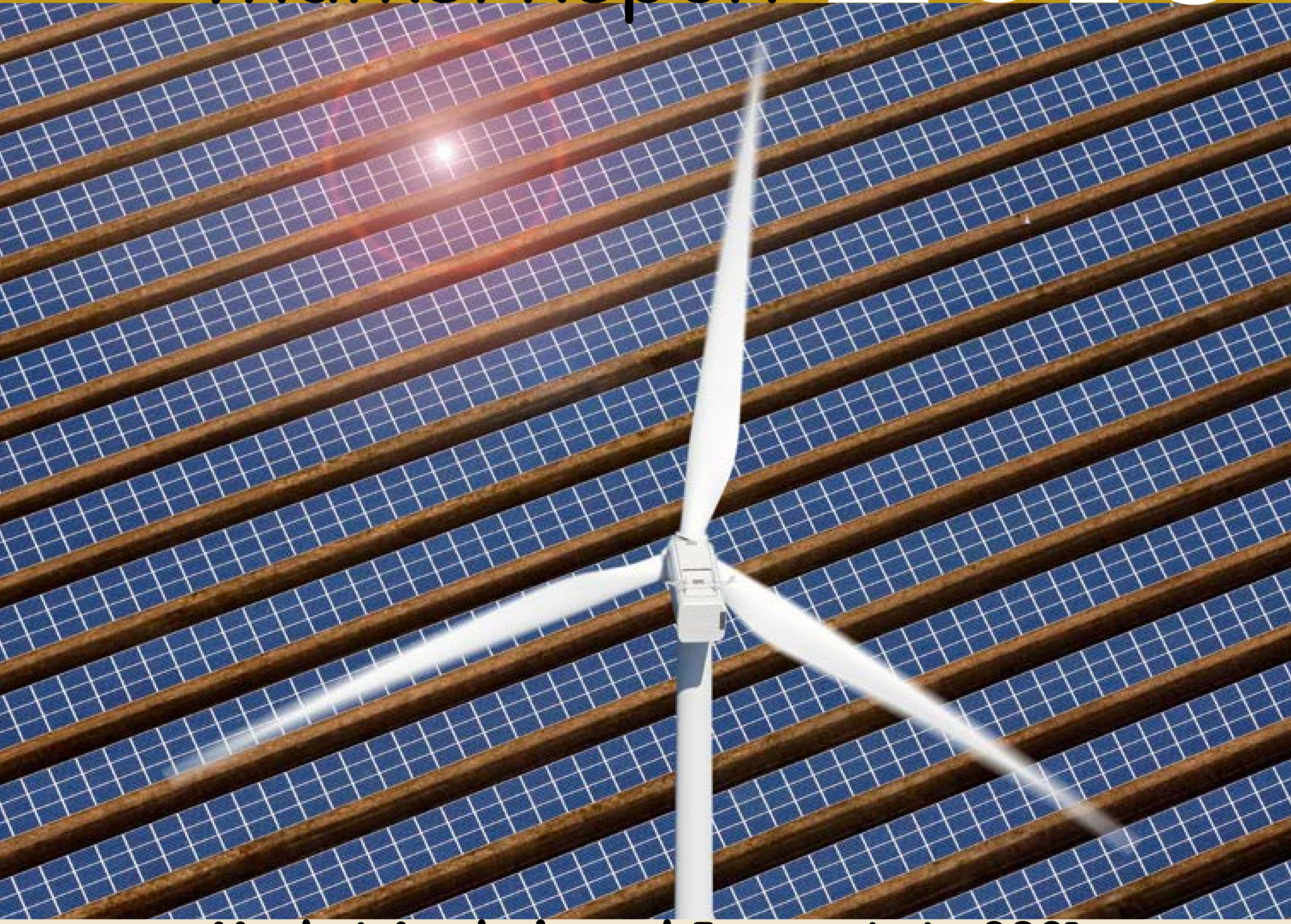
RENEWABLE ENERGY

Medium-Term Market Report 2016



Market Analysis and Forecasts to 2021

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RENEWABLE ENERGY
Medium-Term Market Report 2016

Explore the data behind *MTRMR 2016*

The IEA is expanding the availability of data used to create the Medium-Term Renewable Energy Market Report 2016 publication. Please visit the restricted area of the MTRMR website, www.iea.org/publications/mtrmr/. There you will find country data information including data tables available for download. The website is evolving and will be continuously updated. Your username is "IEA_MTRMRuser" and password "IEA_2016MTREmarkets".

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FOREWORD

One year ago, immediately after starting my new role as the Executive Director of the International Energy Agency (IEA), I presented a new vision for the Agency founded on three pillars: opening the doors of the IEA to emerging economies, strengthening and broadening our commitment to energy security, and bolstering the role of the IEA as an international hub for clean energy technology and energy efficiency. We made important steps supporting all three pillars and our work on renewable energy is at the heart of all three of them.

Renewable energy, together with energy efficiency, is essential to delivering the low-carbon energy future that the international community agreed upon at the United Nations' 21st Conference of the Parties (COP21) last year. Despite low energy prices, 2015 was a year full of records for renewables. For example, cumulative installed renewable power capacity now exceeds that of coal. Deployment is driven by supportive policies that aim not just at decarbonisation, but also – and sometimes even more importantly – at improving energy security and reducing harmful local air pollution. Recent cost reductions for onshore wind and solar PV are impressive and were unthinkable just five years ago. This cost reduction trend, which is expected to continue, will be a key factor in driving renewable deployment. Growth is anticipated to be increasingly concentrated in emerging and developing economies, with Asia taking the centre stage. In the next five years, the People's Republic of China and India alone will account for almost half of global renewable capacity additions.

But much more remains to be done. Even though the forecast for renewable electricity in the IEA *Medium-Term Renewable Energy Market Report* (*MTRMR) 2016* is in line with the commitments submitted within the Intended Nationally Determined Contributions (INDCs) ahead of COP21, this trajectory still falls short of the levels needed to meet more ambitious climate change objectives. This does not mean that these objectives cannot be reached. The *MTRMR 2016* presents examples of strengthened policy support and favourable market conditions in key countries that can help to accelerate growth in the next five years. In this context, addressing system integration of variable renewables will play a central role in tomorrow's energy systems and is a key area of focus at the IEA.

Of course electricity alone does not provide the whole picture. Progress in renewable penetration in the heat and transport sectors remains slow, and significantly stronger policy efforts in both sectors will be needed. This edition of *MTRMR* offers an extended analysis of renewable heat, highlighting policy and market options to accelerate deployment.

The analysis from the *MTRMR 2016*, based on robust data and with close co-operation and insights from policy-makers and energy industry worldwide, tracks progress and identifies future trends in renewable energy technology deployment. It is my hope that, alongside findings from the wider range of IEA medium-term market reports, it will present a clear picture of developments in the global energy system and provide possible pathways to enable policy makers and other stakeholders to accelerate our advance towards a more secure, sustainable energy future for all.

Dr. Fatih Birol
Executive Director
International Energy Agency

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RIAB members

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Questions or comments?

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2015 – A year of records for renewable electricity

In 2015, annual renewable electricity capacity growth reached an all-time record at 153 gigawatts (GW), thanks to record additions in both onshore wind (63 GW) and solar photovoltaics (PV) (49 GW). This is equivalent to more than the total cumulative installed power capacity of a country like Canada. For the first time, renewables accounted for more than half of net annual additions to power capacity and overtook coal in terms of cumulative installed capacity in the world.

Record deployment was accompanied by continued sharp generation cost reductions, with announced record-low long-term remuneration prices ranging from USD 30/megawatt hours (MWh) to 50/MWh for both onshore wind and solar (PV) plants. These projects are expected to become operational over the medium term in markets as diverse as North America, Latin America, Middle East, and North Africa. In addition, recent tender results in Europe for large-scale offshore wind projects indicate possible 40% to 50% cost reductions for new plants by 2021. While these contract prices should not be compared directly to average generation costs, and final project delivery costs may ultimately differ at the time of commissioning, still they signal a clear acceleration in cost reductions, increasing the affordability and improving the attractiveness of renewables among policy-makers and investors.

The Medium-Term Renewables Market Report (*MTRMR)* expects onshore wind generation costs to decrease by a further 15% on average by 2021, while utility-scale solar PV costs are anticipated to decline by another quarter. These trends are underpinned by a combination of sustained policy support, technology progress and expansion into newer markets with better renewable resources. In addition, improved financing conditions play a particularly important role, driven by the expanding use of long-term power purchase agreements (PPAs) awarded through price competitive public or private tenders, including government-backed auction systems.

Policy improvements drive more optimistic outlook for renewable power

Global renewable electricity capacity is expected to grow by 42% (or 825 GW) by 2021. Overall, this forecast is much more (13%) optimistic than *MTRMR 2015*. Most of this revision is due to policy changes and improved market prospects in four key countries. The United States (US) alone represents close to half of the forecast revision thanks to the medium-term extension of federal tax credits, which are set to boost solar PV and onshore wind expansion. The People’s Republic of China’s (hereafter “China”) renewable electricity outlook is also more optimistic with higher (indicative) targets under its 13th five-year economic plan, backed by supportive policies. In India an improved policy environment, competitive tenders and decreasing generation costs are major drivers for the more optimistic solar PV outlook. The recent power reform and auction system in Mexico has also increased expectations for medium-term growth.

Asia is the engine of renewable power capacity growth

China remains the undisputable global leader of renewable energy expansion, representing close to 40% of growth. China’s air pollution concerns and a favorable policy environment are driving the growth. In 2021, more than one-third of global cumulative solar PV and onshore wind capacity will be located in China. Nonetheless, grid integration will remain an important challenge over the medium term, despite policy improvements and anticipated power sector reforms. Moreover, a new challenge of electricity overcapacity may emerge over the medium term given that China still has a substantial number of coal, nuclear and renewable plants under development at the same time as a slow-down in electricity demand growth driven by several factors including energy efficiency improvements.

India's solar PV capacity is forecast to grow eight-fold supported by ambitious government targets and competitive auctions, where contract prices have already declined by a factor of two since 2014. In Southeast Asia, growing electricity demand, increasing fossil fuel imports and air pollution concerns remain important drivers for renewable targets and policies, which are expected to bring increased diversification in the energy mix.

Renewable capacity growth will be faster in the United States than in the European Union (EU). The medium-term extension of federal tax incentives supported by state-level Renewable Portfolio Standard (RPS) policies has improved the economic attractiveness of onshore wind and solar PV, even in the context of current low natural gas prices. With this policy improvement, the United States is set to become the second largest market globally in terms of renewable capacity additions over the forecast period. Weak electricity demand growth, pending legislation on renewables, market design and governance of 2030 targets, as well as persistent policy uncertainty in a number of major countries are the main reasons for a slower expansion of renewable electricity in the European Union compared to the past.

Solar PV and onshore wind lead capacity growth while hydropower additions slow

Solar PV and onshore wind together represent 75% of global renewable electricity capacity growth over the medium-term. Solar PV leads providing almost 40% of global additions while onshore wind is the largest source of new renewable electricity generation. Hydropower growth slows because fewer large-scale conventional projects are expected to be commissioned in China and in Brazil while some projects are delayed in various developing countries. Other renewable technologies are expected to grow at a slower rate but still scale up significantly. Among them, bioenergy is the most significant, with prominent applications including coal-to-biomass conversions particularly in Europe, and the deployment of waste to energy and biogas projects in emerging Asia, particularly in China. Offshore wind capacity is forecast to triple over the forecast period led by deployment in Europe but with China's capacity also scaling-up fast. These developments are complemented by modest growth in concentrated solar thermal (China and Morocco), geothermal (Indonesia and Turkey) and ocean (France and Korea) technologies.

Renewables to provide for the majority of new global electricity demand but strong regional differences are evident

The share of renewables in overall electricity generation will rise from over 23% in 2015 to almost 28% in 2021. Global electricity demand growth is likely to be slower compared to the last five-year period, due to energy efficiency improvements and less-energy intensive economic output. On average, world renewables output is expected to provide over 60% of total electricity generation growth during the forecast period, but strong regional differences are evident. In most developed economies, incremental renewable generation over the medium term is higher than electricity demand growth (e.g. European Union, United States), thus accelerating the de-carbonisation of the power sector. In many emerging markets such as those in China, India and the Association of Southeast Asian Nations (ASEAN) where power demand is expected to continue to grow significantly, renewables are anticipated to meet only a portion of new generation growth.

Biofuels and low oil prices: A complex interplay

The share of biofuels in transport fuel demand is expected to increase only marginally from 3% in 2015 to 4% by 2021, with growth slowing compared to the 2009 to 2015 period. Blending mandates have partly shielded biofuels from the low oil price environment and the strengthening of these in key markets, supporting production growth of 19% over the medium term. However, lower oil prices have resulted in a more challenging investment climate for both conventional and advanced biofuels, heightening the importance of suitable governance measures to ensure compliance with mandated consumption and limiting opportunities for discretionary blending above mandated volumes given less favourable blending economics. Sound regulatory frameworks that can assure the sustainability of biofuels remain key components of appropriate policy support that will be necessary to ensure longer-term market growth.

Asia is poised to head biofuels market expansion over the medium term. While the United States and Brazil will comfortably remain the largest biofuel producers in 2021, Asian markets are forecast to account for over a third of the 2015-21 global biofuels production increase. Driven by security of supply considerations, enhanced policy support for domestically produced biofuels is boosting ethanol production in India and Thailand while biodiesel growth is concentrated in Indonesia and Malaysia. With regard to advanced biofuels, higher output from existing plants and a pipeline of new projects should see higher production. However, significant growth in the industry will require more widespread policy support and is more likely following the medium-term.

Scaling up renewables in the heat sector remains a challenge

Renewable heat deployment is expected to grow slowly over the medium term. Heat accounts for more than half of global final energy consumption and is still primarily supplied by fossil fuels. Modern renewable heat (excluding the traditional use of biomass) currently provides just under 9% of heat demand globally including renewable electricity for heat. The European Union is the biggest producer of renewable heat followed by North America. Of the emerging economies, Brazil stands out in meeting almost 40% of its heating needs (which are primarily in industry) from renewables. Renewable heat use is expected to grow by 21% over the forecast period. This expansion will be dominated by modern bioenergy followed by solar thermal and geothermal, as well as the increasing use of renewable electricity for heat. The growth is likely to come primarily from China, the European Union, North America and India. However, as total global heat demand is expected to grow, the contribution of renewables to heat consumption will rise to over 10% by 2021.

Renewable heat markets face multiple economic and non-economic barriers that need targeted policy support, particularly in a low fossil fuel price environment. Fewer countries have established renewable policies in the heat sector than in the electricity sector, although a variety of instruments are in place across diverse markets, often with a particular focus on the buildings sector and linked to energy efficiency policies. A combination of high investment costs and reduced operational cost savings owing to lower fossil heating fuel prices makes the economic case for investing in renewable heating solutions more challenging especially in the market segment where renewable heat options compete directly with oil boilers such as in Germany and the United Kingdom.

More renewables deployment is required to reach long-term climate goals and reduce harmful air pollution

The MTRMR main case **forecast results show that renewable power growth is currently in line with the INDC electricity targets to 2030.** However, only onshore wind and solar PV deployment are on track with long term 2°C pathways. Meeting the objective of the COP21 global climate agreement to hold the increase in global average temperature to well below 2°C, will require stronger decarbonisation rates and accelerated penetration of renewables in all three sectors: power, transport and heat.

