21 climate agreement, especially when low-level (<10%) co-firing occurs.

Biomass resource use efficiency is also lower for co-firing in condensing electricity plants than for co-generation or heat-only uses. As a result, only projects employing high-efficiency biomass co-generation will be eligible for state aid in the European Union as of 2020, ruling out policy support for further co-firing in electricity-only plants. Another criticism is that policy support for co-firing potentially blocks investment in other renewable technologies, and that locally available biomass fuel is not sufficient to meet demand in many cases, necessitating imports (Figure 5.18). When biomass is transported over significant distances, governance is needed to ensure fuel sourcing is sustainable and greenhouse gas (GHG) emissions from transport are accurately recorded.

12. Will energy from waste become the key from of bioenergy in Asia?

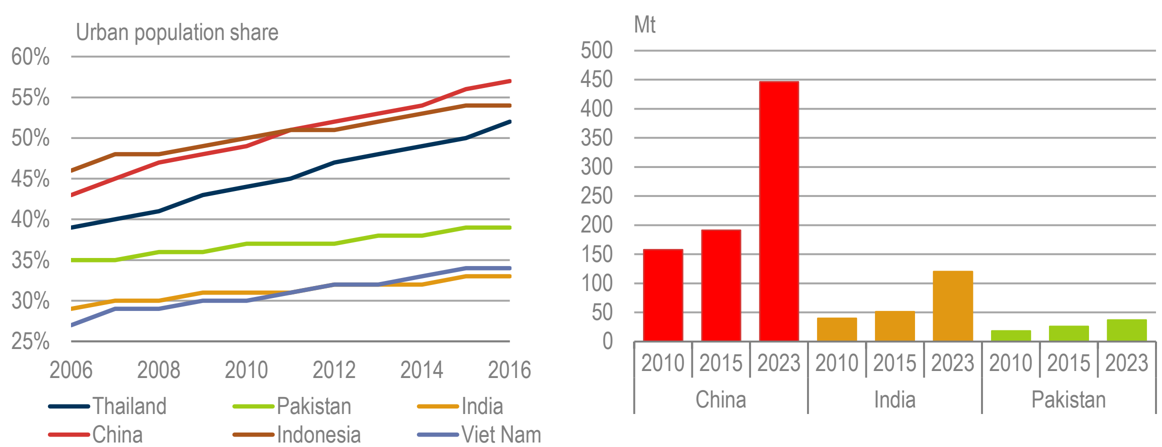
EfW is undoubtedly becoming more important in Asia, as rising municipal solid waste (MSW)[6] production in many countries means cities must rapidly develop new waste management solutions. However, while China is rapidly rolling out EfW technology, its potential is underexploited in other Asian countries. When undertaken in a best-practice manner, EfW facilities can deliver environmental, health and energy benefits, offering a valuable waste management solution.

MSW production is growing in developing and emerging Asian economies

The combination of urbanisation and economic growth in many Asian countries means that solutions are needed to dispose of increasing volumes of MSW. Urban population growth increased 8% in China, 7% in Thailand, 5% in Indonesia and 4% in Viet Nam over 2010-16 (World Bank, 2018). Urbanisation in India and Pakistan is also on the rise, although at a lower rate (Figure 5.19). Considering population growth, this trend resulted in an additional 160 million city-dwellers in these countries over the same period. In terms of economic growth over 2010-16, gross domestic product (GDP) increase in all these countries exceeded the global average.

MSW production per capita has increased as a result of these larger urban populations and the higher living standards afforded by GDP growth. Over 2010-15, annual MSW production in China, Thailand, Viet Nam, India and Pakistan combined grew by an estimated 60 Mt, to over 300 Mt; China accounted for over half of this increase. Combined waste from these countries could more than double during 2015-25, resulting in over 600 Mt of MSW annually by 2023.

Figure 5.19 Urban population shares, 2006-16 (left), and MSW production (right)



Note: Estimated MSW production in 2023 was calculated based on the difference between 2015 data and World Bank projections of MSW production in 2025, prorated to 2023.

Sources: World Bank (2018), "Urban population" (dataset), https://data.worldbank.org; United Nations (2018b), *World Population Prospects 2017* (database), esa.un.org; United Nations (2018a), *Municipal Wastes* (database), http://data.un.org; World Bank (2012), *What a Waste: A Global Review of Solid Waste Management*.

If not correctly managed, MSW impacts human health and the environment in a range of ways. Health hazards result from ground and surface water contamination by leachate, and from air

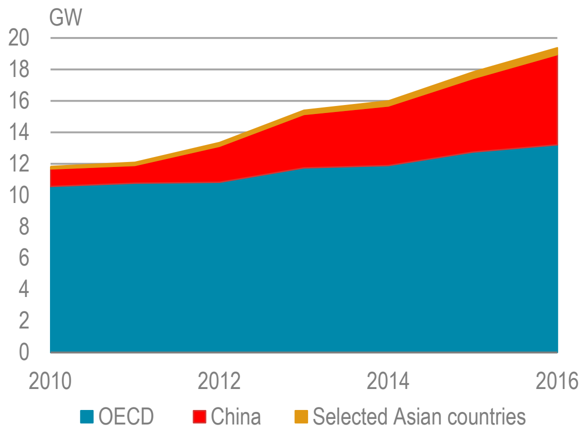
[6] Municipal waste can be defined as waste collected and treated by or for municipalities. It covers waste from households, commerce and trade, office buildings, institutions and small businesses, as well as yard and garden waste, street sweepings and the contents of litter containers.

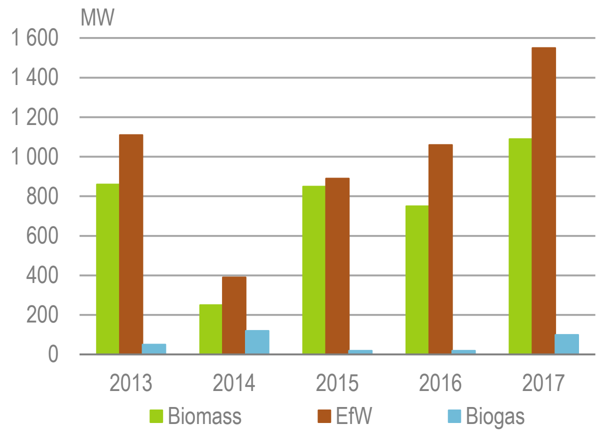
pollution from informal waste burning. Ineffective collection and disposal of waste also attracts vermin and insect infestations that spread disease, and MSW decomposition produces methane, which has a significantly higher global-warming potential than CO_2.[7] For these reasons, the impetus for cities to provide effective waste management is strong.

Status and outlook for EfW deployment in these Asian countries

China has the largest installed EfW capacity globally (7.3 GW), with 339 plants in operation at the end of 2017. EfW has grown by 1 GW per year on average in the past five years, and now represents the largest form of bioenergy capacity, capable of managing just over 100 Mt of solid waste per year (almost 40% of national production). Capacity in China grew at an annual average growth rate of 26% over the past five years, compared with 4% in OECD countries over 2010-16. Consequently, EfW capacity in China is now equivalent to 40% of that installed in all OECD countries combined (Figure 5.20). It has been expanding more slowly in the other five Asian countries mentioned, however, at an average rate of 16% annually.

Figure 5.20 EfW capacity growth, 2010-16 (left), and bioenergy additions in China, 2013-17 (right)





Note: Selected Asian countries refers to India, Indonesia, Pakistan, Thailand and Viet Nam. Biomass refers to fuels from agricultural and forestry sources.

Sources: IEA (2018b), *Renewables Information 2018*, www.iea.org/statistics; IRENA (2018a), "Renewable capacity statistics 2018".

Government targets indicate that EfW capacity will continue to expand in China: under its 13th FYP, 10 GW of the 23-GW bioenergy target for 2020 is allocated to EfW, which will account for more than 50% of MSW treatment nationwide. Within the *Renewables 2018* main case forecast, therefore, EfW capacity in China grows to over 13 GW by 2023, and by 2025 it could manage 260 Mt of MSW. However, there have been incidents of public opposition to EfW on air quality and health grounds, so realising projected growth will require sensitively conducted public consultations and the use of best available technologies.