For the electricity sector, *MTRMR* identifies a set of additional policy initiatives in a number of key markets (including China, United States, India, the European Union and Brazil) which could be implemented in a short period of time with significant impacts over the forecast period. Under this *accelerated case* projection, global renewable capacity growth could be 29% higher than in *the main case forecast.* These initiatives would put the global power system on a firmer path towards ambitious climate targets while also improving air quality in key emerging markets (China, India and ASEAN). Achieving this *accelerated case* would require policy makers to address three important challenges to deployment:

- Addressing infrastructure challenges and market design issues to improve grid integration of renewables.
- Implementing stable and sustainable policy frameworks that give greater revenue certainty to capital-intensive renewables and reducing policy uncertainties
- Developing policy mechanisms that reduce cost of financing and lower off-taker risks especially in developing countries and emerging economies.

ANALYTICAL FRAMEWORK

This fifth edition of the *Medium-Term Renewable Energy Market Report* (*MTRMR*) forecasts renewable energy developments within the electricity, heat and transport sectors. Renewable electricity focuses on eight technologies – hydropower, bioenergy for power, onshore wind, offshore wind, solar photovoltaic (PV), solar thermal electricity (STE) from concentrated solar power (CSP) plants, geothermal and ocean power. The renewable transport section provides production forecasts for transport biofuels, including ethanol, biodiesel and advanced biofuels. Final energy use of renewable sources for heat focuses on modern bioenergy (excluding traditional biomass), geothermal and solar thermal technologies.

Renewable energy data present unique challenges

As a relatively young and rapidly evolving market, monitoring renewable energy presents a number of statistical challenges. The size and dispersion of some renewable assets create measurement problems. Small-scale and off-grid applications, such as in solar PV and bioenergy, are difficult to count and can often be under-estimated in government reporting. Identifying the renewable portion from multi-fuel applications, such as in the co-firing of biomass with fossil fuels or municipal waste generation, also remains problematic. Moreover, the increased geographic spread of renewable deployment, particularly within areas outside the Organisation for Economic Co-operation and Development (OECD), creates the challenge of tracking developments in less transparent markets (please see the Glossary of Definitions, Terms and Abbreviations at the end of the book for definitions of how geographic regions are defined).

This report aims to provide a complete view of renewable energy trends over time, both historically (1990-2015) and over the forecast period (2016-21). Official International Energy Agency (IEA) statistics provide the basis for much of the historical data though data coverage is limited in some cases, particularly for 2015 data. Therefore, this report's historical data are determined by consulting multiple sources, including official IEA statistics, work by IEA Technology Collaboration Programmes (IEA TCPs), reporting by industry associations and consultancies, and direct contact with governments and industry. These sources are indicated in the relevant sections of the publication. As such, historical data points, including 2015, may reflect estimates that are subject to revision. Except where noted, prices and costs are expressed in real, 2015 United States dollars (USD).

In this report, hydropower generation data include output from pumped storage plants due to the difficulty in separating the capacity and generation for mixed plants (plants that generate electricity from both natural water inflows and pumping). Electricity output from pumped storage is not considered primary power generation in IEA Energy Balances statistics[1] because the inputs of electricity used to pump the water have already been accounted for under the primary energy source (e.g. coal, wind, solar PV). As such, electricity output from pumped storage is typically excluded from power generation data and treated separately in other analysis. However, because this report forecasts hydropower generation from capacity that cannot always be separated into such discrete parts as in generation, all electricity from pumped storage plants is included. No such attempt to account for only the renewable portion of the pumped generation is made in this report.

[1] See www.iea.org/statistics/topics/energybalances/.

Analysis of heat demand from modern biomass (traditional use of biomass is excluded from the analysis), solar thermal and geothermal heat sources are made within the context of both direct use for heat and commercial heat. While renewables for transport and final energy use of renewable sources for heat could include use of renewable electricity, this report does not attempt to characterise these flows. To maintain the focus on renewable energy markets, where discussing market developments for bioenergy and conventional transport biofuels, no wider assessment of sustainability considerations or related benefits e.g. rural development, for these is included.

Country-level approach underpins the renewable electricity analysis

Given the local nature of renewable development, the approach begins with bottom up country-level analysis of each renewable electricity technology in major markets. Forecasts stem from both quantitative and qualitative analysis of the characteristics and emerging trends in each market. For key markets, country-level examinations start with an assessment of the prevailing renewable project pipeline, which is established using various country-level sources as well as the renewable energy projects database of Bloomberg New Energy Finance (2016). This pipeline is analysed in the context of a country's power demand outlook, power generation situation, grid and system integration issues, current policy environment and the economic attractiveness of renewable deployment.

For some countries, e.g. emerging markets, power demand growth acts as a driver for renewable generation; for others, e.g. more mature markets, demand growth (or lack thereof) can act as a neutral variable or even a constraint on development. Therefore renewable power forecasts are made within the context of the entire power sector. Total power demand and generation forecasts for major markets are based on expectations for real gross domestic product (GDP) and are continuously updated when new historical data is available. Assumptions for GDP growth stem from the International Monetary Fund (IMF) *World Economic Outlook*, released in April 2016. This exercise is done in close co-ordination with other IEA medium-term reports, in particular the *Medium Term Gas Market Report* (IEA, 2016a). From this analysis, an assessment for major markets is made as to whether the power grid can absorb the forecasted generation mix and variability.

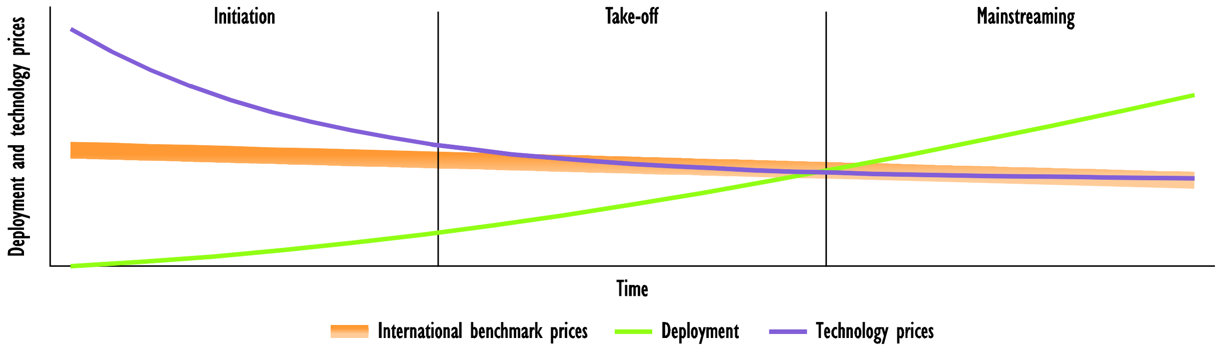
An evaluation of the prevailing policy framework, including announced policies as of August 2016, is a key determinant of the main case forecast. Both the overall enabling environment and the design and implementation of renewable policies are important. The enabling environment includes cross-cutting enablers that can support, or hinder, the successful implementation of policies and the creation of an attractive investment climate, based on five categories (described in more detail in IEA, 2015):

- regulatory and institutional factors
- financial and economic factors
- technical, infrastructure and innovation factors
- social factors
- environmental factors.

Moreover, countries go through different phases of renewable development as deployment grows, and as costs and prices reduce and converge with international norms: *i*) inception, *ii*) take-off and *iii*) mainstreaming (IEA, 2011). The policy priorities between the phases differ: initially, a very secure investment climate is needed to encourage early investors, and an appropriate regulatory framework must be put in place; once deployment takes off, the emphasis shifts to encouraging cost reduction and to managing support costs; in the mainstreaming phase, physical and market integration become the key challenges (Figure 5.1). The position of a given market within this journey and the effectiveness of its policy design and implementation in meeting associated priorities significantly impact the trajectory and sustainability of renewable deployment going forward.

Aside from policy, the *MTRMR 2016* looks at economic attractiveness and power system integration as deployment factors. Attractiveness assessments stem from few variables, including levelised costs of electricity (LCOE), policy incentives, economic resource potentials, macroeconomic developments and the market design of the power system. For many countries the potential exists for policy improvements or non-economic barrier changes over the medium term.

Figure AF.1 The renewable policy journey and changing policy priorities



Initiation phase	Take-off phase	Mainstreaming phase
• The first examples of the technology deployment under commercial terms • **Secure support needed to encourage early investors.** • Local supply chain absent. • Define regulatory framework e.g. permitting procedures may be unclear or lengthy.	• The market starts to grow rapidly. • **Policy priority is to encourage costs to converge with international benchmarks.** • Manage total support costs remain within the expected envelope. • Refine regulatory procedures.	• The annual market has reached a significant scale. • The supply chain is well established. • Generation prices are consistent with international norms and approach fossil-based alternatives. • **Technical and market integration becomes key issues.**

Source: IEA (2015), *Enabling Renewable Energy and Energy Efficiency Technologies: Opportunities in Eastern Europe, Caucasus, Central Asia, Southern and Eastern Mediterranean*, www.iea.org/publications/insights/insightpublications/EnablingRenewableEnergyandEnergyEfficiencyTechnologies.pdf.

Based on IEA analysis for each of the key regions and markets, *main case* forecasts are made for renewable electricity capacity by source through 2021. Generation forecasts are then derived using country- and technology-specific capacity factors, while recognising that resource quality, the timing of new additions, curtailment issues and weather may cause actual performance to differ from assumptions. The resulting country-level capacity and generation forecasts can be found in the online data appendix of the report.

This report includes *accelerated case* projections for renewable capacity to illustrate how certain market and policy enhancements could impact renewable deployment. The aim of the accelerated case is to show how addressing some of the challenges outlined in the main case forecast could result in higher renewable capacity growth over the medium term. A number of country-specific developments, as described within each regional outlook, would need to occur to achieve this result. Given uncertainties over such enhancements occurring in concert, the accelerated case is represented by a range and is indicative of the potential upside for annual renewable deployment over the medium term.

Outlooks for technology and investment guide the global picture

Key market assessments under the main case are judged against developments in renewable technologies and investment. The technology chapter features three sections of analysis. First, it describes system properties of different renewable technologies, industry and manufacturing developments, and recent technology cost developments, including discussion of LCOEs. The primary assumptions used to display the ranges for the main LCOE graphs are listed in the table at the end of this "Analytical Framework" chapter. Further discussion on the advantages and disadvantages of LCOEs regarding larger competitiveness assessments is featured in the "Renewable electricity: Technology forecast" chapter. Second, the section characterises recent market developments by technology. Third, the chapter provides an outlook for market development through 2021. It consolidates, by technology, the country-level forecasts; identifies the key markets; and addresses potential deployment barriers that lie ahead.

The investment analysis reports on recent developments in renewable power investment and forecasts investment needs over the medium term. All investment data presented, unless otherwise noted, are derived from IEA analysis on renewable electricity capacity additions and unit investment costs, historical and forecasted. Investment is defined as overnight capital expenditures on new renewable power plants or the replacement of old plants. When a renewable technology comes to the end of its *technical* lifetime, for the purpose of this report, it is assumed that it is replaced or refurbished with an equal amount of capacity at a reduced cost.

Table AF.1 Economic and technical lifetime assumptions in MTRMR 2016 (years)

Technology	Economic lifetime	Technical lifetime
Hydropower	35	70
Solar PV buildings	20	20
Solar PV utility	20	25
CSP/STE	25	30
Onshore wind	25	30
Offshore wind	25	30
Geothermal	35	50
Bioenergy	20-25	40
Ocean	20	20

Biofuels for transport and renewable heat round out the analysis

The conventional biofuel supply analysis is based on a capacity-driven model. The core of the model is a plant-level database. Given their small and fragmented nature, biofuels plants are difficult to track. The industry also remains volatile, with company exits and consolidations. Still, biofuels capacity can quickly change in response to market conditions. Future production is modelled on installed capacity and utilisation factors in a given country, which is based on historic trends and expected economic and policy developments.

The renewable heat chapter analyses historical trends of the final energy consumption of renewables for heat and presents projections for 2015-21 as output by the industry and building modules of the World Energy Model (WEM) under the New Policies Scenario in the IEA *World Energy Outlook 2016* (IEA, forthcoming). The WEM is a large-scale simulation tool that models global energy demand on the basis of a set of assumptions which are explained in detail in IEA, 2016b. The New Policies Scenario takes into account the policies and implementing measures affecting energy markets that had been adopted as of mid-2016, together with relevant policy proposals, even though specific measures needed to put them into effect have yet to be fully developed. Generally speaking, projections for final renewable energy consumption are made based on future heat demand and the available technology options to meet it in the context of the policy framework as outlined by the New Policies Scenario.

Table AF.2 Central assumptions for global LCOE ranges by technology in 2015

	Typical system costs (USD 2015/kW)	Full-load hours	Annual O&M (% of system cost)	Discount rate (% real)	Economic lifetime
Bioenergy					
Dedicated biomass electricity	800-4 500	7 000	2.5-6.5	7-8	20
Hydropower					
Large plants	1 300-2 500	2 200-6 600	2.5	8-12	35
Small plants	2 030-3 500	2 200-6 600	2.5	8-12	35
Geothermal					
Flash plants	2 000-5 000	7 450	2.5	8-9	35
Binary plants	2 400-5 600	7 450	2.5	8-9	35
Offshore wind					
China	3 500-3 800	2 950	3.5	8-9	25
Germany	4 300-5 000	3 850	3.5	7-8	25
United Kingdom	4 400-4 900	3 850	3.5	8-9	25
Onshore wind					
China	1 125-1 250	1 900	1.5	6.5-7.5	25
Germany	1 600-1 900	2 000	1.5	3-4	25
Japan	2 300-2 600	2 200	1.5	6-7	25
United States	1650-1 850	2 950	1.5	6-7	25
PV – utility					
China	1 200-1 300	1 500	1.0	6-7	20
Germany	1 150-1 250	1 050	1.0	2.5-3.5	20
Japan	1 900-2 100	1 075	1.0	2.5	20
United States	2 100-2 400	1 450	1.0	7-8	20
PV – commercial					
China	1 250-1 500	1 050	1.0	6.5-7	20
Germany	1 300-1 500	1 050	1.0	4.5-5.0	20
Japan	2 400-2 700	1 075	1.0	2.5	20
United States	3 000-3 400	1 300	1.0	8.5-9.5	20
PV – residential					
China	1 500-1 700	1 050	1.0	6.5-7	20
Germany	1 650-1 900	1 050	1.0	2.5	20
Japan	2 900-3 200	1 075	1.0	1.5-2.0	20
United States	3 900-4 200	1 300	1.0	9-10	20
CSP (6-hour storage)					
South Africa	5 100	3 250	1.0	10.5-11.0	25
United States	7 500	3 370	1.0	8	25

Notes: Typical system cost assumptions refer to the time of commissioning of the project kW = kilowatts; O&M = operation and maintenance. Assumptions for construction time: bioenergy – 3 years, large hydro – 5 years, small hydro – 3 years, geothermal – 3 years, offshore wind – 3 years, onshore wind – 2 years, solar PV – 1 year, CSP– 2 years. A more in-depth overview of investment costs and LCOE values for a range of bioenergy systems is provided within the "Bioenergy for power" section.

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1. RENEWABLE ELECTRICITY: REGIONAL FORECAST

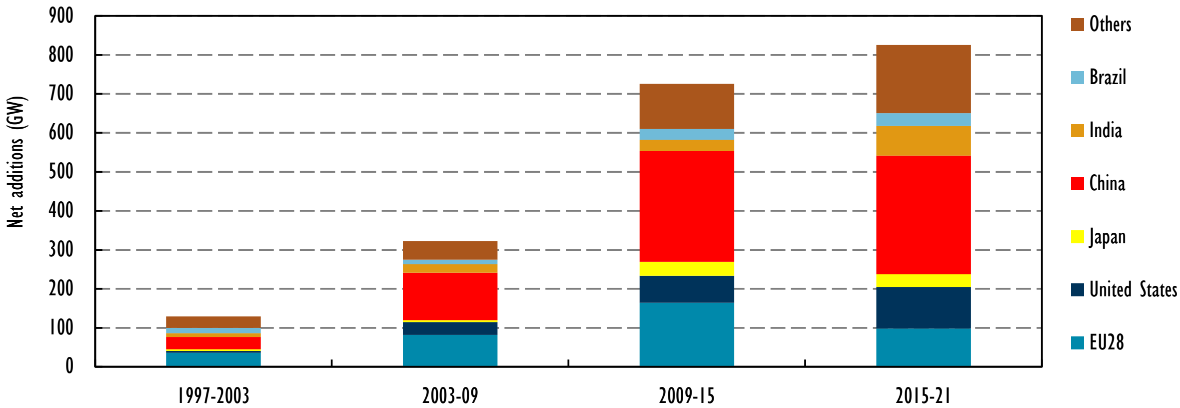
Highlights

- In 2015, annual renewable electricity capacity growth reached a record high at 153 gigawatts (GW), 15% higher than in 2014. For the first time, renewables accounted for more than half of net yearly additions to power capacity and overtook coal in terms of world cumulative installed capacity. Growth continues to be driven by emerging economies (58%) led by The People's Republic of China (hereafter "China") with about 40% of global additions.
- In the *main case* forecast, net global capacity additions of renewables total 825 GW between 2015 and 2021, driven by sustained policy support and continued cost reductions. Overall, this forecast is 13% more optimistic compared to the *Medium-Term Renewable Energy Market Report (MTRMR) 2015.* This revision stems from policy and market improvements in key countries: the United States, responsible for 43% of upward capacity revisions, followed by China, India and Mexico.
- China remains the largest renewable energy market globally with its capacity expanding 60% (305 GW) by 2021. Supported by feed-in tariffs (FITs) and higher indicative government targets for 2020, solar photovoltaic (PV) and wind provide over 80% of China's additional renewable capacity. Renewable integration will continue to be a challenge, especially where electricity demand growth is slowing and there is a strong pipeline of coal, nuclear and renewables capacity.
- The United States has become the second-largest growing market for the first time, with 107 GW of new additions, mostly from wind and solar PV, expected by 2021. The medium-term extension of federal tax incentives has lifted a major policy uncertainty, thus improving investor confidence. In the European Union (EU), renewable capacity is forecast to grow by 23% by 2021. This growth is much slower than the 62% recorded over the prior six years as a result of weak electricity demand growth, pending EU legislation on renewables, market design, and governance of 2030 targets as well as persistent policy uncertainty in a number of key countries.
- India leads the growth in Asia (excluding China) with renewable capacity doubling to almost 160 GW. Competitive tenders and decreasing costs are major drivers, but weak grid infrastructure and off-taker risks limit deployment. In Latin America, renewable growth is expected to be slower than forecast in *MTRMR 2015*, owing mainly to a weaker macroeconomic outlook in Brazil.
- The Middle East and Africa represent only 5% of global renewable growth. Although some tenders have resulted in very low renewable prices in some markets, market barriers, weak grid infrastructure and difficulties in securing affordable financing limit the regions' potential.
- *MTRMR 2016* also considers an *accelerated case* in which enhanced policies and market frameworks in a number of key countries reduce the deployment challenges of grid integration and of economic and non-economic barriers. This leads to an enhanced projection in which capacity growth to 2021 is almost 30% higher. Renewable growth could be 26% higher in China, 46% in India, 26% in the European Union and 23% in the United States (US). In addition, total renewable capacity could be 30% higher in the Middle East and 30% higher in Africa by 2021.

Regional forecast overview

Cumulative renewable electricity capacity is expected to grow from 1 969 GW in 2015 to 2 795 GW by 2021 in the *main case* of the *Medium-Term Renewable Energy Market Report 2016,* driven by strong policy support and cost reductions. Overall, the forecast is more optimistic compared with *MTRMR 2015* by over 13% in terms of net additions to capacity over the medium-term period. This is mainly due to policy and market improvements in key countries such as the United States, China and India. Globally, the share of renewables in total power generation is expected to increase from 23% in 2015 to almost 28% in 2021.

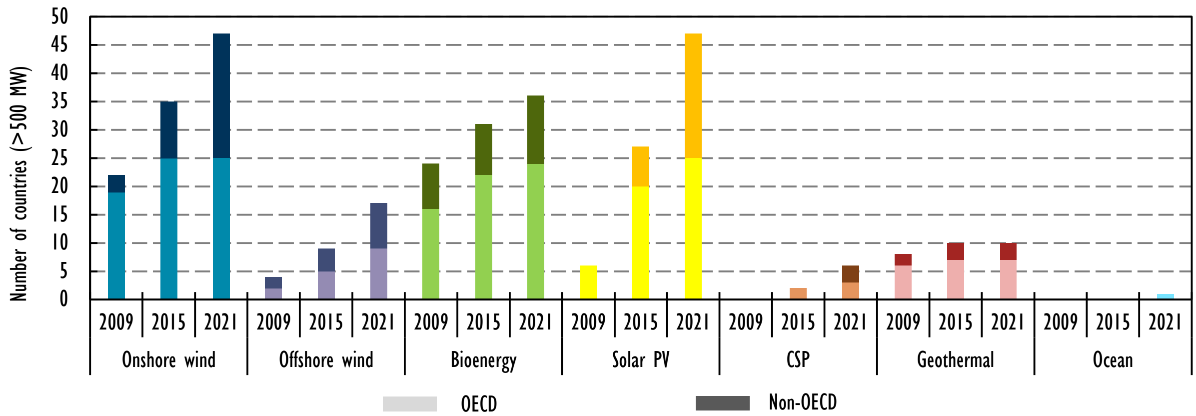
Figure 1.1 Global renewable electricity net additions to power capacity



Six markets provide close to 80% of new renewable additions over 2015-21 (Figure 1.1). China remains the largest market and represents 37% of the additional renewable capacity over the medium term. For the first time, the United States becomes the second-largest-growing market globally, driven mainly by the multi-year extension of federal tax credits. It supersedes the European Union, where renewable policies are in a transitional phase. With the introduction of enhanced policies, India emerges as key engine of renewable growth. Renewable expansion remains robust in Brazil despite macroeconomic challenges and in Japan despite slowing demand growth, with the largest expansion coming from other developing countries all together. Overall, emerging economies and developing countries represent more than two-thirds of the expansion of renewables. This is also reflected by a growing number of new markets: for solar (PV) and onshore wind, around 50 countries are expected to have more than 500 megawatts (MW) of installed capacity by 2021, a steep jump from 2009 levels (Figure 1.2).

In **North America**, the United States is expected to lead growth with the commissioning of over 107 GW of new renewable capacity, resulting in a 50% increase of cumulative renewable capacity compared with 2015. This increase accounts for 43% of total upward forecast revisions to *MTRMR 2015* (Figure 1.3). The long-term extension of federal tax incentives has improved the economics of onshore wind and solar PV, especially in the context of current low natural gas prices, and has been the key driver in their expansion. In Canada, both federal and provincial policy improvements lead to a more optimistic outlook, particularly in Alberta. Mexico's first green certificate and energy auctions have already led to some of the lowest global wind and solar prices. With strong renewable targets in place, long-term contracts awarded in auctions should drive cost-effective wind and solar PV expansion.

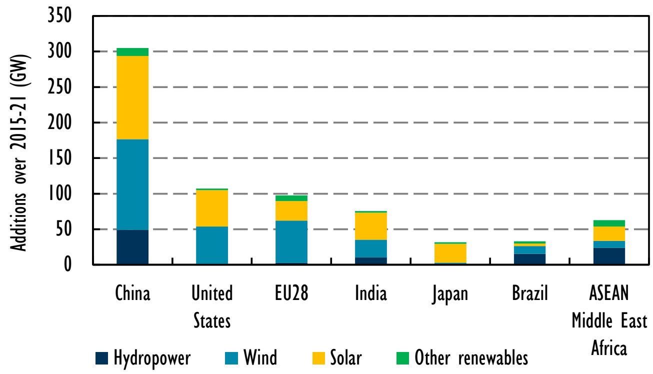
Figure 1.2 Number of countries with non-hydro renewable capacity above 500 MW

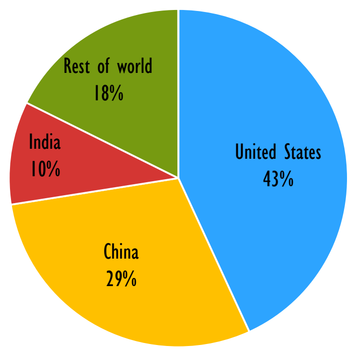


Note: CSP/STE = concentrating solar thermal power; OECD = Organisation for Economic Co-operation and Development.

China's renewable capacity is expected to expand by almost 305 GW through 2021, equivalent to an over 60% increase in cumulative installed capacity. The outlook is more optimistic versus *MTRMR 2015*, driven by growing air pollution concerns and a favourable policy environment with increased preliminary government targets for most renewables. While large-scale hydropower growth is seen slowing down due to increasing social and environmental pressures, onshore wind, solar PV and bioenergy should provide the majority of new additions over 2015-21 driven by FITs. This is also facilitated by concrete action to reduce curtailment, e.g. through new grid expansion and provincial-level minimum renewable generation quotas. However, the continued rapid expansion of thermal and renewable capacity coupled with reduced power demand growth may lead to excess capacity and further integration challenges.

Figure 1.3 Renewable capacity additions by key countries (left) and net forecast revision from *MTRMR 2015* (right)





Notes: MENA = Middle East and North Africa; SSA = sub-Saharan Africa. Forecast revision indicates net capacity additions over the six-year forecast period. For IEA (2015c), *MTRMR 2015,* this period was from 2014-20.

In **Asia and Pacific** (excluding China), India leads the regional expansion with 76 GW of new renewable capacity expected over 2015-21, almost doubling its current total renewable capacity. An improved policy environment, competitive tenders and decreasing renewable costs are major drivers for the more optimistic solar PV outlook, which leads this growth. For onshore wind, reduced tax incentives pose a moderate challenge to deployment, but a new tender policy is anticipated to drive more sustainable growth. However, issues concerning grid availability, off-taker risks and high financing costs remain forecast uncertainties**.** In Japan, solar PV dominates renewable capacity, driven by a generous FIT, but a changing regulatory environment and grid integration challenges slow its growth over 2015-21. FITs also support rapid expansion of bioenergy deployment. In the Association for Southeast Asian Nations (ASEAN), bioenergy, onshore wind and solar PV should ramp up slowly, driven by FITs as hydropower additions slow over the medium term.

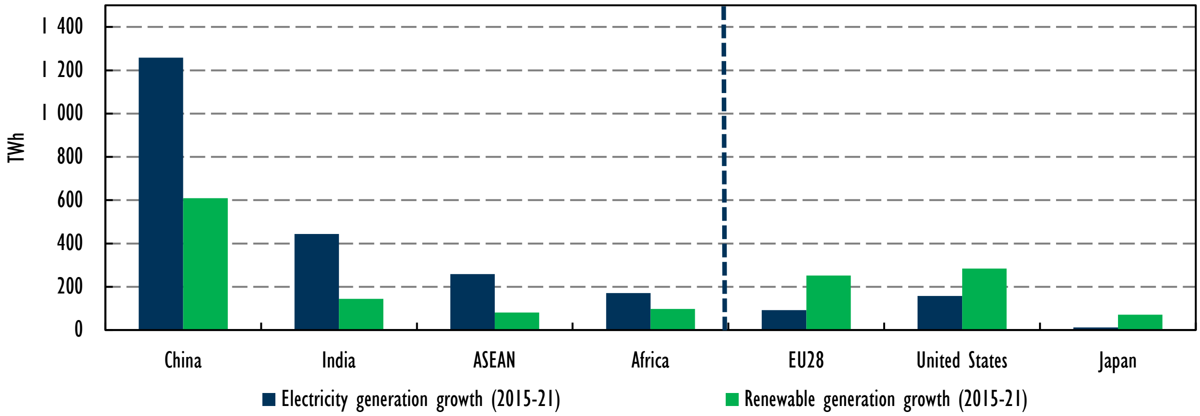
In the **European Union,** renewable capacity is anticipated to grow by 98 GW over 2015-21, led by wind, solar PV and bioenergy amid weak growth in electricity demand and oversupply in some markets. Many countries are transitioning from FITs and green certificates to competitive auction and feed-in premium mechanisms to achieve more cost-effective deployment for utility-scale projects. However, policy and regulatory uncertainties remain, both at the EU level relating to the governance of 2030 renewable targets, and at country level for some key markets (the United Kingdom, Germany and Poland), which affect growth prospects.

In **Latin America,** competitive energy tenders have been the major driver for cost-effective renewable deployment. Governments are expected to auction less capacity over the medium term as power demand slows due to current macroeconomic challenges. Brazil alone represents 62% of the regional renewable capacity growth (33 GW) with hydropower leading the forecast, followed by onshore wind and solar PV. However, despite strong development financing availability, increasing exchange rate risks and interest rates are expected to pose financing challenges to developers. In Chile, solar and wind expansion is seen improving the diversification of the electricity mix, but weak grid infrastructure remains a barrier to deployment.

In the **Middle East and North Africa,** government-backed tenders are expected to drive the majority of renewable capacity growth (18 GW), led by solar PV and onshore wind. Although some tenders resulted in very low renewable prices, regulatory barriers and grid infrastructure increase forecast uncertainty. Hydropower will continue to dominate renewable capacity growth in **sub-Saharan Africa;** it is seen making up half of new renewable capacity over 2015-21. South Africa's renewable procurement programme remains the engine of the region's growth for solar PV and onshore wind, but grid integration poses challenges. In **Eurasia,** challenges related to financing, regulation and policy implementation limit renewable market expansion.

Globally renewable electricity growth over the medium-term is expected to meet about 60% of global incremental power demand needs. However, the pace at which power sector decarbonisation occurs varies by region (Figure 1.4). In most developed countries, renewable electricity generation growth will outpace demand needs leading to faster decarbonisation of the power sector such as in the European Union, Japan and the United States. In most emerging economies and developing countries, renewables are growing fast but demand is growing faster. In China, renewables will account for 40% of electricity demand growth while in India and South East Asia fossil fuels should provide a significant majority of fast-growing power demand.