Several policies are spurring EfW capacity deployment: first, a FIT of RMB 0.65/kWh (USD 95/MWh) has been in place since 2010, and local municipalities also support EfW through waste disposal fees,

[7] Methane's global-warming potential is 28 times that of CO_2 over a 100-year timespan, according to the Intergovernmental Panel on Climate Change (IPCC) (UNFCCC, 2016).

low-cost loans and fiscal support. In addition, the 13th FYP allocates more than USD 40 billion of funding to new facilities. This combination of measures makes EfW development economically attractive.

EfW deployment in India has been slow: just under 300 MW of capacity had been installed at the end of 2017, and the country's largest plant (24 MW) was commissioned in New Delhi just last year. Factors favouring further EfW deployment include the availability of tipping fees, tax incentives and financial de-risking measures. In addition, states have been directed to procure all electricity generated from EfW projects, and national waste management rules encourage waste segregation and require that non-recyclable waste of high calorific value be used for energy. Conversely, low rates of processing and treating collected MSW hinder sector expansion.

Thailand is also in the early stages of EfW deployment. Several projects are in development and capacity could grow to over 200 MW by 2021, and a longer-term target of 550 MW by 2036 is in place under the Alternative Energy Development Plan. A FIT of USD 155/MWh to USD 190/MWh currently supports deployment, but development is being scrutinised by community groups to ensure projects meet the necessary construction and operation standards.

In Indonesia, Viet Nam and Pakistan, EfW deployment is hampered by several key challenges:

- Underdeveloped waste collection services, segregation infrastructure and recycling.
- Welfare considerations for "waste pickers" whose livelihood depends on landfill sites.
- Low waste-disposal fees and the prevalence of "open dumping" practices.
- High financing costs for facilities, given that the track record for EfW plant development is limited.
- Lack of public acceptance.
- Administrative barriers related to permitting.

However, policy support in all three countries is gaining strength. Pakistan introduced an EfW tariff of USD 100/MWh in 2018, and projects are in development in Lahore and Islamabad. Viet Nam has introduced fiscal tax exemptions, a guaranteed power offtake, and a tariff of USD 73/MWh to USD 105/MWh to encourage EfW projects, and the Asian Development Bank has made loan funding available for EfW plants in the Mekong Delta. In Indonesia, a national strategic project has been announced to develop EfW plants in 12 major cities with a purchase tariff of USD 133/MWh.

Is EfW a valid solution to growing MSW production?

Best-practice energy recovery, compared with landfills, can deliver both sanitary and environmental benefits. EfW technology considerably reduces the volume of waste produced, so EfW facilities require far less land area than landfill sites do. In addition, waste disposal sites in many counties do not meet sanitary landfill standards by fully isolating waste from the surrounding environment, and uncontrolled burning often happens when waste collection and disposal are inadequate, which negatively impacts air quality. The use of EfW plants with controlled high-temperature combustion and pollution control technology is a superior solution.

EfW is primarily a waste management rather than energy solution, as it can process a high share of municipal waste but supplies a relatively low share of city energy demand. Nevertheless, it does deliver electricity and, when there is a suitable offtaker, heat at the point of demand. This can help offset rising energy demand from an increasingly urban population with higher standards of living. Also, since waste is domestically sourced, EfW supports energy supply diversification.

However, EfW should only be deployed as part of the wider waste management hierarchy of prevention, preparing for reuse, recycling, (energy) recovery and disposal. This requires that municipal governments undertake integrated waste management planning to maximise the reuse and recycling potential of materials prior to energy recovery. Furthermore, sufficient collection and source-segregation infrastructure is needed so that refuse-derived fuel (RDF) with suitable energy and moisture content can be provided to EfW facilities.

Several other factors are important to ensure best practice and economical EfW development:

- Application of best available pollution control technologies.
- Monitoring to ensure emissions to air and water, as well as noise and odour, remain within regulatory limits.
- Stakeholder consultation with local communities to gain public confidence.
- Waste disposal fees (i.e. charges levied upon waste received at a processing facility), possibly in the form of landfill taxation or gate/tipping fees.

13. How competitive is biofuel production in Brazil and the United States?

The United States ranks number one and Brazil ranks second as the largest producers of fuel ethanol and biodiesel. They accounted for 84% of global ethanol production between them in 2017, and 26% of biodiesel production. In both countries, fuel ethanol and biodiesel are blended with fossil transport fuels, and in Brazil unblended fuel ethanol also competes directly with gasoline at the pump. However, as production costs for biofuels, gasoline and diesel vary by country, the consequent difference in break-even oil price for ethanol and biodiesel, as well as policy measures, affect biofuel competitiveness in both countries.

Which factors affect the economics of biofuel production in Brazil and the United States?

Multiple factors affect biofuel production cost, pricing and profitability. Feedstock cost is a key determiner of biofuel production costs. For fuel ethanol, corn is the principal feedstock in the United States and Brazil mainly uses sugar cane, and both countries primarily use soybeans for biodiesel production. The prices of these agricultural commodities depend on planted area, yields and harvest conditions, as well as markets dynamics, all of which are subject to year-on-year fluctuations. A production facility's technical sophistication and the price of fuels used for process energy also influence production costs.

Biofuel pricing is also determined by other factors: for instance, prices are often adjusted according to prevailing gasoline and diesel prices to maximise profit margin. In Brazil, the price of sugar cane ethanol fluctuates with the harvest cycle, rising during the January-March inter-harvest period.

To assess the profitability of biofuel production, the value of co-products must also be considered. For example, corn-based fuel ethanol manufacturing produces dried distiller's grains (DDGs) while biodiesel production from soybeans results in soybean meal. Both are valuable animal feed products and are therefore important to biofuel production economics. In Brazil, bagasse is produced during sugar cane-crushing and is used as a fuel in sugar mill co-generation plants to satisfy onsite energy demand, and in some cases provides surplus electricity for export. Future production of cellulosic ethanol in Brazil would increase demand for bagasse as a feedstock for advanced biofuel production, consequently raising its value.

How competitive are biofuels with fossil-based transport fuels in both countries?

Most of the biofuel produced in Brazil and the United States is destined for domestic consumption. However, even though biofuel consumption is mandated in both countries, its competitiveness with gasoline and diesel remains important to minimise the cost of policy compliance. In Brazil, over 70% of the gasoline-fuelled vehicle fleet is composed of flex-fuel vehicles, so unblended hydrous ethanol must compete with gasoline at the pump.

To assess the relative competitiveness of biofuels with petroleum products, gasoline and diesel production costs must be compared with those of ethanol and biodiesel. Production costs for gasoline and diesel are lower in the United States than in Brazil, potentially explained by the economies of scale provided by larger and more sophisticated refineries, the use of low-cost natural gas as a process fuel, and optimisation of the refinery slate[8] to produce higher volumes of transport fuels. Brazil is a net importer of both gasoline and diesel, but analysis of biofuel competitiveness with imported petroleum products is outside the scope of this evaluation.

Ethanol production costs are generally slightly higher in Brazil than the United States (Table 5.2); in 2017, this difference was in the order of 6-7%. Fuel distribution costs are similar in both countries, but higher gasoline production costs in Brazil mean that fuel ethanol is more competitive than in the United States. Average biodiesel production costs are also broadly aligned because most production in both countries is based on soybean oil feedstock.

Table 5.2. Ethanol and biodiesel production costs and break-even oil price 2017

	Ethanol production cost (USD/Lge)	Biodiesel production cost (USD/Lde)	Ethanol break-even (USD/bbl)	Biodiesel break-even (USD/bbl)
Brazil	0.54 – 0.62	0.73 – 0.98	50 - 60	81 – 120
United States	0.51 – 0.58	0.76– 0.86	64 - 76	104 - 120

Notes: Lge = litre of gasoline equivalent; Lde = litre of diesel equivalent; bbl = barrel. Biofuel production costs have been adjusted to account for the higher calorific values of gasoline and diesel. In 2017, energy-adjusted production costs for ethanol in Brazil were equal to domestically produced gasoline on average, compared with an ethanol premium of USD 0.15/L in the United States. In Brazil the biodiesel premium was USD 0.26/L above fossil-based diesel production on average, smaller than in the United States, where the premium was USD 0.37/L in 2017. Production costs exclude taxes.

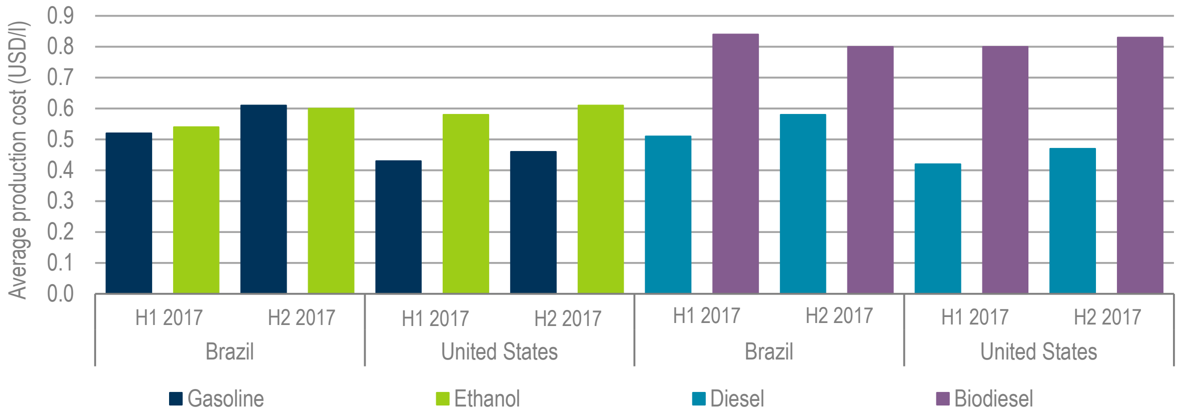
Sources: F.O. Lichts (2018), *F.O. Lichts Interactive Data* (database), www.agra-net.com; ANP (2018), "Producer prices", www.anp.gov.br; US EIA (2018), *Petroleum and Other Liquids* (database), www.eia.gov.

The break-even oil price for biofuel production reveals that, at 2017 crude oil prices of between USD 46/bbl and USD 64/bbl, ethanol production in Brazil was generally competitive with domestic gasoline production, but this was not the case in the United States. The cost of ethanol production in both countries is generally lower than for biodiesel, which was not competitive with fossil diesel in either country because, on a volume basis, soybean oil feedstock costs were almost three times higher than average crude oil prices in 2017.

[8] The product or refinery slate refers to the desired range of products to be produced and their quality.

Increasing crude oil prices in 2017 reduced biofuel cost premiums: the average crude oil price in the first half of 2017 was around USD 51/bbl, and it rose to USD 57/bbl for the second half of the year, raising biofuel competitiveness in Brazil and reducing the biodiesel premium over diesel by 30%. The effect in the United States, however, was minimal (Figure 5.21) because although higher oil prices raised the cost of gasoline and diesel, biofuel production costs also increased slightly. This could be explained by higher fertiliser and process energy costs. In Brazil, ethanol production is decoupled more from fossil fuel prices because bagasse is used for fuel.

Figure 5.21 Biofuel and fossil-based transport fuel production cost comparison, 2017



Notes: H1 = first half of the year (January-June); H2 = second half of the year (July-December). Biofuel production costs have been adjusted to account for the higher calorific values of gasoline and diesel. Production costs exclude tax.

Sources: F.O. Lichts (2018), F.O. Lichts Interactive Data (database), www.agra-net.com; ANP (2018), "Producer prices", www.anp.gov.br; US EIA (2018), *Petroleum and Other Liquids* (database), www.eia.gov.

Rising crude oil prices in the first half of 2018 may have made fuel ethanol production in the United States more competitive. However, corn feedstock prices exhibit close correlation with crude oil prices, potentially raising the break-even price to above the range shown in Table 5.2 and dampening the effect of higher gasoline prices on US ethanol competitiveness. The break-even price for biodiesel in both Brazil and the United States remains higher than crude oil prices.

How does policy support influence the cost of biofuel consumption?

In the United States, policy support strengthens the economic case for biofuel consumption. In 2017 the average cost of domestically produced biodiesel was between USD 0.76/L and USD 0.86/Lde[9] (F.O. Lichts, 2017). However, eligibility for compliance credits under the Renewable Fuel Standard (RFS2), with an average value of USD 0.27/L in 2017, combined with the availability of a blender's tax credit of USD 1/gallon (USD 0.26/L), reduced the refiners' cost of biodiesel blending to below the cost of fossil diesel.

Fuel ethanol is also eligible for RFS2 compliance credits, worth USD 0.18/L on average in 2017, but not a blender's tax credit.[10] Including the value of DDG and the RIN credits, the profitability of US

[9] Based on free-on-board (FOB) prices in the Midwest states.

[10] The biodiesel renewable identification number (RIN) value is based on the D4 biomass-based diesel category. The ethanol value is based on the D6 total renewable fuel RIN category (F.O. Lichts, 2018). The blender's tax credit for biodiesel was in place for production during 2017, but there is not yet any agreement on its availability for 2018.

corn ethanol output was between USD 0.05/L and USD 0.32/L in 2017. For biofuels consumed in California, credits from the Low-Carbon Fuel Standard (LCFS) provide additional income.

In Brazil, introduction of the RenovaBio programme will require fuel distributors to obtain emissions reductions certificates. This is anticipated to provide a financial stimulus for ethanol and biodiesel production, as well as for the development of advanced biofuels.

Fuel taxation levels also influence price competitiveness at the pump, and hence consumer choices. This is most relevant in Brazil, where gasoline and ethanol compete directly for market shares: as of March 2018, state and federal taxation made up 46% of final gasoline costs (Petrobras, 2018). Ethanol currently benefits from preferential federal taxation rates as well as lower state taxation in some cases, and when taxation on both fuels was raised in 2017, that of gasoline increased more. These changes to fuel taxation, combined with higher crude oil prices, resulted in a 25% increase in hydrous ethanol consumption in the second half of the year. Overall, ethanol accounted for 44% of Brazil's gasoline-pool fuel demand in 2017 (UNICA, 2018).

14. Does household use of solid biomass-based heating affect air quality?

Solid biomass combustion can emit various air pollutants that negatively affect human health, and air pollution from biomass combustion in the residential sector has recently come under the spotlight. In the best cases, these emissions can be maintained within acceptable limits, but emissions levels vary significantly according to type of heating system, how the system is operated, and the characteristics of the fuel used.

Which air pollutants are emitted by solid biomass combustion and how do they impact health?

The most relevant pollutants from solid biomass combustion that affect air quality and pose health risks are products from incomplete combustion (PIC), such as volatile organic compounds (VOC) and solid PM (biomass char, soot and tars). Incomplete combustion also emits carbon monoxide (CO).

In addition, solid biomass combustion results in additional gaseous pollutants such as NO_X and SO_X. Waste wood contaminated with heavy metals and organic chlorine compounds can emit even more air pollutants, but for large-scale combustion of such fuels, appropriately designed flue gas cleaning equipment can reduce emissions to acceptable levels. In small-scale heating applications, uncontaminated woody biomass is predominantly used.

When solid biomass combustion contributes to the PM already in the ambient air from other sources, adverse health effects can result. Inhalable PM smaller than 10 micrometres (PM_{10}) is a key indicator of the health impacts of air pollution. There is strong evidence that exposure to PM_{10} and $PM_{2.5}$[11] can cause cardiopulmonary and cardiovascular diseases, and consequently lead to higher rates of mortality (Nussbaumer, 2017). Combustion particles in the ambient air can also act as carriers of toxic and carcinogenic substances, and CO is a toxic gas that can cause death at high concentrations.

Ensuring low air pollutant emissions from residential biomass heating

Air pollutant emissions from residential biomass-based heating vary considerably depending on the type of heating system, how the system is operated, and the characteristics of the fuel used.

[11] Smaller than 2.5 micrometres.

Open fireplaces and simple log stoves generally create high air pollutant emissions and should be discouraged in urban areas for air-quality reasons. Conversely, modern biomass boilers and stoves can comply with stringent emissions limits when operated appropriately, as outlined in Table 5.3, which shows typical organic carbon (OC) fractions of PM from different biomass heating technologies, indicating the potential health impact of emissions.

Table 5.3. Typical emissions factors for various biomass heating devices

Biomass heating device	PM (g/GJ)	%OC
Open fireplace	322 - 1 610	40 - 75%
Simple log stove	140 - 225	50%
Modern log stove	46 - 90	20%
Pellet Stove	3 - 43	10%
Pellet Boiler	3 - 29	5%
Biomass boiler without emissions control	28 - 57	3%
Biomass boiler with emissions control	8 - 15	2%

Note: g/GJ = grammes per gigajoule.