Figure 1.4 Electricity and renewable generation growth (2015-21)



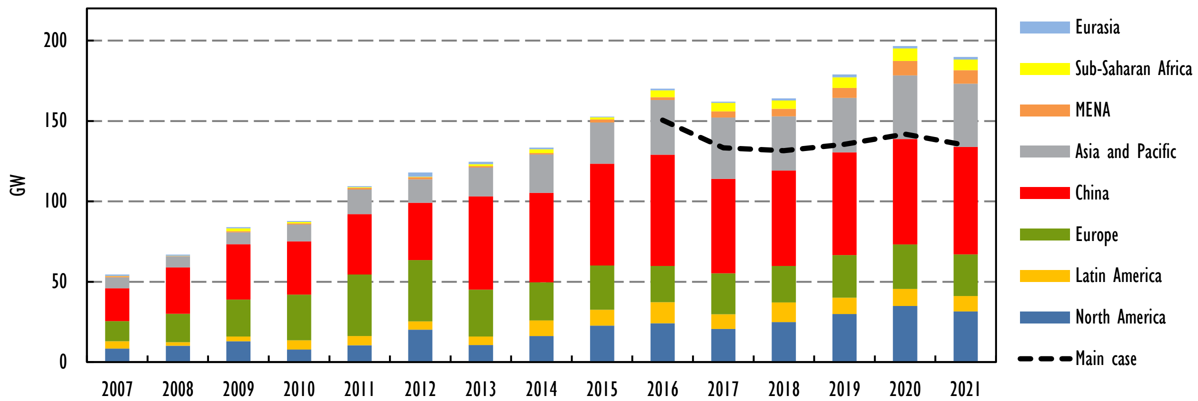
Source: Total electricity generation estimates are from IEA (forthcoming), *World Energy Outlook 2016*.

Over 2015-21, renewable capacity growth could be almost 30% higher than in the *main case forecast* and follow a rising annual trend (Figure 1.5). An accelerated deployment is possible with enhanced policy and market frameworks. Under the *MTRMR accelerated case* projection, China and India together account for half of the additional growth, followed by the United States, Germany and Brazil. The Middle East and Africa also hold great potential.

Achieving the *accelerated case* would require a number of policy and market improvements, including:

- **China:** Faster commissioning of hydropower projects in the pipeline, tackling legal and financing challenges to the deployment of distributed solar PV, and improving grid integration for wind and solar projects.
- **United States:** Early implementation of the Clean Power Plan (CPP) in states with limited renewable capacity deployment and rapid ramp-up of project pipeline to qualify for full Production Tax Credit (PTC) and Investment Tax Credit (ITC).
- **India:** Clarification of tender mechanism and policy uncertainty for onshore wind, better state implementation of federal renewable portfolio standards for solar PV, improvements in financial health of state utilities and tackling grid integration issues.
- **Europe:** Implementation of stable and sustainable policy frameworks that give greater long-term revenue certainty to renewables.
- **Brazil:** Rapid improvement in the financing conditions and macroeconomic environment.
- **Africa and the Middle East:** Channelling financing for faster grid infrastructure build-out, introduction of de-risking measures to tackle issues concerning off-taker reliability and increasing concessional financing.

Figure 1.5 Renewable power net additions to capacity under *accelerated* and *main cases*



Note: The region of Latin America excludes Mexico, which is included in North America.

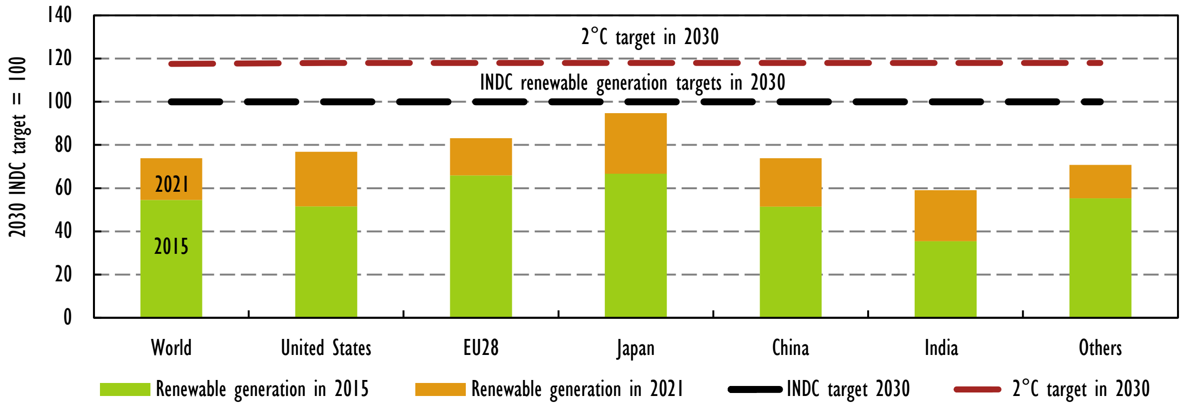
Medium-term forecast and long-term climate goals

More than 180 parties signed the Paris Agreement on climate change, which set an ambitious objective to keep global temperature rise "well below 2°C" and make efforts toward 1.5°C. Of these, more than 75 had already deposited their instruments of ratification, acceptance, approval or accession at the time of writing of the *MTRMR 2016*; these included China, India, the United States and the European Union. On 5 October 2016, the threshold for entry into force of the Paris Agreement was achieved with more than 55 parties accounting for a minimum 55% of the total global greenhouse gas (GHG) emissions ratifying the agreement. Renewables were at the heart of climate negotiations at the United Nations 21st Conference of the Parties (COP21) meeting in Paris, with more than 90 parties outlining renewable energy as a priority area with high mitigation potential in their Intended Nationally Determined Contributions (INDCs),[1] which described their proposed action plan to reduce emissions by 2030. More than 40 countries highlighted renewable electricity as part of their strategy to reduce GHG emissions. INDCs will become NDCs after their ratifications by parties and apply to a period starting from 2021.

MTRMR 2016 main case forecast results show that power generation, which represents around 40% of global energy-related emissions, is currently in line with indicative INDC electricity targets to 2030. In 2015, global estimated renewable electricity generation already accounted for more than half of the modelled INDC targets in 2030 (Figure 1.6). Over the medium term, renewable electricity is anticipated to grow by 36% and represent 28% of global power generation in 2021, when two-thirds of indicative INDC power pledges would be achieved. However, this forecast falls short of what is needed for renewable electricity to meet longer-term climate change objectives. Policies to spur an *accelerated* renewable growth profile, as described above under this report's *accelerated case*, would put the global electricity system on a more firm path to limit the long-term global average temperature increase to 2°C, consistent with the International Energy Agency (IEA) *World Energy Outlook* 450 Scenario.

[1] In this report, the term "INDC" is used to refer to all climate pledges submitted for the Paris Agreement, including those that have been converted to a Nationally Determined Contribution (NDC) by countries that have formally ratified the Agreement.

Figure 1.6 Renewable electricity generation by country indexed to modelled INDC target in 2030



Notes: 2DS = 2°C Scenario. INDC electricity targets are modelled in IEA (2015a), *World Energy Outlook Special Report: Energy and Climate Change*. 2°C target in 2030 modelled in the 450 scenario of IEA (2015b), *World Energy Outlook 2015.*

Asia and Pacific

Recent trends

In the Asia and Pacific (excluding China) region, renewable power generation increased by an estimated 7% in 2015 compared with 2014, reaching close to 715 terawatt hours (TWh). Renewables contributed 15.7% of total electricity generation in 2015, up from 14.8% in 2014. Hydropower still dominates renewable output in the region, but its share is decreasing as a result of growing bioenergy generation in Korea, solar PV in Japan and onshore wind in India. Overall, Asia and Pacific added 26 GW of new renewable capacity in 2015 (Table 1.1), with the majority coming from solar PV (16 GW), followed by hydropower (4.5 GW), wind (3.6 GW) and bioenergy (1.3 GW).

Japan's renewable generation increased by approximately 14% in 2015 versus 2014, primarily due to higher solar PV generation (+11.5 TWh) coupled with record capacity additions over 2013-15. Overall, solar PV capacity grew 10.8 GW and accounted for 93% of all new renewable additions in 2015, driven by the country's generous FIT scheme. Commercial applications (over 10 kilowatts [kW] and less than 1 MW) represented around half of new installations, followed by utility-scale (39%) and residential (9%) projects. Distributed generation dominated the solar PV market, spurred by the country's net metering scheme for residential solar PV in 2009. However, with the introduction of the FIT in 2012, utility-scale projects grew despite facing continued challenges related to grid permits. Smaller renewable additions came from hydropower, bioenergy and onshore wind.

In **Korea,** renewables represent a very small share (3%) of electricity generation. However, cumulative renewable capacity increased from 11.7 GW in 2014 to 13.1 GW in 2015, with solar PV providing the majority of new additions (+1 GW) thanks to the solar set-aside in the country's renewable portfolio standard (RPS) scheme, which replaced the FIT policy in 2012. The country also added record-level onshore wind additions (+0.2 GW) in 2015. Despite increased capacity, Korea's total renewable electricity generation declined by 4.6% from 2014 to 2015, owing to lower hydropower generation.

Table 1.1 Asia and Pacific net renewable capacity additions and % in generation in 2014 and 2015

Asia and Pacific		Net capacity additions (GW)					% of electricity generation				
Country	Year	Hydropower	Wind	Solar PV	Other renewables	Total	Hydropower	Wind	Solar PV	Other renewables	Total
India	2014	1.1	2.3	0.8	0.4	4.6	10%	3%	0%	0%	15%
	2015	1.3	2.6	2.0	0.5	6.4	10%	3%	0%	0%	16%
Japan	2014	0.7	0.1	9.7	0.2	10.7	8%	0%	2%	3%	14%
	2015	0.3	0.2	10.8	0.2	11.6	9%	1%	3%	4%	17%
Korea	2014	0.0	0.1	0.9	0.5	1.5	1%	0%	0%	1%	3%
	2015	-	0.2	1.1	0.1	1.4	1%	0%	0%	1%	3%
ASEAN	2014	2.6	0.4	0.6	0.9	4.5	13%	0%	0%	4%	17%
	2015	2.0	0.3	0.9	0.6	3.8	12%	0%	0%	5%	17%
Australia	2014	0.0	0.6	0.8	0.0	1.3	7%	4%	2%	1%	15%
	2015	-	0.4	0.9	0.0	1.3	6%	4%	2%	0%	13%

Note: Rounding may cause non-zero data to appear as "0.0" or "- 0.0". Actual zero-digit data is denoted as "-".

Sources: 2014 capacity data for OECD countries based on IEA (2016a), *Renewables Information 2016*, www.iea.org/statistics/. All other capacity data from multiple sources; see Chapter 2 technology sources for more detail. Generation data based on IEA (2016b), *World Energy Statistics and Balances 2016*, www.iea.org/statistics/.

In 2015, **India's** renewable electricity generation increased by an estimated 10% from 2014 to reach just under 220 TWh and represented around 16% of the country's power output, with 64% of renewable generation coming from hydropower alone. In 2015, hydropower capacity expanded by 1.3 GW with the largest addition being the Koldam plant (0.8 GW) in Himachal Pradesh. India's solar PV capacity picked up with the addition of 2 GW of new capacity, primarily from utility-scale projects awarded in both national and state auctions. Onshore wind expanded by 2.6 GW driven by the accelerated depreciation (AD) incentive, while its cumulative capacity reached over 26 GW in 2015, making India the fourth-largest wind market globally, surpassing Spain.

In **ASEAN,**[2] renewables accounted for around 17% of total electricity generation in 2015. Hydropower accounted for 70% of renewable output in the region, with Viet Nam alone providing around 45% of this generation. In 2015, hydropower also dominated new renewable capacity expansion, with just over 2 GW becoming operational primarily in Viet Nam and Malaysia. The contribution of non-hydro renewables to power generation remained just over 5%, with the majority provided by geothermal generation in Indonesia and the Philippines. Overall, wind and solar PV additions remain small in terms of both capacity and generation, although they provided roughly 30% of new renewable capacity additions in 2015. Thailand remains the undisputed solar energy leader in the region, alone representing 76% of all solar PV capacity additions in 2015, followed by smaller contributions from Indonesia and Malaysia.

[2] Thailand, Indonesia, Viet Nam, the Philippines, Malaysia and Singapore are considered in this report as the leading six ASEAN countries witnessing the largest energy demand growth, while data for the remaining ASEAN countries are aggregated into the ASEAN total.

In **Australia**, renewable electricity generation fell by 14% in 2015 compared to 2014 as hydropower output contracted by 25% as a result of low reservoir levels. In contrast, solar PV generation increased by nearly 26% from 2014 to 2015 to reach over 6 TWh. Overall, renewables represented around 13% of the total electricity output in 2015, and renewable capacity expanded by 1.3 GW with new additions from solar PV (+0.9 GW) and onshore wind (+0.4 GW). Residential applications represented 70% of these additions, but their share decreased by 85% since 2010 as commercial applications and small utility-scale projects came on line over 2014-15.

Medium-term outlook: Regional main case summary

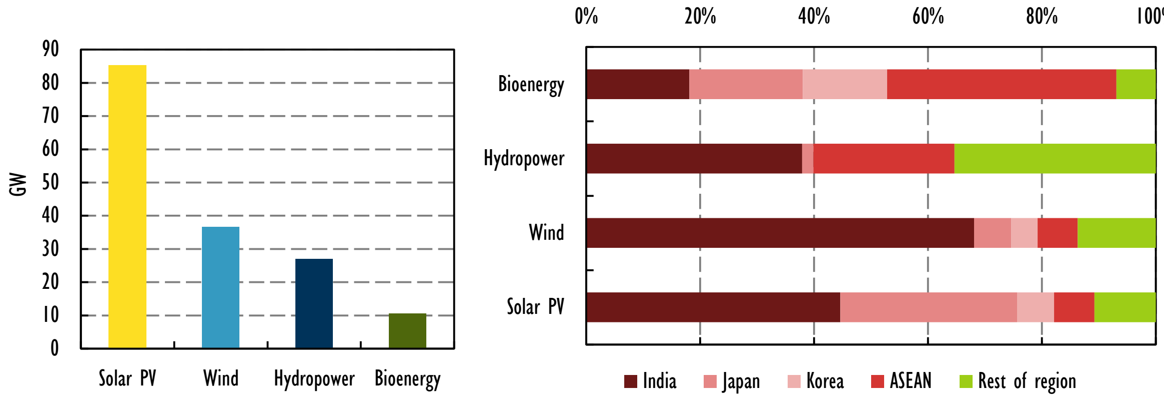
In Asia and Pacific, renewable power generation is expected to increase by 54%, or just under 390 TWh over 2015-21, driven by new generation and energy diversification needs, growing electricity demand, and the need for low-carbon energy systems to reduce pollution impacts and support climate change initiatives in India and ASEAN. Supportive policy frameworks should boost deployment in Japan and Korea. Over the medium term, capacity growth in Asia and Pacific is expected to be led by solar PV, which is forecast to expand by 85 GW, with a growth in generation of over 220%. Onshore wind is expected to follow with capacity additions of 35 GW and generation growth of around 117%. Hydropower is anticipated to grow by 27 GW with India and ASEAN leading, while bioenergy capacity is expected to expand by 10.5 GW with growth spread throughout the region (Figure 1.7). Overall, India and Japan remain the main drivers of renewable capacity growth in Asia and Pacific at 64% of the regional total. India alone accounts for 47% of total renewable capacity additions over 2015-21, followed by Japan at 20%, ASEAN at 13% and Korea at 6%.