Sources: Koppejan. J and F. de Bree (forthcoming), *Kennisdocument Houtstook in Nederland* [Knowledge Document in the Netherlands]; Vincente, E.D. and C.A. Alves (2018), “An overview of particulate emissions from residential biomass combustion”.

While only biomass combustion technologies are shown above, fossil heating fuels, particularly coal, also result in high air pollutant emissions. For example, coal combustion for residential heating can lead to PM emissions of 20 g/GJ to 430 g/GJ (Butcher and Ellenbecker, 2012)[12] as well as generally higher sulphur dioxide (SO_2) emissions than from biomass fuels. Conversely, PM emissions from natural gas are lower than from biomass fuels.

The type and level of emissions from biomass heating is linked to whether complete or incomplete combustion occurs in the heating system, as reflected in the wide range of typical PM emissions for some biomass heating devices listed in Table 5.3. Complete combustion minimises harmful air pollutants from PIC,[13] but an ideal mixture of combustible gases and combustion air, air-fuel ratio, residence time in the combustion chamber and flame temperature are required to achieve complete combustion.

If the conditions necessary for complete combustion are not met, secondary measures such as catalytic converters and electrostatic precipitators are available to reduce pollutant emissions from wood stoves and biomass boilers. However, secondary measures are not commonly used in residential-scale systems because they can be costly. Furthermore, the effect of secondary measures can be limited by inappropriate combustion conditions, so they only partly replace the need for near-complete combustion.

How the heating system is operated strongly influences air pollutant emissions, especially for manually operated boilers and stoves. For manual systems, the manner of fuel ignition, quantity of fuel introduced to the combustion chamber and level of combustion air supplied must be carefully administered according to best practices to minimise pollutant emissions. Managing these conditions

[12] Values from the German Institute for Ecology and Politics (2016) analysis also fall within this range.

[13] Complete combustion does not eliminate the production of inorganic aerosol emissions in flue gases from ash constituents such as potassium, calcium and chlorine. Precipitation can be used to reduce emissions of inorganic aerosols to an acceptable level.

manually to ensure near-complete combustion is complicated, so actual emissions can significantly exceed those achieved for a given system under test conditions. This highlights the importance of considering real-world operational conditions when developing emissions standards.

More sophisticated automated heating devices can maintain the conditions necessary to achieve near-complete biomass combustion, and therefore generate very low PIC emissions when operated appropriately. For automated systems, design guidelines and best-practice system specifications are preconditions for ideal operation, and these systems have higher investment costs than simpler, manually operated boilers and stoves.

Ensuring the appropriate fuel is used in the combustion device is also of key importance. To maintain low air pollutant emissions factors such as fuel moisture content, size and ash content must be appropriate. The application of biomass fuel standards, e.g. ENplus for wood pellets, and quality standards for combustion systems and emissions measurement, can further minimise the impact of residential biomass-based heating on air quality.

In 2017 the European Commission announced it was pursuing infringement actions against 16 member states for excessive PM_{10} levels. Consequently, air pollutant emission regulations, monitoring and enforcement is likely to become more stringent for residential solid biomass heating systems. Italy, which has the largest residential wood pellet heating market in Europe, recently passed new legislation to classify biomass stoves according to level of pollutant emissions.

Although solid biomass-based heating offers a renewable, lower-carbon alternative to fossil fuel-based systems, to ensure there is no trade-off between decarbonisation and air quality, policy support may increasingly require that biomass heating systems limit air pollutant emissions to acceptable levels.

Minimising air pollution emissions through sophisticated technologies, appropriate fuel selection and best-practice operation is likely to be key to future market prospects for residential biomass heating. This is already evident, as subsidy eligibility for biomass boilers in Germany and the Netherlands is linked to minimum emissions criteria. Such criteria also apply to wider bioenergy applications, for example in France, where biomass co-generation tenders include air quality in the selection criteria.

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6. DATA TABLES

Table 6.1. Total renewable energy consumption, main case

	Renewable energy			
	Mtoe 2017e	Share (%) 2017	Mtoe 2023	Share (%) 2023
World	**918**	**10.4%**	**1 169**	**12.4%**
USA	140	10.2%	165	11.9%
EU-28	179	17.0%	211	20.5%
China	165	8.9%	230	11.6%
Brazil	89	42.1%	104	44.3%
India	58	10.8%	86	12.1%

Table 6.2. World: renewable energy forecast, main case

	Electricity capacity (GW)							Growth (GW)	
	2017	2018	2019	2020	2021	2022	2023	2012-17	2018-23
Hydropower	1 270	1 292	1 319	1 339	1 355	1 376	1 395	210	125
Pumped storage	*153*	*156*	*161*	*167*	*171*	*175*	*179*	*19*	*26*
Bioenergy	121	129	136	142	147	153	158	41	37
Wind	515	566	618	674	730	786	839	295	324
Onshore wind	*497*	*544*	*591*	*642*	*694*	*742*	*787*	*281*	*290*
Offshore wind	*18*	*23*	*27*	*32*	*37*	*44*	*52*	*14*	*34*
Solar PV	398	481	566	658	756	862	972	328	575
Utility	*225*	*274*	*326*	*377*	*431*	*486*	*544*	*205*	*319*
Distributed	*169*	*202*	*235*	*273*	*317*	*366*	*419*	*120*	*250*
Offgrid	*4*	*5*	*6*	*7*	*8*	*9*	*10*	*3*	*6*
CSP	5	6	6	7	8	9	9	3	4
Geothermal	14	14	15	15	16	17	17	3	4
Marine	1	1	1	1	1	1	1	0	0
Total	**2 322**	**2 488**	**2 661**	**2 835**	**3 013**	**3 203**	**3 391**	**881**	**1 069**
	Electricity generation (TWh)							**Growth (TWh)**	
	2017e	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2012-17**	**2018-23**
Hydropower	4 080	4 175	4 274	4 364	4 440	4 505	4 576	566	496
Pumped storage	*120*	*123*	*126*	*131*	*136*	*142*	*146*	*36*	*26*
Bioenergy	531	592	637	676	708	737	764	203	233
Wind	1 145	1 227	1 350	1 477	1 608	1 746	1 882	709	736
Onshore wind	*1 091*	*1 161*	*1 269*	*1 378*	*1 492*	*1 605*	*1 708*	*666*	*618*
Offshore wind	*55*	*66*	*81*	*98*	*116*	*141*	*173*	*43*	*119*
Solar PV	460	589	710	838	974	1 121	1 277	397	816
CSP	13	15	18	21	23	28	31	10	17
Geothermal	85	89	93	97	101	106	111	16	26
Marine	1	1	1	1	1	1	1	0	0
Total	**6 316**	**6 689**	**7 084**	**7 474**	**7 856**	**8 245**	**8 641**	**1 902**	**2 325**
	Biofuel production (billion L)							**Growth (billion L)**	
	2017e	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2012-17**	**2018-23**
Ethanol	104	110	112	114	114	117	119	20	15
Biodiesel	39	39	43	46	44	45	46	14	6
Total	143	149	154	160	159	162	165	34	22
	Heat (Mtoe)							**Growth (Mtoe)**	
	2017e	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2012-17**	**2018-23**
Bioenergy	323	331	339	345	350	356	361	26	39
Geothermal	14	15	16	17	18	19	20	7	6
Solar thermal	33	35	37	40	43	45	48	15	15
Renewable electricity for heat	86	91	97	103	108	114	119	21	33
District heating from renewables	22	22	23	23	23	24	24	5	2
Total	**478**	**495**	**512**	**527**	**542**	**558**	**573**	**74**	**95**

Table 6.3. China: renewable energy forecast, main case

	Electricity capacity (GW)							Growth (GW)	
	2017	2018	2019	2020	2021	2022	2023	2012-17	2018-23
Hydropower	344	349	358	367	373	382	391	111	47
Pumped storage	*29*	*32*	*35*	*39*	*42*	*45*	*47*	*10*	*18*
Bioenergy	15	18	21	23	25	27	29	8	14
Wind	164	183	203	225	246	265	283	117	120
Onshore wind	*162*	*180*	*198*	*219*	*238*	*255*	*271*	*116*	*109*
Offshore wind	*2*	*3*	*5*	*6*	*8*	*10*	*13*	*2*	*11*
Solar PV	131	164	198	236	279	331	386	128	256
Utility	*101*	*120*	*140*	*160*	*181*	*204*	*229*	*99*	*128*
Distributed	*30*	*44*	*58*	*76*	*98*	*126*	*157*	*29*	*128*
Offgrid	*0*	*0*	*0*	*0*	*0*	*0*	*1*	*0*	*0*
CSP	0	0	1	1	1	2	2	0	2
Geothermal	0	0	0	0	0	0	0	-	0
Marine	0	0	0	0	0	0	0	0	0
Total	**653**	**715**	**781**	**852**	**924**	**1 006**	**1 091**	**364**	**438**