Box 1.1 Renewable electricity prospects in Singapore

As a small country with limited natural resources, Singapore imports the majority of its energy. In 2014, natural gas represented around 95% of total electricity generation, followed by oil (3%), while bioenergy and solar PV contributed around 2%. At the end of 2015, Singapore's cumulative solar PV capacity reached around 60 MW.

Looking ahead, solar PV remains the only viable renewable electricity option for the country considering its limited land availability and high population density. In order to further exploit its potential, the government set a target of reaching 350 MW of solar PV capacity (mostly rooftop) by 2020 (Reuters, 2015). This target is supported by the SolarNova auction scheme, which aims at deploying panels on roofs of Housing and Development Board blocks and Ministry of Home Affairs sites. In December 2015, the government held the first tender and awarded 76 MW of new solar PV capacity. Additional tenders are expected in 2016 and 2017. This programme is also supported by the Singapore Economic Development Board. Increasing electricity generation from solar PV is expected to displace relatively expensive oil generation and to contribute to meeting Singapore's increasing peak demand during summer hours, but still faces challenges in deployment amid oil-linked natural gas prices that are keeping retail electricity prices to the consumer low. In addition, Singapore's Public Utilities Board has initiated a project to test floating solar panels to meet electricity needs of water treatment plants. Over the medium term, this report expects Singapore's solar PV capacity to grow by 400 MW to reach 460 MW in 2021.

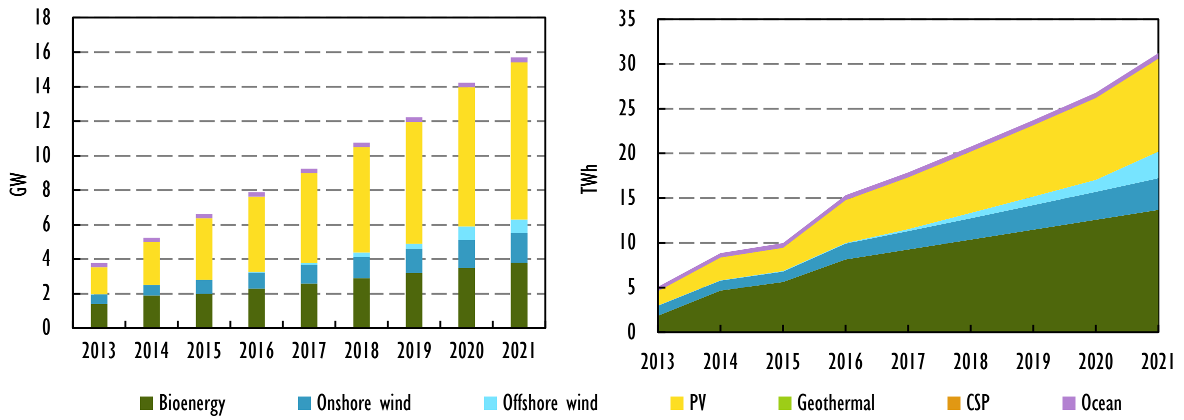
Figure 1.7 Asia and Pacific net renewable capacity additions by technology and country (2015-21)



In **Japan,** solar PV is expected to dominate new renewable capacity additions, although growth will slow over the medium term due to a number of uncertainties regarding grid constraints, the progress of planned electricity market reforms and the country's policy transition from the FIT to auctions for large-scale projects. The government is facilitating the cancellation of solar PV projects that are FIT-certified if they are unable to submit their final grid connection agreement by the end of March 2017. For new large-scale PV projects (including commercial and utility-scale applications), the government announced a tender scheme that is expected to be opened in April 2017. For other technologies, the FITs are expected to spur growth over the medium term, particularly for bioenergy. Renewable generation is anticipated to reach around 240 TWh in 2021 attaining levels close to the government's 2030 target (22-24% of total electricity generation, or 240 TWh to 250 TWh) (METI, 2015a). The details of Japan's forecast are discussed in the country dashboard following this section.

In **Korea,** renewable generation is expected to increase by close to 23 TWh over 2015-21 to reach an estimated 38 TWh by 2021 (Figure 1.8). The country's RPS goal aims to increase the share of renewables in electricity generation from more than 2% in 2012 to 10% in 2024. The continuation of the recent trend by Korean utilities to co-fire biomass with coal in order to meet their RPS obligations remains an uncertainty in forecasting bioenergy generation (see bioenergy section for additional details). Considering recent co-firing trends, this report expects that bioenergy generation will continue to grow rapidly over the medium term from close to 6 TWh in 2015 to almost 14 TWh in 2021. However, the government recently introduced a voluntary implementation plan in order to achieve a more diversified expansion of renewable technologies. The implementation of this new plan could alter the generation forecast presented in this report. Solar PV is expected to provide the largest new capacity additions in Korea, with 5.6 GW coming on line over the medium term, an increase of 156%. While utility-scale installations are likely to be driven by RPS demand, residential and commercial applications are eligible for capital grants, which are expected to facilitate deployment.

Figure 1.8 Korea's cumulative renewable capacity and generation, (2013-21) (excluding hydropower)



Note: Co-firing of biomass undertaken in accordance with national RPS legislation is included within renewable generation but not reflected in capacity data.

Sources: Historical capacity data for OECD countries based on IEA (2016a), *Renewables Information 2016*, www.iea.org/statistics/. Historical generation data from IEA (2016b) *World Energy Statistics and Balances 2016*, www.iea.org/statistics/.

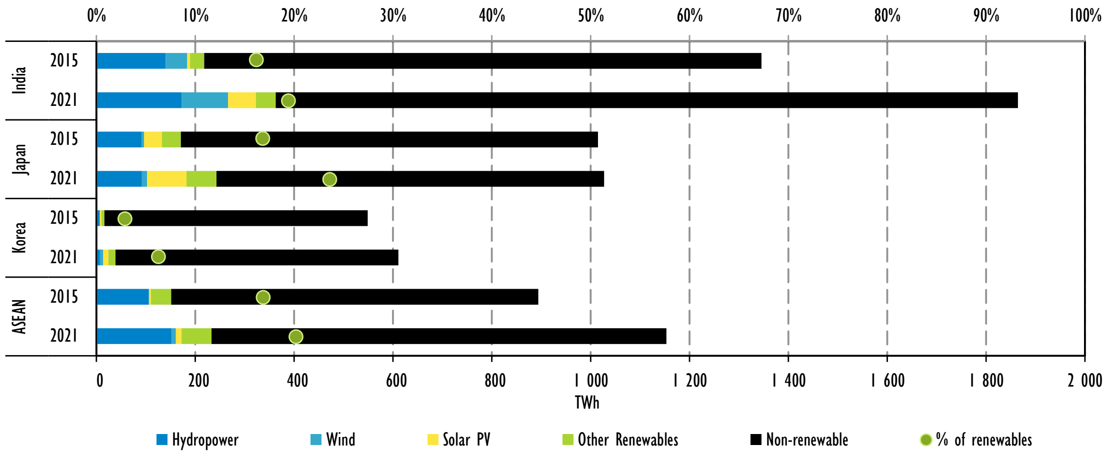
Korea's wind capacity is forecast to grow by 1.7 GW, just under half of which is expected to come from offshore projects. Around 40% of wind capacity additions should be located in Jeju Island, where the government initiated the Carbon-Free Island project to support renewable deployment. Despite Korea's ambitious offshore wind targets, project activity remained limited, and some domestic manufacturers announced their withdrawal from the government offshore wind tender in 2015. Overall, the share of renewables in overall generation is seen increasing from 3% in 2015 to around 6% in 2021 with the expected expansion of non-hydro renewables over the medium term.

India set an ambitious renewable capacity target of 175 GW by 2022. Overall, India's forecast is more optimistic, with renewable capacity expected to grow by almost 76 GW over the medium term, versus 66 GW in *MTRMR 2015.* This upward revision is due to much higher capacity additions of solar PV, which are anticipated to account for 50% of all new renewable capacity growth over the medium term. Onshore wind is expected to expand by 25 GW over the medium term thanks to a strong project pipeline, new supportive policies to encourage the repowering of old sites, and the announcement of wind auctions to develop 1 GW of capacity that should drive additional growth after 2018. However, the scaling back of AD from 80% to 40%, which will come into effect at the end of fiscal year (FY) 2016, and the pace of implementation of recently announced wind auctions remain forecast uncertainties. Hydropower capacity is expected to expand by over 10 GW alongside solar PV and onshore wind, driven by the government's 5 GW small hydropower[3] target by the end of the country's 12th Five-Year Plan (FYP) in 2022. The increasing policy focus on small hydropower should partly offset delays in large-scale hydropower projects due to increasing environmental concerns. India's agreement with Bhutan to co-develop over 2 GW of mostly large hydropower projects should also contribute. Overall, the weak grid infrastructure in India is seen posing challenges to renewable deployment over the medium term, but the grid integration of variable renewables remains an

[3] The IEA defines small hydropower as projects or units as less than or equal to 10 MW while India's target defines small hydropower as less than or equal to 25 MW.

important focus of the government with its green corridor programme and the national smart-grid mission. Overall, the share of renewables in power generation is expected to grow from 16% in 2015 to 19% in 2021. Details of the India forecast are discussed in the country dashboard following this section.

Figure 1.9 Asia and Pacific electricity generation by source and share of renewables in 2015 and 2021



Source: Total electricity generation estimates are from IEA (forthcoming), *World Energy Outlook 2016*.

In **Australia**, renewable capacity is expected to grow by 9 GW over the medium term while generation is forecast to increase by 70% to reach 54 TWh in 2021. Solar PV is anticipated to drive capacity growth with 5 GW, mostly from commercial and residential projects, although some utility-scale projects in the pipeline are seen coming on line over the medium term. Continued solar PV cost reductions and relatively high retail prices created a situation of socket parity in most major Australian cities. Small renewable energy certificates, which provide an upfront payment to commercial and residential installers (40 Australian dollars per megawatt-hour) based on their estimated electricity generation over 15 years, should continue to make residential and commercial projects economically attractive. For onshore wind, the outlook is more pessimistic with the reduction of the large-scale renewable energy target in June 2015, which remains a forecast uncertainty over the medium term.

Table 1.2 Asia and Pacific cumulative renewable energy capacity in 2015 and 2021

Total capacity (GW)	2015				2021			
	India	Japan	Korea	ASEAN	India	Japan	Korea	ASEAN
Hydropower	45.5	49.9	6.5	39.2	55.7	50.4	6.5	45.9
Bioenergy	5.6	3.6	2.0	5.9	7.7	6.0	3.8	9.4
Onshore wind	26.1	2.9	0.8	0.7	51.1	4.9	1.7	3.2
Offshore wind	-	0.1	0.0	0.0	-	0.5	0.8	0.1
Solar PV	5.1	34.1	3.6	2.5	43.1	60.6	9.1	8.6
CSP/STE	0.2	-	0.0	0.0	0.4	-	-	0.0
Geothermal	-	0.5	-	3.4	-	0.6	-	4.7
Ocean	-	-	0.3	-	-	-	0.3	-
Total	**82.5**	**91.1**	**13.1**	**51.7**	**158.0**	**123.0**	**22.2**	**71.8**

Note: For further country-level forecasts, see online Excel workbook that accompanies this report at www.iea.org/publications/mtrmr/. Rounding may cause non-zero data to appear as "0.0" or "- 0.0". Actual zero-digit data is denoted as "-".

Table 1.3 Asia and Pacific main drivers and challenges to renewable energy deployment

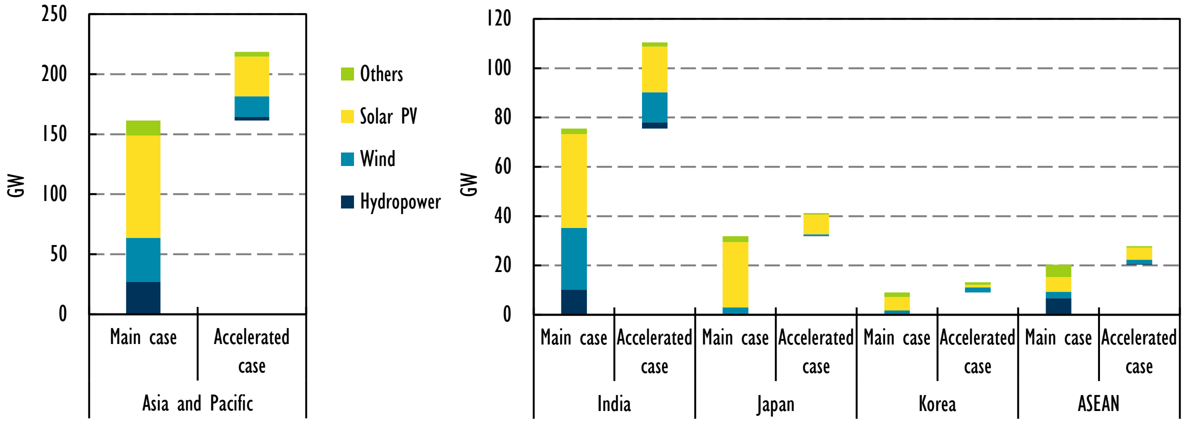
Country	Drivers	Challenges
Japan	Generous FIT scheme supported by government targets. Introduction of competitive auction scheme for large-scale solar PV.	High investment cost of solar PV and wind. Long lead times by environmental assessments and local agreements for wind and geothermal. Grid integration challenges and low interconnection in many provinces.
Korea	Reliance on fossil fuel imports. Government's 10% RPS target by 2024.	Slow deployment of offshore wind. High construction costs for renewable energy projects.
India	Robust and supportive policy environment with ambitious targets and competitive auction schemes, strong financial incentives. Growing power demand and electrification needs; captive and rural needs support distributed PV.	Lack of synchronisation of national policies at the state level. Weak grid infrastructure and management. Inability to secure PPAs and financial closure. Changing policy support for wind.
ASEAN	Excellent resource availability and rapid rising power demand. Reliance on fossil fuel imports drives the push for increased energy security. Solar FITs and tenders in Indonesia, Malaysia, Philippines and Thailand.	Complexity of regulatory/support framework for renewable energy. Underdeveloped grid infrastructure. Investment returns for renewables remain low compared with fossil fuels.

In **ASEAN,** renewable capacity is forecast to increase by over 20 GW, while renewable generation is anticipated to reach over 230 TWh by 2021. Hydropower is expected to lead the forecast, followed by solar PV, bioenergy and onshore wind. The region will also account for the largest geothermal capacity growth globally, led by the Philippines and Indonesia. As the region's energy mix is highly dependent on fossil fuels (ASEAN is witnessing a sharp rise in oil imports), countries are looking to renewable energy as a way to diversify their energy mix, meet growing energy demand, reduce local air pollution and increase energy access to several off-grid communities. In 2016, ASEAN leaders put forward an aspirational target to increase the share of renewables (excluding traditional biomass) in the region's energy mix to 23% by 2025. The share of renewables in generation was 17% in 2015 and is expected to grow slowly to only 20% by 2021 due to strong growth in fossil fuel generation. Despite these drivers, grid infrastructure and complex regulatory environments in some countries are expected to pose significant barriers to renewable deployment over the medium term. The details of the ASEAN forecast are discussed in the dashboard following this section.