	Electricity generation (TWh)							Growth (TWh)	
	2017e	2018	2019	2020	2021	2022	2023	2012-17	2018-23
Hydropower	1 179	1 191	1 207	1 226	1 240	1 259	1 284	491	104
Pumped storage	*33*	*34*	*36*	*40*	*44*	*48*	*52*	*22*	*19*
Bioenergy	79	100	124	142	153	163	174	52	95
Wind	303	338	377	417	463	508	550	233	247
Onshore wind	*300*	*333*	*368*	*405*	*445*	*484*	*516*	*230*	*216*
Offshore wind	*3*	*5*	*9*	*13*	*18*	*24*	*34*	*3*	*31*
Solar PV	132	189	232	279	331	391	460	129	328
CSP	0	0	1	3	4	7	8	0	8
Geothermal	0	0	0	0	0	0	0	0	0
Marine	0	0	0	0	0	0	0	0	0
Total	**1 694**	**1 819**	**1 942**	**2 067**	**2 191**	**2 330**	**2 477**	**905**	**783**

	Biofuel production (billion L)							Growth (billion L)	
	2017e	2018	2019	2020	2021	2022	2023	2012-17	2018-23
Ethanol	3	4	5	5	6	6	7	1	4
Biodiesel	1	1	1	1	2	2	2	1	1
Total	**5**	**5**	**6**	**7**	**7**	**8**	**9**	**2**	**5**

	Heat (Mtoe)							Growth (Mtoe)	
	2017e	2018	2019	2020	2021	2022	2023	2012-17	2018-23
Bioenergy	-	1	2	2	3	4	4	-	4
Geothermal	10	10	11	11	12	12	13	6	3
Solar thermal	24	24	25	26	27	28	29	13	6
Renewable electricity for heat	14	15	17	18	20	21	23	8	8
District heating from renewables	1	1	1	1	2	2	2	0	1
Total	**49**	**52**	**55**	**59**	**63**	**67**	**71**	**27**	**22**

Table 6.4. India: renewable energy data, main case

	Electricity capacity (GW)							Growth (GW)	
	2017	2018	2019	2020	2021	2022	2023	2012-17	2018-23
Hydropower	48	50	52	54	56	57	58	7	9
Pumped storage	*5*	*5*	*5*	*5*	*6*	*6*	*6*	*0*	*2*
Bioenergy	9	10	10	10	11	11	11	6	2
Wind	33	35	40	44	51	58	65	17	33
Onshore wind	*33*	*35*	*40*	*44*	*51*	*58*	*65*	*17*	*33*
Offshore wind	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
Solar PV	19	28	38	47	58	70	82	18	63
Utility	*16*	*24*	*32*	*40*	*48*	*57*	*67*	*16*	*51*
Distributed	*2*	*4*	*5*	*7*	*9*	*11*	*13*	*2*	*11*
Offgrid	*1*	*1*	*1*	*1*	*1*	*1*	*1*	*1*	*1*
CSP	0	0	0	0	0	0	0	0	0
Geothermal	-	-	-	-	-	-	-	-	-
Marine	-	-	-	-	-	-	-	-	-
Total	**110**	**123**	**139**	**156**	**176**	**196**	**217**	**48**	**107**

	Electricity generation (TWh)							Growth (TWh)	
	2017e	2018	2019	2020	2021	2022	2023	2012-17	2018-23
Hydropower	139	144	149	155	160	164	167	-2	28
Pumped storage	3	3	3	3	3	4	4	3	1
Bioenergy	49	50	52	54	56	58	60	31	11
Wind	59	61	65	74	81	93	106	34	47
Onshore wind	*59*	*61*	*65*	*74*	*81*	*93*	*106*	*34*	*47*
Offshore wind	-	-	-	-	-	-	-	-	-
Solar PV	33	55	76	99	123	148	176	32	143
CSP	1	1	1	1	1	1	1	1	0
Geothermal	-	-	-	-	-	-	-	-	-
Marine	-	-	-	-	-	-	-	-	-
Total	**280**	**311**	**344**	**382**	**420**	**464**	**509**	**96**	**229**

	Biofuel production (billion L)							Growth (billion L)	
	2017e	2018	2019	2020	2021	2022	2023	2012-17	2018-23
Ethanol	1	1	1	2	2	2	2	0	2
Biodiesel	0	0	0	0	0	0	0	0	0
Total	1	1	1	2	2	2	3	0	2

	Heat (Mtoe)							Growth (Mtoe)	
	2017e	2018	2019	2020	2021	2022	2023	2012-17	2018-23
Bioenergy	39	39	42	44	46	47	49	3	10
Geothermal	-	-	-	-	0	0	0	-	0
Solar thermal	1	1	1	1	1	1	2	0	1
Renewable electricity for heat	2	2	2	3	3	3	4	1	2
District heating from renewables	-	-	-	-	-	-	-	-	-
Total	**42**	**45**	**48**	**50**	**52**	**54**	**56**	**4**	**14**

Table 6.5. Brazil: renewable energy data, main case

	Electricity capacity (GW)							Growth (GW)	
	2017	2018	2019	2020	2021	2022	2023	2012-17	2018-23
Hydropower	100	103	108	108	108	109	109	18	8
Pumped storage	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
Bioenergy	15	15	15	15	15	16	16	5	2
Wind	12	14	15	16	16	17	19	11	6
Onshore wind	*12*	*14*	*15*	*16*	*16*	*17*	*19*	*11*	*6*
Offshore wind	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
Solar PV	1	2	3	3	4	5	6	1	5
Utility	*1*	*2*	*2*	*2*	*3*	*3*	*3*	*1*	*2*
Distributed	*0*	*0*	*1*	*1*	*2*	*2*	*3*	*0*	*2*
Offgrid	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
CSP	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0
Marine	0	0	0	0	0	0	0	0	0
Total	**128**	**134**	**141**	**142**	**144**	**147**	**149**	**35**	**21**

	Electricity generation (TWh)							Growth (TWh)	
	2017e	2018	2019	2020	2021	2022	2023	2012-17	2018-23
Hydropower	371	369	387	400	406	412	417	-58	47
Pumped storage	0	0	0	0	0	0	0	0	0
Bioenergy	51	55	56	57	58	59	61	19	10
Wind	42	47	53	58	59	61	62	40	20
Onshore wind	*42*	*47*	*53*	*58*	*59*	*61*	*62*	*40*	*20*
Offshore wind	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
Solar PV	1	3	4	5	6	8	9	1	8
CSP	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0
Marine	0	0	0	0	0	0	0	0	0
Total	**465**	**475**	**500**	**520**	**529**	**540**	**549**	**2**	**84**

	Biofuel production (billion L)							Growth (billion L)	
	2017e	2018	2019	2020	2021	2022	2023	2012-17	2018-23
Ethanol	28	32	32	33	33	35	36	6	9
Biodiesel	4	5	5	6	6	6	6	2	2
Total	**32**	**37**	**37**	**39**	**39**	**41**	**43**	**8**	**11**

	Heat (Mtoe)							Growth (Mtoe)	
	2017e	2018	2019	2020	2021	2022	2023	2012-17	2018-23
Bioenergy	38	39	40	40	40	41	41	1	3
Geothermal	-	-	-	-	-	-	-	-	-
Solar thermal	1	1	1	1	1	1	1	0	0
Renewable electricity for heat	8	9	9	9	9	10	10	1	2
District heating from renewables	-	-	-	-	-	-	-	-	-
Total	**47**	**49**	**50**	**50**	**51**	**51**	**52**	**2**	**5**