Medium-term outlook: Regional accelerated case summary

Overall, the potential for additional renewable deployment in Asia and Pacific is large, and renewable capacity growth could be up to 35% (57 GW) higher over 2015-21 versus the *main case*. India alone represents approximately one-third of the regional additional growth, followed by Japan, ASEAN and Korea (Figure 1.10).

Figure 1.10 Asia and Pacific renewable capacity additions (2015-21), main versus accelerated case



In **India,** the accelerated deployment of renewables over the medium term could be 46% higher and is primarily dependent on the success of the country's many cross-cutting reforms to improve state electricity board governance, increase compliance levels of the Renewable Purchase Obligation (RPO), and improve the financial health of insolvent distribution companies. Accelerated deployment will require increased state participation in the country's Ujwal DISCOM Assurance Yojana (UDAY) scheme to open up the banking system and financially restructure distribution companies as well as continued efforts to expand and upgrade the country's grid infrastructure. Better synchronisation among national goals and state-level policy implementation will be necessary to support further uptake of solar PV (which could add an additional 19 GW compared with the *main case*) and successful implementation of future onshore wind auctions, while the diversification of financing sources could bring the cost of debt down and improve the economic attractiveness of renewables.

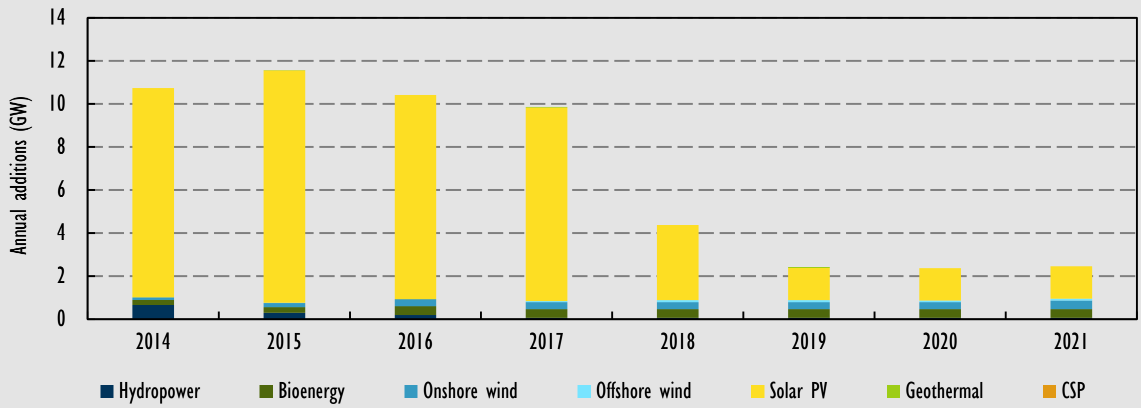
In **ASEAN**, continued introduction and implementation of reforms to fossil fuel subsidies can level the playing field for renewables. Overall, higher levels of implementation of grid infrastructure plans could spur faster deployment of renewables in the region. ASEAN's renewable capacity additions can be close to 8 GW higher over the medium term under the accelerated case, with solar PV accounting for 5 GW of the additional growth. Accelerated growth in solar PV will depend primarily on deployment levels in Thailand and Indonesia, where the potential for solar PV is greatest. Further uptake will be contingent on both countries' ability to overcome challenges related to grid connection and licensing delays, as well as a continuation of solar incentives in Thailand and higher FIT capacity quotas in Indonesia. In addition, policy improvements stimulating small-scale distributed capacity could result in overall higher capacity growth in the region. Onshore wind has the potential to be the second-largest contributor to accelerated deployment led by Thailand (1.1 GW) and Indonesia (530 MW). An upward revision of the FIT in Viet Nam, which were unavailable at the time of writing, and improvements in permitting procedures could unlock a portion of the pipeline of onshore wind projects.

In **Japan**, an accelerated case will depend on improvements in grid integration of variable renewables and some policy enhancements set to come into force with the unbundling of the power sector in April 2020. Solar PV represents the largest potential extra growth with an additional 8 GW, but this will depend primarily on project developers' ability to sign timely grid connection agreements before the April 2017 deadline in order to keep their FIT contract. In addition, Japanese deployment would benefit greatly from faster cost reductions from successful implementation of the new auction scheme for large-scale applications. For other renewables, a smoother permitting process would unlock the deployment of additional onshore wind projects (570 MW). Bioenergy capacity could be 600 MW higher depending on whether project developers ensure sustainable fuel supply chains and financial agreements as scheduled.

In **Korea,** renewable capacity could be 4 GW higher by 2021 depending on the rate at which the utilities implement their RPS goals. Faster deployment of onshore wind would depend on streamlined grid connections, and faster-than-expected cost reductions could spur higher solar PV capacity by another 1 GW.

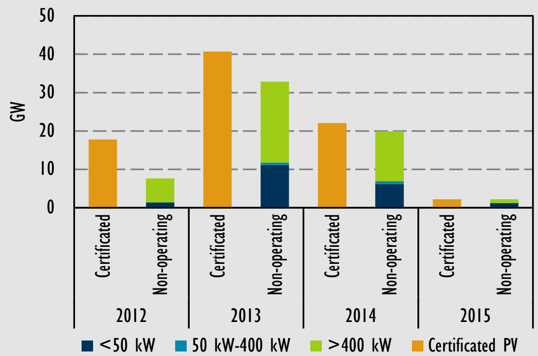
Japan dashboard

Figure D.1 Japan annual net additions to renewable capacity (2014-21)



Source: Historical OECD capacity derived from IEA (2016a), *Renewables Information 2016*, www.iea.org/statistics/

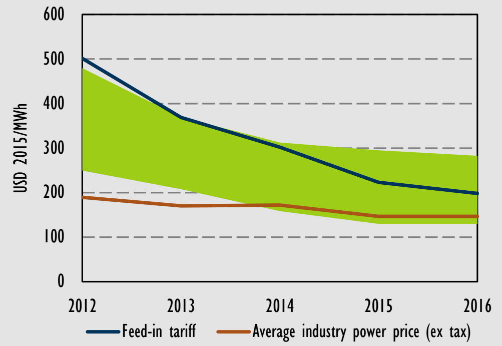
Figure D.2 Solar PV FIT-certificated versus non-operating solar PV capacity



Notes: Solar PV certificate in 2015 is data as of September 2015. The years present FY base. Non-operating PV is at risk of being cancelled.

Source: METI (2015b), Status of Solar PV in Certificate and Commission.

Figure D.3 Japan commercial and utility-scale solar PV LCOEs vs FIT and end-user prices



Notes: LCOEs and FIT as of mid-year; end-user prices are annual averages. The ranges reflect low-cost, typical and high-cost projects which vary primarily due to differences in system costs, resources and financing costs

Table D.1 Japan renewable power capacity (GW)

	2015	2017	2019	2021	2021*
Hydropower	49.9	50.2	50.3	50.4	50.6
Bioenergy	3.6	4.4	5.2	6.0	6.6
Onshore wind	2.9	3.5	4.2	4.9	5.5
Offshore wind	0.1	0.1	0.3	0.5	0.5
Solar PV	34.1	52.6	57.6	60.6	68.6
CSP/STE	-	-	-	-	-
Geothermal	0.5	0.5	0.6	0.6	0.6
Ocean	-	-	-	-	-
Total	91.1	111.3	118.2	123.0	132.3

* Accelerated case. Rounding may cause non-zero data to appear as "0.0" or "-0.0". Actual zero-digit data is denoted as "-".

- **Drivers**
  - continuous FIT scheme and supportive policy with a clear 2030 renewable generation target
  - introduction of competitive auction scheme for large-scale solar PV.
- **Challenges**
  - costs of solar PV and wind remain high
  - grid integration challenges in some regions
  - long lead times of environmental permitting and local agreements for wind and geothermal.

Medium-term forecast: Japan main case

Japan's renewable generation is expected to expand by over 70 TWh over the medium term, driven by the need to diversify the power sector and backed by robust incentives. Overall, capacity growth is anticipated to be lower versus *MTRMR 2015*, with solar PV capacity revised down owing to recent regulatory changes.

New solar PV regulation is expected to reduce the FIT-approved PV project pipeline significantly. The Ministry of Economy, Trade and Industry (METI) approved FIT eligibility for over 80 GW of solar PV projects since July 2012; however, fewer than 30 GW of these projects were commissioned. At the end of 2015, METI estimated that 70% of projects that were certificated with high FIT prices in 2012-13 were not yet operational (METI, 2015b). In May 2016, the government passed a new regulation that requires FIT-approved projects that have not been commissioned to submit their grid connection contracts by April 2017. With the new regulation, METI aims to cancel projects that are not viable. This report expects the majority of projects, especially those that received FIT approvals in 2012-13, will be cancelled. For new solar PV projects permitted in 2017, grid connection agreements became a requirement for FIT eligibility going forward. Overall, considering the current project pipeline, it is expected that solar PV installation will slow significantly.

The introduction of an auction scheme in 2017 and retail competition are expected to offer new opportunities for solar PV, but implementation remains an uncertainty. Japan's large-scale solar PV LCOE is estimated at USD 130/MWh to USD 300/MWh, significantly higher than the global reference of USD 100/MWh to USD 150/MWh. This is due to lack of competition in the solar PV supply chain spurred by a generous FIT, as well as high installation costs. Although detailed information on the auction design was not available at the time of writing, price competition is expected to bring significant cost reductions. Over the medium term, decreasing solar PV costs, coupled with retail competition, can create new self-consumption opportunities, including energy storage, especially for commercial projects. However, uncertainty remains over the level of competition, as full unbundling of vertically integrated electricity power companies (EPCOs) is due by 2020.

Additional grid capacity was announced for renewables, but integration challenges remain in some areas. In November 2015, 1 GW of solar PV and 1.7 GW of onshore wind additions were approved (METI, 2015c). However, some EPCOs raised integration challenges of solar PV in areas where high PV penetration is coupled with low demand and limited transmission capacity. Despite revised dispatch rules in January 2015, integrating solar PV into EPCOs led to an excess in grid capacity. It is expected that the unbundling of EPCOs will help to address the grid capacity challenges through enhancement of flexibility, including frequent usage of inter-regional transmissions.

Over the medium term, solar PV is expected to lead renewable capacity growth. Solar PV capacity additions over 2016-17 remain strong with the addition of 9 GW. However, net annual additions will fall to 1.5 GW from 2019-21 due to the cancellation of projects and grid constraints. Commercial and residential applications will likely lead the expansion, as the majority of projects to be cancelled are large-scale ones. Onshore wind is likely to increase by over 2 GW over the medium term, while offshore wind growth of 400 MW is expected. Bioenergy capacity is forecast to grow by 2.4 GW, driven by the pipeline of projects registered under the country's FIT scheme.

Medium-term forecast: Accelerated case

Overall, accelerated deployment will require rapid implementation of electricity market reforms and further flexibility improvement to tackle integration challenges. Further uptake of renewables will depend on increasing market access and competition and decreasing renewable energy costs to international benchmark levels. Solar PV capacity can be 8 GW higher in 2021 with increased deployment for self-consumption applications in commercial and industrial buildings and faster commissioning of projects awarded in the upcoming auctions. Onshore wind capacity can be slightly higher with a more streamlined permitting process. In addition, timely financial agreements can facilitate the commissioning of FIT-approved bioenergy.

India dashboard

Figure D.4 India net additions to renewable capacity (2014-21)

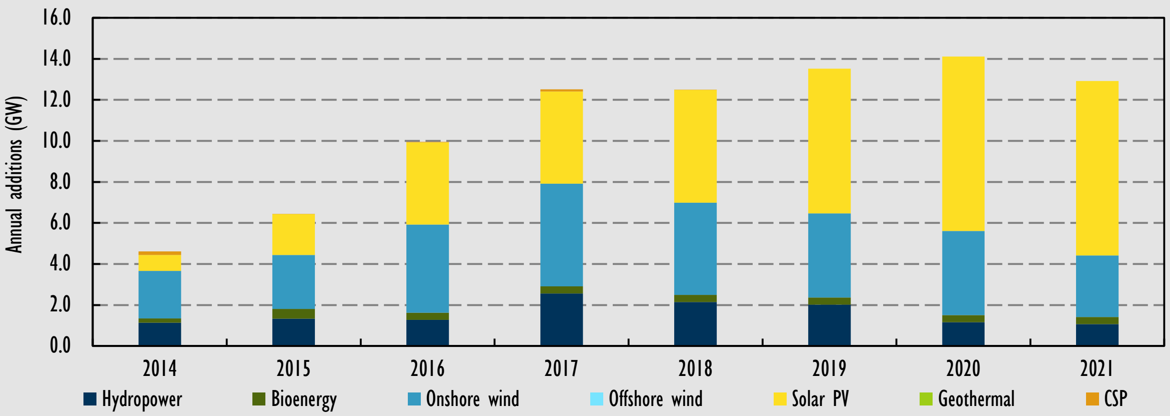
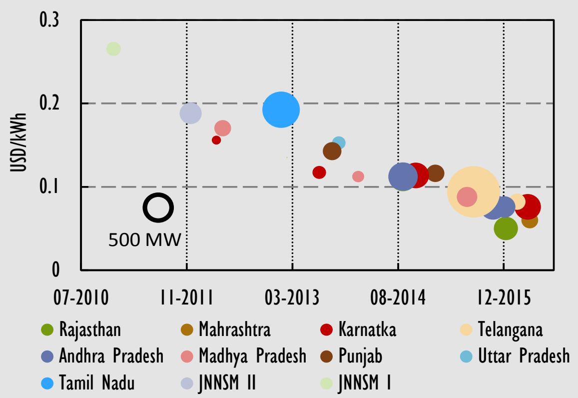
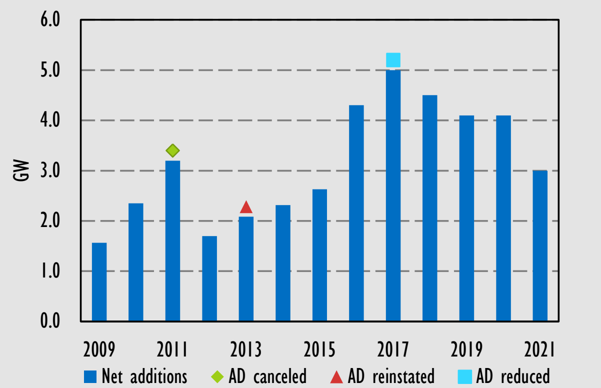


Figure D.5 Weighted average PPA bid prices in solar PV auctions, state and JNNSM, (2010-16)



Note: PPA = power purchase agreement; JNNSM = Jawaharlal Nehru National Solar Mission; kWh = kilowatt-hour.

Figure D.6 Historical and forecasted wind capacity additions with AD incentive



Notes: AD = accelerated depreciation. Wind auctions expected in late 2016 may offset the effect of the new AD policy, but y-o-y growth is still expected to slowly.