Table 6.6. USA: renewable energy data, main case

	Electricity capacity (GW)							Growth (GW)	
	2017	2018	2019	2020	2021	2022	2023	2012-17	2018-23
Hydropower	103	103	103	103	103	103	103	2	1
Pumped storage	*22*	*22*	*22*	*22*	*22*	*22*	*22*	*0*	*0*
Bioenergy	14	14	15	15	15	15	15	3	1
Wind	88	97	107	117	123	128	133	43	44
Onshore wind	*88*	*97*	*106*	*117*	*123*	*128*	*131*	*43*	*43*
Offshore wind	*0*	*0*	*0*	*0*	*0*	*0*	*1*	*0*	*1*
Solar PV	52	62	73	85	97	109	122	48	70
Utility	*31*	*37*	*44*	*50*	*56*	*63*	*70*	*30*	*39*
Distributed	*21*	*25*	*29*	*34*	*40*	*45*	*51*	*18*	*31*
Offgrid	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
CSP	2	2	2	2	2	2	2	1	0
Geothermal	4	4	4	4	4	4	4	0	0
Marine	0	0	0	0	0	0	0	0	0
Total	**263**	**282**	**303**	**325**	**343**	**360**	**378**	**96**	**116**

	Electricity generation (TWh)							Growth (TWh)	
	2017e	2018	2019	2020	2021	2022	2023	2012-17	2018-23
Hydropower	302	279	279	279	279	280	280	-19	-22
Pumped storage	*23*	*23*	*23*	*23*	*23*	*23*	*23*	*0*	*-*
Bioenergy	69	71	71	72	73	73	74	6	5
Wind	257	263	287	316	346	363	379	136	122
Onshore wind	*257*	*263*	*287*	*315*	*345*	*362*	*376*	*136*	*119*
Offshore wind	*0*	*0*	*0*	*0*	*0*	*1*	*3*	*0*	*3*
Solar PV	68	83	98	114	131	149	167	63	99
CSP	5	5	5	5	5	5	5	5	0
Geothermal	18	18	18	18	19	19	19	0	1
Marine	0	0	0	0	0	0	0	0	0
Total	**720**	**720**	**760**	**806**	**853**	**889**	**924**	**191**	**204**

	Biofuel production (billion L)							Growth (billion L)	
	2017e	2018	2019	2020	2021	2022	2023	2012-17	2018-23
Ethanol	60	60	60	59	58	58	58	7	-2
Biodiesel	6	6	6	7	7	7	8	2	2
Total	**66**	**67**	**67**	**66**	**66**	**66**	**66**	**9**	**0**

	Heat (Mtoe)							Growth (Mtoe)	
	2017e	2018	2019	2020	2021	2022	2023	2012-17	2018-23
Bioenergy	42	44	44	45	45	46	46	-3	4
Geothermal	0	1	1	1	1	1	2	0	1
Solar thermal	3	3	3	4	4	4	5	1	2
Renewable electricity for heat	11	12	12	13	14	15	15	3	4
District heating from renewables	1	1	1	1	1	1	1	0	0
Total	**57**	**60**	**62**	**63**	**65**	**67**	**68**	**0**	**11**

Table 6.7. EU: renewable energy data, main case

	Electricity capacity (GW)							Growth (GW)	
	2017	2018	2019	2020	2021	2022	2023	2012-17	2018-23
Hydropower	155	156	156	156	156	157	157	7	2
Pumped storage	*44*	*45*	*45*	*45*	*45*	*45*	*46*	*3*	*1*
Bioenergy	41	43	44	45	46	47	48	9	7
Wind	169	180	188	197	209	222	231	75	62
Onshore wind	*153*	*161*	*166*	*173*	*183*	*192*	*198*	*63*	*45*
Offshore wind	*16*	*19*	*22*	*24*	*26*	*30*	*33*	*12*	*17*
Solar PV	107	113	122	132	142	152	159	54	52
Utility	*36*	*38*	*42*	*47*	*52*	*56*	*60*	*22*	*23*
Distributed	*70*	*75*	*80*	*84*	*90*	*95*	*99*	*32*	*29*
Offgrid	*0*	*0*	*0*	*1*	*1*	*1*	*1*	*0*	*0*
CSP	2	2	2	2	2	2	2	1	0
Geothermal	1	1	1	1	1	1	1	0	0
Marine	0	0	0	0	0	0	0	0	0
Total	**475**	**495**	**514**	**534**	**558**	**581**	**599**	**146**	**124**

	Electricity generation (TWh)							Growth (TWh)	
	2017e	2018	2019	2020	2021	2022	2023	2012-17	2018-23
Hydropower	299	358	359	359	360	361	362	- 13	62
Pumped storage	31	32	32	32	32	32	32	3	1
Bioenergy	183	196	205	213	221	225	230	50	47
Wind	362	380	408	430	452	483	514	182	152
Onshore wind	*311*	*321*	*337*	*349*	*361*	*381*	*399*	*143*	*87*
Offshore wind	*51*	*60*	*71*	*82*	*90*	*102*	*116*	*40*	*65*
Solar PV	114	122	131	142	153	165	175	69	61
CSP	6	6	6	6	6	6	6	4	0
Geothermal	7	7	7	7	7	7	7	1	0
Marine	0	0	0	1	1	1	1	0	0
Total	**971**	**1 069**	**1 116**	**1 158**	**1 200**	**1 248**	**1 294**	**292**	**323**

	Biofuel production (billion L)							Growth (billion L)	
	2017e	2018	2019	2020	2021	2022	2023	2012-17	2018-23
Ethanol	5	5	5	6	5	5	5	2	0
Biodiesel	15	13	15	16	14	13	13	4	-2
Total	**20**	**19**	**20**	**22**	**19**	**18**	**18**	**6**	**-2**

	Heat (Mtoe)							Growth (Mtoe)	
	2017e	2018	2019	2020	2021	2022	2023	2012-17	2018-23
Bioenergy	78	80	81	81	82	83	84	12	6
Geothermal	1	1	1	1	1	1	2	0	1
Solar thermal	2	3	3	3	3	4	4	1	2
Renewable electricity for heat	20	22	23	24	25	26	27	6	8
District heating from renewables	15	15	15	15	15	16	16	4	1
Total	**116**	**119**	**122**	**125**	**128**	**131**	**133**	**23**	**18**

Table 6.8. Ethanol production (billion litres) forecast

	Main case							Acc. case
	2017e	2018	2019	2020	2021	2022	2023	2023
World	**104.0**	**110.1**	**111.7**	**113.9**	**114.3**	**116.8**	**119.2**	**144.9**
North America	**61.6**	**62.3**	**62.4**	**61.3**	**60.7**	**60.4**	**60.4**	**67.1**
Canada	1.7	1.9	2.0	2.0	2.0	2.0	2.0	2.6
United States	59.9	60.3	60.4	59.1	58.4	58.1	58.1	63.8
EU28	**5.0**	**5.3**	**5.3**	**5.8**	**5.4**	**5.0**	**4.8**	**5.8**
France	0.8	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Germany	0.9	1.0	0.9	1.0	0.9	0.8	0.8	0.8
Eurasia	**0.3**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**
China	**3.5**	**4.0**	**4.6**	**5.2**	**5.7**	**6.1**	**7.1**	**19.7**
Asia and Pacific	**3.0**	**3.6**	**3.8**	**4.6**	**5.3**	**5.7**	**6.1**	**8.6**
India	0.8	1.2	1.3	1.6	1.9	2.1	2.3	3.5
Thailand	1.5	1.5	1.5	1.7	1.9	2.1	2.2	2.7
Latin America	**30.0**	**34.2**	**34.8**	**35.8**	**36.1**	**38.3**	**39.6**	**42.5**
Argentina	1.1	1.1	1.1	1.2	1.2	1.2	1.3	2.7
Brazil	27.7	31.8	32.1	33.0	33.3	35.5	36.5	38.0
Africa	**0.2**	**0.3**	**0.3**	**0.6**	**0.6**	**0.7**	**0.7**	**0.7**
Rest of World	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**

Note: Production presented in volume; to convert to energy an approximate calorific value of 21 MJ/litre can be used. Acc. = Accelerated.