Table D.2 India renewable power capacity (GW)

	2015	2017	2019	2021	2021*
Hydropower	45.5	49.3	53.5	55.7	58.2
Bioenergy	5.6	6.3	7.0	7.7	9.4
Onshore wind	26.1	35.4	44.0	51.1	63.3
Offshore wind	-	-	-	-	-
Solar PV	5.1	13.6	26.1	43.1	61.6
CSP/STE	0.2	0.4	0.4	0.4	0.4
Geothermal	-	-	-	-	-
Ocean	-	-	-	-	-
Total	82.5	105.0	131.0	158.0	193.0

* Accelerated case. Rounding may cause non-zero data to appear as "0.0" or "-0.0". Actual zero-digit data is denoted as "-".

- **Drivers**
  - **- robust and supportive policy environment with ambitious targets and competitive auction schemes, strong financial incentives**
  - **- growing power demand and electrification needs; captive and rural needs support distributed PV.**
- **Challenges**
  - **- lack of synchronisation of national policies at the state level**
  - **- weak grid infrastructure and management**
  - **- Inability to secure PPAs and financial closure**
  - **- changing policy support for wind.**

Medium-term forecast: India main case

India's renewable capacity is expected to expand by over 75 GW over 2015-21, driven by strong generation needs, good resource availability, attractive economics and policy improvements. The outlook is more optimistic versus *MTRMR 2015* with a stronger forecast for solar PV despite lower hydropower additions. However, stability of financial incentives, state-level policy implementation and weak grid infrastructure continue to pose challenges to renewable deployment.

Increasing competition in auctions is paving the way for more utility-scale solar PV, but will require better policy implementation at the state level. In January 2016, the federal reverse bid auction in Rajasthan resulted in the lowest bid price to date at 4.34 rupees (INR) per kWh (USD 63/MWh) for a 70 MW project, 7% lower than the December 2015 auction in Andhra Pradesh. Other nearly successful bids (ranging from INR 4.40/MWh to INR 4.63/MWh) display developer confidence. However, some state-level auctions resulted in project delays and cancellations over the last two years due to reluctance of state utilities to sign PPAs (Bridge to India, 2016) and challenges in the financial closure of projects. Despite mandatory RPO targets (solar PV was recently increased to 8%) and a strong pipeline of projects, the compliance of the RPO faces challenges, especially under the financial stress of distribution companies, which accumulated losses of USD 57 billion and debt of USD 65 billion as of 2015 (MNRE, 2016). The government initiative to financially restructure public distribution companies is under way and receives state-level support. If successful, the plan can free up financing from the banking sector, but a clear framework is yet to be decided. For residential and commercial projects, in addition to net metering in 27 states, India announced a new capital subsidy programme offering 30% for projects in the public sector to boost deployment for rooftop solar. Under these conditions, solar PV capacity is anticipated to grow by 38 GW, primarily from utility-scale projects.

Recent amendments to incentive schemes are expected to slow wind capacity growth in the first half of the medium term. Historically, India's accelerated depreciation (AD) incentive spurred wind development, with 70% of projects historically taking advantage of it. The expiration of AD in FY 2011/12 resulted in a significant decrease in additions over 2012-13, while its restoration led to renewed growth in the wind market. However, the success of AD was limited to attracting investment in new capacity and failed to incentivise generation. In order to maximise generation and achieve sustainable wind development, the government decided to reduce AD from 80% to 40% as of April 2017, introducing a 1 GW tender scheme for new projects. While the new tender scheme will also include a generation-based incentive (GBI) of INR 0.5/MWh (USD 0.70/MWh), the GBI is also set to expire in March 2017. This report expects a slowdown in wind investment due to this policy transition. Accordingly, onshore wind is forecast to grow 25 GW over 2015-21 with stronger capacity additions in 2016-18 as developers rush before the expiration of the aforementioned incentives.

Increased capacity from other renewable technologies in the power mix is minimal over the medium term. As investors continue to favour solar PV and onshore wind, hydropower growth is expected to slow due to overall planning and land acquisition challenges. Hydropower is likely to increase by just over 10 GW from 2015-21, versus 13 GW projected in *MTRMR 2015.* Bioenergy will achieve higher levels of deployment in the medium term due to a clear role for biomass outlined in India's INDC, which includes a 10 GW target for 2022.

Medium-term forecast: India accelerated case

The possible accelerated growth in renewable energy deployment in India is robust, and capacity additions could be 35 GW higher versus the main case. Solar PV would require improvements in the financial health of state utilities, better state-level implementation of RPOs, faster grid infrastructure expansion and reducing land acquisition barriers. Similar policy enhancements are needed for onshore wind, especially in clarifying the details of the newly introduced auction scheme. Accelerated deployment would require the diversification of renewable financing options to achieve lower cost of capital. In addition, hydropower capacity could see some additional growth with the timely commissioning of projects under development, especially for small hydropower.

ASEAN dashboard

Figure D.7 ASEAN annual net additions to renewable capacity by select country (excluding hydropower)

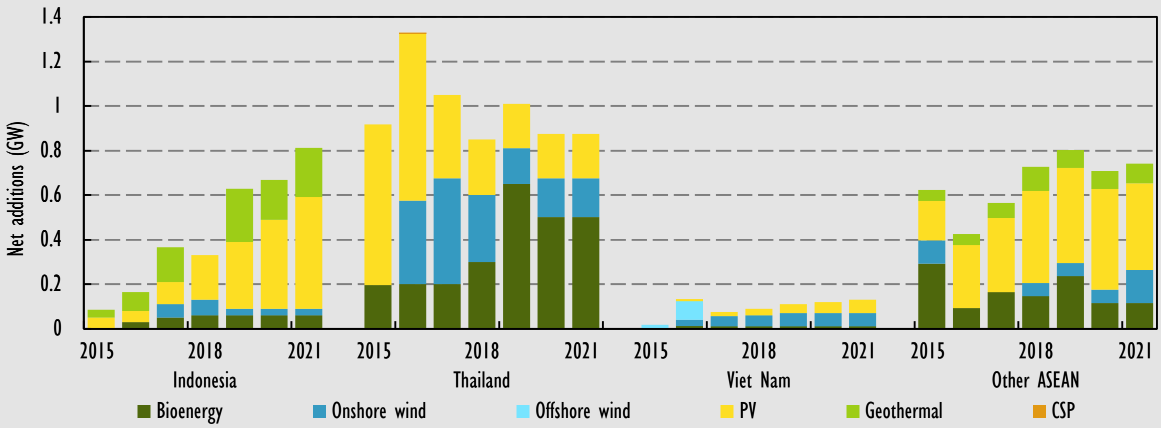


Figure D.8 Renewable generation by technology and country, (2015 and 2021)

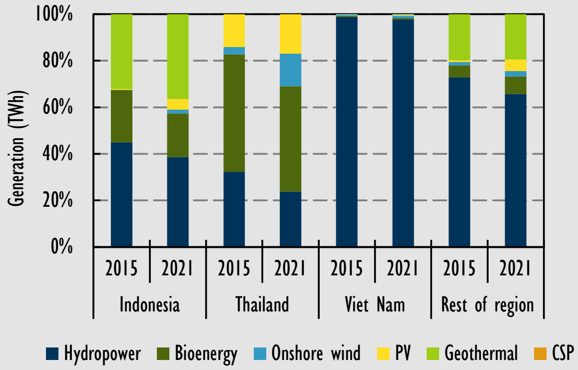
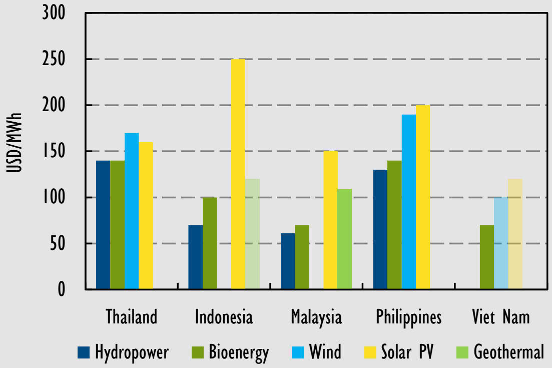
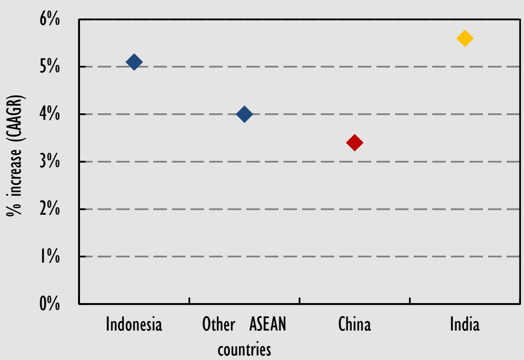


Figure D.9 Average FITs in selected ASEAN countries



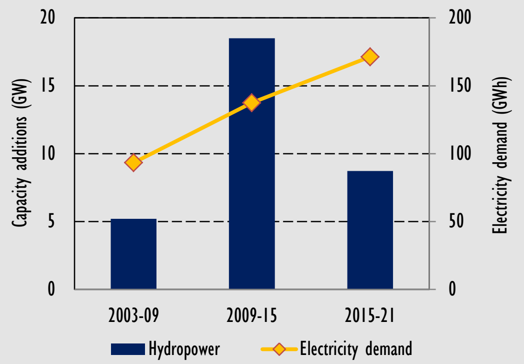
Notes: Faded columns represent FITs under discussion. The solar PV FIT in Indonesia represents the maximum tariff, while the FIT is geographically-based.

Figure D.10 Annual electricity generation growth by country over 2015-21



Note: CAAGR = compound annual average growth rate.
Source: IEA (forthcoming), World Energy Outlook 2016.

Figure D.11 ASEAN hydropower additions and electricity demand (historical and forecast)



Source: Analysis based on IEA (2016b), *World Energy Statistics and Balances 2016*, www.iea.org/statistics/.

Medium-term forecast: ASEAN main case

ASEAN's renewable capacity is expected to expand by over 20 GW from 2015-21, supported by a strong desire to satisfy energy demand growth (expected to grow at an annual rate of 2.2% [CAAGR]) (IEA, 2015b) in a sustainable way. For most of the region, this includes minimising costs, improving energy security and limiting air pollution. As a region with limited non-hydro renewable deployment to date, new solar PV, onshore wind and bioenergy capacity is expected to pick up slowly in an effort to expand and diversify the power sector over the medium term. Geothermal capacity is expected to grow as well, particularly in Indonesia and the Philippines, where untapped potential is still large. Overall, Thailand and Indonesia will account for approximately 55% of new capacity additions in the region over the medium term.

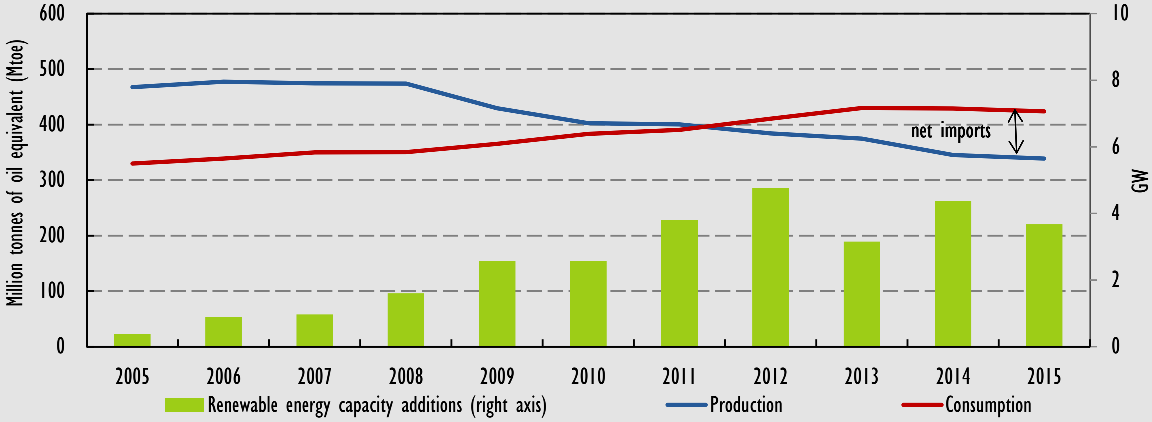
Rising fuel imports are driving reform of fossil fuel subsidies and reshaping the power sector. While some countries in ASEAN are rich in hydrocarbons, the contribution of fossil fuel exports to the region's economies is declining. With decreasing revenues from fossil fuel exports in some countries and an increasing share of natural resources being diverted to the domestic market to meet growing electricity demand, fossil fuel subsidies for both consumption and electricity inputs are increasing the burden on countries' budgets. Fossil fuel subsidies in ASEAN totalled USD 36 billion in 2014 (IEA, 2015b). While coal is expected to remain the cheapest source of electricity generation over the medium term, the reform of natural gas and oil subsidies for electricity production and consumption could unlock some budget for additional economic incentives for renewables, improving their economic attractiveness. Some ASEAN countries introduced renewable targets and incentives in conjuncture with subsidy reforms. For example, Indonesia introduced fossil fuel subsidy reform as a way to achieve energy diversification and increase renewable energy deployment. Thailand established its 15-year Renewable Energy Development Plan in 2008, the same year the country implemented energy price reforms, most notably for gas and electricity tariffs. In 2010, Malaysia introduced fossil fuel subsidy reform and new targets and incentives for renewables.

Substantial non-economic barriers continue to be a major impediment to the deployment of renewables. Despite economic incentives, renewable power deployment still faces challenges, particularly due to administrative and regulatory barriers and grid integration challenges. Lengthy and unclear permitting processes continue to hamper renewable project development, especially in Indonesia, Malaysia and Viet Nam. While nearly every country in ASEAN has significant infrastructure development plans, challenges remain in implementation. Roughly 140 million people in the region still lack access to electricity. In Indonesia and the Philippines, in particular, grid infrastructure is weak and requires upgrades to accommodate higher levels of penetration by renewables. Furthermore, Indonesia's vast archipelago makes getting power to rural communities and connecting to the grid a challenge.

Despite challenges to further development, hydropower is expected to dominate renewable expansion over the medium term. In 2014, hydropower provided 77% of total renewable output in ASEAN, with Viet Nam generating over half. With complicated licensing procedures, land acquisition and permission barriers, administrative challenges, and social acceptance issues, hydropower development in the region is marred with complexities. Overall, growth will slow in the region over the medium term. Despite these challenges, policies consistently back its development, especially in Viet Nam, which is expected to deploy 46% of all new regional capacity additions over 2015-21. A greater focus on small hydropower projects also emerged in Indonesia, the Philippines, Malaysia and Thailand, which have FITs for the technology. Small hydropower is being singled out as a route to accelerating clean energy development in the region. Bilateral and regional co-operation among Lao PDR, Cambodia and Viet Nam is likely to foster small hydro development as well as large-scale hydropower expansion. Continued co-operation will be necessary to reverse the current downward trend, as hydropower development is expected to slow and expand by around 7 GW over 2015-21, only 33% of the regional renewable deployment in the medium term, as opposed to 77% from 2005 to 2014.

ASEAN dashboard

Figure D.12 ASEAN historical renewable capacity additions and TPES and total final consumption patterns



Note: TPES = total primary energy supply; ktoe = thousand tonnes of oil equivalent; RE = renewable energy.