Table 6.9. Biodiesel production (billion litres) forecast

	Main case							Acc. case
	2017e	2018	2019	2020	2021	2022	2023	2023
World	**39.2**	**38.7**	**42.8**	**46.2**	**44.4**	**44.9**	**45.7**	**60.5**
North America	**6.4**	**6.6**	**6.9**	**7.5**	**7.9**	**8.0**	**8.2**	**9.9**
Canada	0.4	0.4	0.5	0.5	0.6	0.6	0.6	0.6
United States	6.0	6.3	6.4	7.0	7.2	7.4	7.6	9.3
EU28	**15.0**	**13.3**	**14.9**	**15.7**	**13.9**	**13.2**	**13.1**	**15.7**
France	2.6	2.3	2.6	2.6	2.4	2.2	2.1	2.1
Germany	3.5	3.1	3.2	3.5	3.0	2.7	2.7	2.7
Eurasia	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**
China	**1.1**	**1.1**	**1.2**	**1.4**	**1.6**	**1.9**	**2.1**	**3.0**
Asia and Pacific	**7.8**	**7.7**	**9.2**	**10.6**	**11.2**	**11.7**	**11.9**	**18.8**
Malaysia	0.8	0.6	0.6	1.1	1.2	1.2	1.2	2.5
Indonesia	3.4	3.5	4.2	4.5	4.8	5.3	5.8	8.1
Latin America	**8.4**	**9.1**	**9.7**	**10.0**	**9.1**	**9.2**	**9.5**	**12.3**
Argentina	3.2	3.3	3.3	3.2	2.2	2.0	2.0	3.3
Brazil	4.3	4.8	5.3	5.7	5.7	5.9	6.1	7.6
Africa	**0.2**	**0.2**	**0.2**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**
Rest of World	**0.3**	**0.3**	**0.4**	**0.4**	**0.3**	**0.3**	**0.3**	**0.3**

Note: Production presented in volume; to convert to energy an approximate calorific value of 33 MJ/litre can be used. Acc. = Accelerated.

Table 6.10. Total renewable electricity capacity (GW)

	Main case							Acc. case
	2017	2018	2019	2020	2021	2022	2023	2023
World	**2 322**	**2 488**	**2 661**	**2 835**	**3 013**	**3 203**	**3 391**	**3 658**
China	**653**	**715**	**781**	**852**	**924**	**1 006**	**1 091**	**1 166**
Europe	**567**	**593**	**615**	**638**	**665**	**691**	**711**	**754**
Belgium	9	10	10	11	12	13	13	15
Denmark	8	9	9	10	11	11	12	13
France	49	51	54	57	61	65	68	77
Germany	119	126	129	135	142	148	152	166
Italy	56	57	58	59	60	62	63	64
Netherlands	9	11	12	14	16	18	20	23
Poland	10	10	10	10	12	14	15	16
Spain	52	53	55	58	61	63	63	68
Sweden	29	29	30	31	31	32	32	34
Turkey	39	43	45	47	49	51	53	58
United Kingdom	43	47	50	51	52	54	55	56
Asia Pacific	**353**	**388**	**424**	**459**	**498**	**537**	**578**	**649**
Australia	21	26	30	34	36	39	41	46
India	110	123	139	156	176	196	217	253
Indonesia	9	10	10	11	12	12	13	15
Japan	107	113	119	123	127	131	135	146
Korea	16	18	20	24	26	29	32	40
Pakistan	9	10	12	13	14	15	15	17
Philippines	7	8	8	8	9	10	11	12
Thailand	11	12	13	14	14	15	16	18
Vietnam	18	19	20	20	21	22	22	23
North America	**381**	**404**	**430**	**456**	**480**	**504**	**528**	**557**
Canada	99	100	101	102	104	105	107	109
Mexico	20	22	26	29	34	38	43	48
United States	263	282	303	325	343	360	378	400
South America	**217**	**228**	**239**	**246**	**252**	**260**	**267**	**275**
Argentina	13	15	16	18	19	21	22	25
Brazil	128	134	141	142	144	147	149	153
Chile	11	12	13	14	15	15	16	17
Eurasia	**88**	**90**	**93**	**96**	**98**	**100**	**102**	**104**
Russia	53	53	55	56	56	57	57	58
Ukraine	7	8	9	9	10	10	11	12
Sub-Saharan Africa	**37**	**42**	**46**	**50**	**55**	**59**	**64**	**78**
Ethiopia	4	6	7	8	9	11	11	12
Ghana	8	8	9	9	10	11	12	14
Kenya	2	2	2	2	3	3	3	6
Nigeria	2	2	2	3	3	4	5	9
SouthAfric	8	8	9	9	10	11	12	14
Tanzania	1	1	1	1	1	1	1	2
MENA	**27**	**29**	**33**	**37**	**41**	**46**	**50**	**76**
Egypt	4	4	4	5	6	6	7	12
Iran	13	13	13	13	14	14	15	19
Israel	1	2	3	3	4	4	5	5
Morocco	3	3	4	5	5	6	7	11
Saudi Arabia	0	0	0	0	1	1	2	10
United Arab Emirates	0	1	1	2	3	3	4	8

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 6.11. Total renewable electricity generation (TWh), main case

	2017e	2018	2019	2020	2021	2022	2023	CAGR
World	**6 316**	**6 689**	**7 084**	**7 474**	**7 856**	**8 245**	**8 641**	**5.4%**
China	**1 694**	**1 819**	**1 942**	**2 067**	**2 191**	**2 330**	**2 477**	**6.5%**
Europe	**1 260**	**1 372**	**1 432**	**1 485**	**1 542**	**1 596**	**1 648**	**4.6%**
Belgium	16	17	19	22	24	25	26	8.8%
Denmark	22	22	23	25	27	29	31	6.2%
France	91	108	112	116	121	127	134	6.8%
Germany	218	222	233	238	244	254	264	3.2%
Italy	105	119	120	122	123	126	128	3.4%
Netherlands	17	22	26	32	39	44	49	18.8%
Poland	24	22	23	23	24	28	32	4.9%
Spain	88	105	107	113	119	123	126	6.2%
Sweden	93	96	97	100	101	103	104	1.8%
Turkey	87	98	107	115	126	132	137	7.8%
United Kingdom	99	114	126	134	137	144	150	7.2%
Asia Pacific	**839**	**921**	**1 002**	**1 083**	**1 165**	**1 255**	**1 347**	**8.2%**
Australia	41	45	54	60	65	70	73	10.3%
India	280	311	344	382	421	464	509	10.5%
Indonesia	32	34	36	39	42	45	48	7.0%
Japan	173	191	202	210	218	228	237	5.4%
Korea	20	26	31	37	44	49	54	18.2%
Pakistan	42	44	49	53	57	60	62	6.9%
Philippines	22	23	24	25	27	29	31	5.9%
Thailand	20	27	30	32	34	36	37	11.0%
Vietnam	69	72	75	77	78	80	83	3.0%
North America	**1 212**	**1 203**	**1 262**	**1 329**	**1 398**	**1 448**	**1 498**	**3.6%**
Canada	443	430	441	454	467	471	476	1.2%
Mexico	48	54	61	69	78	88	98	12.5%
United States	720	720	760	806	853	889	924	4.2%
South America	**840**	**864**	**907**	**945**	**969**	**996**	**1 022**	**3.3%**
Argentina	42	42	45	49	53	56	59	6.1%
Brazil	465	475	500	520	529	540	549	2.8%
Chile	35	39	43	46	48	50	52	6.9%
Eurasia	**284**	**302**	**311**	**318**	**323**	**328**	**334**	**2.7%**
Russia	186	192	194	197	199	200	201	1.2%
Ukraine	11	13	15	17	18	18	19	10.6%
Sub-Saharan Africa	**140**	**156**	**171**	**182**	**195**	**209**	**225**	**8.3%**
Ethiopia	15	18	24	27	32	37	40	17.4%
Ghana	11	13	14	14	16	18	19	9.9%
Kenya	9	9	11	12	13	15	15	9.1%
Nigeria	5	5	6	7	8	9	10	11.6%
SouthAfric	11	13	14	14	16	18	19	9.9%
Tanzania	3	3	3	3	3	3	3	2.7%
MENA	**49**	**52**	**58**	**65**	**74**	**83**	**91**	**11.0%**
Egypt	16	17	17	18	20	21	22	5.0%
Iran	16	17	17	18	19	20	21	4.1%
Israel	2	2	4	5	6	7	7	27.7%
Morocco	5	6	7	9	11	13	15	22.2%
Saudi Arabia	0	0	0	0	1	2	3	93.4%
United Arab Emirates	1	1	1	2	4	6	7	58.4%

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. Please refer to regional definitions in the glossary. For OECD member countries, 2017 generation data are based on IEA statistics published in *Renewables Information 2018.*

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[1], Czech Republic, Denmark, Estonia, Finland, France, the Former Yugoslav Republic of Macedonia, Germany, Greece, Hungary, Iceland, Montenegro, Ireland, Italy, Latvia, Lithuania, Luxembourg, Malta, Netherlands, Norway, Poland, Portugal, Romania, Serbia, Sloval Republic, Slovenia, Spain, Sweden, Switzerland, Turkey and United Kingdom.

Middle East and North Africa (MENA)

Algeria, Bahrain, Egypt, Iran, Iraq, Israel, Jordan, Kuweit, Lebanon, Libya, Morocco, Oman, Qatar, Saudi Arabia, Syria, Tunisia, United Arab Emirates and Yemen.

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, Siruname, Trinidad and Tobago, Urugay, Bolivarian Republic of Venezuela (Venezuela).

[1] 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.

Sub-Saharan Africa (SSA)

Angola, Benin, Botswana, Cameroon, Congo, Democratic Republic of Congo, Côte d'Ivoire, Eritrea, Ethiopia, Gabon, Ghana, Kenya, Mauritious, 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, Djibuti, Equatorial Guinea, Gambia, Guinea, Guinea-Bissau, Lesotho, Liberia, Madagascar, Malawi, Mauritania, Rwanda, Sao Tome and Principe, Seychelles, Sierra Leone, Somalia, Zwaziland, Uganda.

List of acronyms, abbreviations and units of measure

Acronyms and abbreviations

AC&T	Aggregate technical and commercial losses
Acc.	Accelerated case
AD	Accelerated depreciation
ANP	National Association of Petrol, Natural Gas and Biofuels
APAC	Asia and Pacific
ASEAN	Association of Southeast Asian Nations
ATJ	Alcohol to jet technologies
BEAT	Base Erosion Anti-Abuse Tax
BNDES	Brazilian National Development Bank
BOO	Build Own and Operate
BSRIA	Building Services Research and Information Association
CAAGR	Compound annual average growth rate
CAFE	Corporate Average Fuel Economy
CEC	China Electricity Council
CEL	Clean energy certificate (Mexico)
CEEW	Council on Energy, Environment, and Water
CfD	Contract for Difference (United Kingdom)
CHP	Combined heat and power
CNG	Biomethane as compressed natural gas
CO	carbon monoxide
CORSIA	Carbon Offsetting and Reduction Scheme for International Aviation
CO_2	Carbon dioxide
CPP	Clean Power Plan (United Satetes)
CPQ	Climate Protection Quota (Germany)
CSP	Concentrated solar power
CST	Concentrated solar thermal
DISCOM	Distribution company (India)
EBA	European Biogas Association
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
EPP	Ethiopian Electric Power
ERC	Energy Regulatory Commission
EfW	Energy from waste

ERCOT	Electricity Reliability Council of Texas
EU	European Union
FAME	Fatty Acid Methyl Ester
FAO	Food and Agriculture Organisation of the United Nations
FFV	Flexible fuel vehicles
FIP	Feed-in premiums
FIT	Feed-in tariff
FYP	Five-Year Plan (China)
GBI	Generation-based incentive
GCS	Green Certificate System (China)
GDP	Gross domestic product
GERD	Grand Renaissance Dam
GHG	Greenhouse gas
GSHP	Ground source heat pumps
GST	Goods and service tax
GUVNL	Gujarat Urja Vikas Nigam Limited India (India)
HEFA	Hydroprocessed esters and fatty acids
HFS	Synthetic isoparaffins
HVO	Hydrotreated vegetable oil
IATA	International Air Transport Association
ICAO	International Civil Aviation Organization
ICE	Internal combustion engine
IETD	Industrial Efficiency Technology Database
IFC	International Finance Corporation
IPP	Independent power producers
IRENA	International Renewable Energy Agency
ITC	Investment Tax Credit (United States)
KEA	Korea Energy Agency
KEPCO	Korea Electric Power Corporation
LAM	Latin America
LBNL	Lawrence Berkeley National Lab (United States)
LCFS	Low Carbon Fuel Standard
LCOE	Levelised cost of electricity
LNG	Liquefied natural gas
LRET	Large-Scale Renewable Energy Target
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
NAMA	Nationally Appropriate Mitigation Action (India)
NBMMP	National Biogas and Manure Management Programme
NDRC	National Development and Reform Commission (China)
NEA	National Energy Administration (China)
NES	Nigerian Electricity Supply Industry
NO_X	Nitrogen oxide compounds
NPS	New Policies Scenario (IEA, World Energy Outlook, Scenario)
NREL	National Renewable Energy Laboratory (United States)

NREP	National Renewable Energy Plan
OECD	Organisation for Economic Co-operation and Development
PM	Particulate matter
PPA	Power purchase agreements
PSH	Pumped storage hydropower
PSRP	Power Sector Recovery Program
PTC	Production tax incentives (United States)
PURPA	Public Utility Regulatory Policy
PV	Photovoltaics
RDF	Refused derived fuel
RE	Renewable energy
REC	Renewable energy certificate
RED	Renewable Energy Directive
REIPPPP	Renewable Energy Independent Power Producer Procurement Program (South Africa)
RES	Renewable energy sources
RO	Renewables Obligation
RoW	Rest of the world
RPS	Renewable portfolio standard
RTFO	Renewable Transport Fuel Obligation
RVO	Netherland Enterprise Agency
SAF	Sustainable aviation fuels
SDE	Sustainable Energy Production
SHC	Solar heating and cooling
SHIP	Solar heating in industrial processes
SHS	Solar Home Systems
SO_X	Sulfur oxide
SRISTI	Solar Transfiguration of India Scheme
SSA	Sub-Saharan Africa
STEC	Specific Thermal Energy Costs
TCP	IEA Technology Collaboration Programme
TJEP	Brazil National Development Bank Long Term Interest Rate
TWC	Three-way catalyst
UCO	Used cooking oil
UDAY	Ujwal DISCOM Assurance Yojana (India)
UHV	Ultra-high voltage
UHVDC	Ultra-high voltage direct current
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

AUD	Australian dollar
BRL	Brazilian real
CAD	Canadian dollar
EUR	euro
JPY	Japanese yen
RMB	Chinese yuan
THB	Thai baht
USD	United States dollar

Units of measure

bbl	barrel (of oil)
EJ	exajoule
gCO_2/km	grams of CO_2 per kilometre
gCO_2/kWh	grams of CO_2 per kilowatt hour
GJ	gigajoule
GW	gigawatt
GWh	gigawatt hour
GWth	gigawatt thermal
kb/d	thousand barrels per day
km	kilometre
kW	kilowatt
kWh	kilowatt hour
kW_{th}	kilowatt thermal
L	litre
MBtu	million British thermal units
mb/d	million barrels per day
MJ	megajoule
Mt	million tonnes
Mtoe	million tonnes of oil equivalent
MW	megawatt
MWh	megawatt hour
MW_{th}	megawatt thermal
m^2	square metre
PJ	petajoule
t	tonne
tCO_{2e}	tonne of carbon dioxide equivalent
TJ	terajoule
TWh	terawatt hours
W	watt

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RENEWABLES 2018

Analysis and Forecasts to 2023

The electricity sector remains the brightest spot for renewables with the exponential growth of solar photovoltaics and wind in recent years, and building on the significant contribution of hydropower generation. But, electricity accounts for only a fifth of global energy consumption, and the role of renewables in the transportation and heating sectors remains critical to the energy transition.

This is why *Renewables 2018*, the annual IEA market analysis and forecast on renewable energy, takes an in-depth look at bioenergy, the largest source of renewable energy globally. Often overlooked, the contribution of sustainable bioenergy represents a "blind spot" in the global debate about renewables. Bioenergy makes a significant contribution across the energy system, particularly in the heat and transport sectors.

In addition to looking at renewable energy across the entire energy system, *Renewables 2018* provides a detailed market analysis and overview of renewables in the electricity, heat and transport sectors as well as forecasts for the period between 2018 and 2023. The report also highlights policy and market improvements that can unlock further growth of renewable energy in electricity and transport biofuels, as well as underlines the untapped potential of sustainable bioenergy and other renewable sources in greening the industry and transport sectors. For the first time, *Renewables 2018* also includes a chapter dedicated to answering some of the key questions raised by the latest developments in renewable energy markets.

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