Source: Analysis based on IEA (2016b), *World Energy Statistics and Balances 2016*, www.iea.org/statistics/.

Table D.3 RE goals and solar PV and wind targets of selected ASEAN countries

	Share of RE goal	RE-supportive policies	Solar PV targets	Wind targets
Indonesia	25% by 2025 and 31% by 2050	Fossil fuel subsidy reform; Clean Technology Fund	620 MW (2020)*	970 MW (2025)*
Thailand	20% by 2036	Solar programme; special tax incentives	6 GW (2036)*	3 GW (2036)*
Viet Nam	4.5% by 2020 and 6% by 2030	Tax and land use incentives; AD on fixed assets	12 GW (2030)	6 GW (2030)*
Philippines	15 400 MW by 2030	Duty-free RE material imports; tax exemption from carbon credits	8.7 GW (2030)*	2.3 GW (2030); Become the region's largest wind energy producer*
Malaysia	14% by 2030	Fiscal incentives to companies generating RE; green technology fund	850 MW (2030)*	NA

*Have a FIT for the technology.

Table D.4 ASEAN leading countries in renewable energy capacity (GW)

	2015			2021 main			2021 accelerated		
	Thailand	Indonesia	Viet Nam	Thailand	Indonesia	Viet Nam	Thailand	Indonesia	Viet Nam
Hydropower	3.6	5.3	16.6	4.1	7.0	19.7	4.1	7.1	19.7
Bioenergy	3.0	1.7	0.1	5.4	2.1	0.1	5.2	2.5	0.1
Wind	0.2	0.0	0.1	1.9	0.2	0.5	2.9	0.7	0.5
Solar PV	2.0	0.1	0.0	4.0	1.7	0.2	6.0	4.5	0.2
Geothermal	0.0	1.4	-	0.0	2.3	-	0.0	2.6	-
Total (GW)	8.9	8.6	16.8	15.4	13.1	20.5	18.4	17.4	20.5

Note: Rounding may cause non-zero data to appear as "0.0" or "- 0.0". Actual zero-digit data is denoted as "-".

Solar PV capacity in ASEAN is expected to more than triple, led by Thailand's supportive policy environment. Solar PV deployment in ASEAN is expected to grow modestly by close to 6 GW over 2015-21. Thailand is anticipated to lead this expansion with the addition of almost 2 GW over the medium term thanks to relatively low investment costs and supportive policy. For utility-scale projects, the government stopped new FIT applications in April 2016, but some projects that already received FIT approvals should come on line over the forecast period. It is expected that additional solar PV capacity will come from distributed and self-consumption projects, which are supported by a generous FIT (USD 160/MWh) (BMWi, 2015). Smaller capacity is anticipated to come on line in Malaysia (+0.7 GW), which also launched its first utility-scale solar tender in May 2016, and the Philippines (+0.5 GW), driven by FITs. Viet Nam's economic reforms to open the solar PV sector up to private investment are expected to support 210 MW of new solar PV additions by 2021. In other parts of ASEAN, the deployment is expected to be smaller due to lack of targeted economic incentives.

Wind capacity in ASEAN is anticipated to grow modestly, as incentive schemes are under transition in major markets and non-economic barriers remain. In the Philippines, the FIT (USD 180/MWh) quota of 200 MW is fully allocated. In 2015, the government announced an additional FIT capacity of 200 MW with a lower rate (USD 160/MWh). However, policy uncertainty remains for future development, as the government introduced a new RPS policy while it also considers additional FIT quotas. Under these conditions, this report expects the majority of projects under the FIT scheme to be operational by 2021. In Thailand, close to 1.5 GW of wind capacity is currently eligible to receive a feed-in premium, but the deployment has been limited mainly due to barriers concerning permitting, grid connection and land acquisition. In April 2016, the government announced a new tender scheme only for small-scale (<10 MW). Over the medium term, projects under the previous incentive scheme are expected to come on line. Smaller additions are also expected in Viet Nam (+0.4 GW) driven by the FIT.

Geothermal and bioenergy hold potential for greater deployment in ASEAN, but witness slower growth compared with other renewables. In ASEAN, geothermal and bioenergy technologies provided close to 90% of non-hydro renewable electricity generation in 2015, but their share is expected to decrease to 75% in 2021. In 2015, close to 26% of global installed geothermal capacity was located in the Philippines (2 GW) and Indonesia (1.4 GW). In both countries, investment risks associated with exploratory drilling, high pre-development costs and availability of affordable financing represent the main challenges to geothermal deployment. In Indonesia, recent regulatory reforms should help streamline the licensing process and allow foreign ownership of plants larger than 10 MW. The government also plans to launch tenders in 2016-17 for geothermal working areas to facilitate investment. Overall, Indonesia leads ASEAN's geothermal expansion with close to 900 MW in additional capacity expected over the medium term. Biomass resources are abundant in the region, and technologies for their utilisation are widely present. Improving energy access remains an important driver for increasing bioenergy capacity in Indonesia and Thailand, where the governments have introduced economic incentives and targets. In addition, increasing urban populations are anticipated to drive waste-to-energy projects throughout the region.

Medium-term forecast: ASEAN accelerated case

Renewable deployment in ASEAN is growing, and encouraging signs point to a beginning of a transformation in the region's power generation mix. Renewable growth could be 7.6 GW higher over the medium term, with solar PV accounting for the majority of this additional increase. Nearly 40% of the additional growth could come from Thailand, if the country can overcome challenges related to licensing delays for solar PV projects. Onshore wind could be 1.8 GW higher with the clarification of the tender scheme in Thailand, while greater certainty on the revision of the FIT in Viet Nam could also contribute to the *accelerated case*. For geothermal, Indonesia alone can drive accelerated growth by 340 MW, depending on the pace of implementation of power sector reforms. The accelerated case for hydropower remains limited, especially for large-scale projects, as social and environmental concerns hamper deployment. However, some accelerated growth potential is possible for small hydropower projects in the region.

China

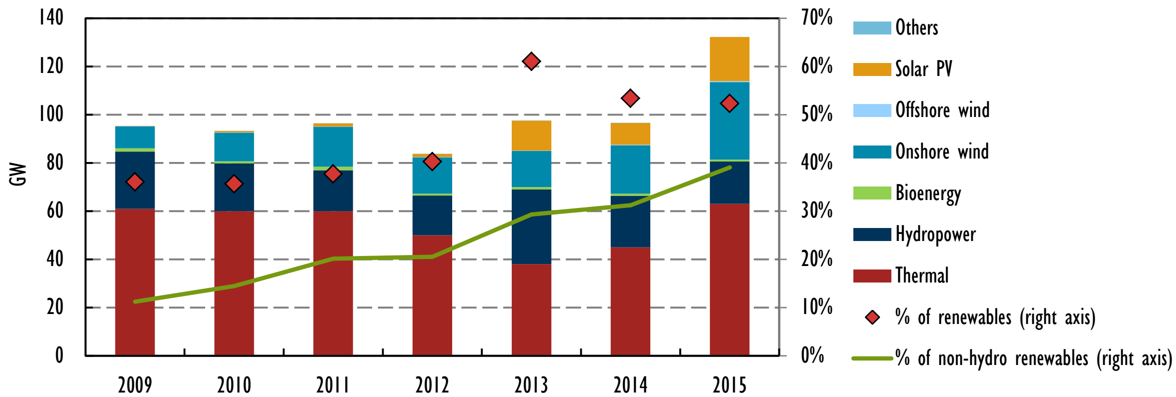
Recent trends

In 2015, China's renewable power generation increased by around 8%, while electricity from coal fell slightly by just over 2%. In addition, the output from non-hydro renewables expanded by 21% year-on-year (y-o-y) as solar and wind capacity installed in 2014 had a full year of production. Overall, renewables represented 24.5% of China's electricity generation.

In 2015, China's power generation grew by only 0.5% and reached over 5 700 TWh, the lowest growth since 1998, while the country's gross domestic product (GDP) expanded by 6.9%. However, power demand picked up slowly and grew by 2.7% in the first half of 2016. This relatively slow growth signals that the relationship between power demand and economic growth has weakened. However, the continuation of this trend will depend on the planned transformation of the Chinese economy from heavy manufacturing industry to services, further implementation of energy efficiency measures, and the rate of electrification of the transport sector among others over the medium to long term.

In 2015, renewables represented over 50% of net additions to power capacity (Figure 1.11). The share of renewables in new electrical-capacity additions was highest in 2013, with record-level hydropower deployment (31 GW) and lower-than-usual new thermal capacity coming on line. However, thermal capacity additions started to increase again, reaching close to 65 GW in 2015. According to the preliminary data of plants under construction, China's thermal additions in 2016 are likely to be over 40 GW. Despite large new capacity additions, China's thermal power generation decreased by over 2% in 2015. This is mainly due to lower demand growth and increasing generation from renewables. In April 2016, the National Energy Administration (NEA) ordered 13 provinces to suspend the approvals of new coal-fired capacity by 2018 and 15 other provinces to delay the construction of already-approved plants.

Figure 1.11 China net capacity additions to power capacity (2009-15)



China's hydropower output increased by an estimated 5% in 2015, due to a full year of production from the capacity (+24 GW) that became operational in 2014 and new additions (+15 GW) in 2015. Although conventional hydropower projects dominated the newly installed capacity, around 1 GW of pumped-storage plants (PSPs) were also commissioned. In China, PSPs are exclusively owned and operated by the State Grid Corporation, as they are considered part of the transmission system. The government announced that it would consider other sources of commercial capital for new investment, but further details had not been released at the time of writing. The government continued to increase approvals for new PSPs, despite the slowdown for new conventional hydropower.

Grid-connected onshore wind capacity increased by over 32 GW in 2015, the highest rate of installations to date, as developers rushed to finish projects before the planned FIT cut in January 2016. In 2015, onshore wind generation increased by 20% and reached close to 185 TWh. However, countrywide full-load hours decreased by 10% y-o-y to 1 728. Overall utilisation rates were 17% lower compared with levels achieved in 2013, due primarily to increasing curtailment levels reaching on average 15% in 2015. Overall, nationwide curtailed generation almost doubled in 2015, after the improvement was observed in both 2013 and 2014. The highest curtailment rates were observed mainly in provinces with large coal-fired capacity installed or were a result of a lack of transmission capacity to dispatch surplus wind power to demand centres. Gansu province led wind curtailment with 39%, followed by Jilin (32%) and Xinjiang (32%). Meanwhile, offshore wind capacity rose by over 55% in 2015, bringing the cumulative total capacity to the 1 GW mark.

In late 2015, the government announced a second downward revision to the onshore wind FIT for new projects; the new tariffs are 4-6% lower depending on the wind site, ranging from 470 Yuan renminbi (CNY) per MWh to CNY 600/MWh (USD 75/MWh to USD 95/MWh). However, projects approved in 2015 that start construction before year-end 2017 are eligible to receive 2015 FIT rates. NEA has announced a further FIT revision to take effect in 2018: tariffs will decrease by another 4-9%, ranging from CNY 440/MWh to CNY 580/MWh (USD 67/MWh to USD 91/MWh).

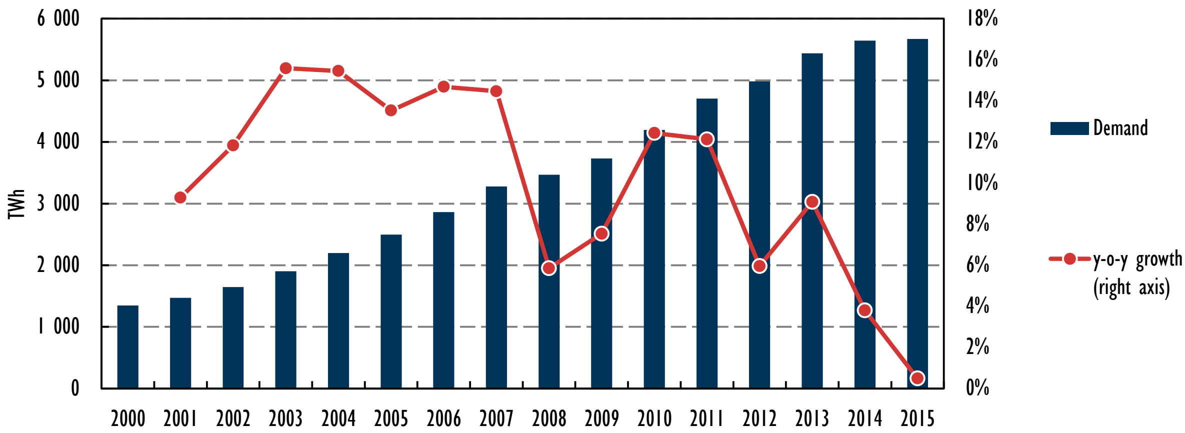
China connected over 15 GW of solar PV capacity in 2015. Overall cumulative capacity reached over 43 GW, of which more than 90% was from utility-scale projects. Annual additions from distributed generation reached close to 2 GW, significantly lower than the NEA's target of 8 GW set in January 2014. In 2015, solar PV generation increased by 34% and reached almost 40 TWh, despite the average nationwide curtailment, which is estimated at 8-10%. FITs for solar PV were also revised down by 2-11% depending on the resource level, ranging from CNY 800/MWh to CNY 980/MWh (USD 120/MWh-USD 150/MWh). FITs in locations with low solar resources (also where power demand is higher) saw the lowest reduction, while for high-resource areas the cuts were steeper. The government aims to promote more deployment in demand centres in order to tackle curtailment challenges. In order not to be affected by the FIT reductions, developers rushed to complete their projects by mid-2016 which resulted in a record-level of 22 GW installed by July. New capacity additions are expected to slow in the second half of 2016 reaching a total of 27 GW by the end of the year.

Medium-term forecast: Main case summary

China's "new normal" economic paradigm will have an impact on both the quantity and quality of energy produced and consumed, but overcapacity in the electricity market has emerged as a challenge. During the last decade, China's double-digit electricity demand growth has been met primarily by coal generation, which has quadrupled since 2000. This growth has been the main driver of higher pollution levels in China's major cities. In March 2016, the government adopted a 13th FYP for the economy, also referred to as the "new normal", which aims for annual GDP growth of 6.5-7% during 2016-20**,** lower than the average growth of 8.5% during 2011-15. The plan aims to focus on shifting economic growth away from heavy industries such as coal, steel and mining towards innovation and services. It also sets protection of the environment as a priority, with a focus on the quality of energy produced to bring down pollution levels. The "new normal" insists also on more efficient production and consumption of energy as a way of reducing carbon emissions and local air pollution.

Accordingly, it is anticipated that China's annual average electricity generation growth could settle around 3.5% over the medium term, lower than the 11% average observed between 2000 and 2011 (Figure 1.12). Renewables are expected to play a larger role, especially in increasing clean electricity generation and meeting additional energy needs over the medium term. However, a new challenge of electricity market overcapacity is expected to emerge as China still has a large pipeline of coal, nuclear and renewable plants under development despite the demand growth having slowed down. Over the medium term, this overcapacity situation is expected to have an impact not only on the grid integration of renewables but also on financial health of thermal assets, which are expected to operate fewer hours than planned.

Figure 1.12 China's electricity demand growth (2000-15)



Source: IEA (2016b), *World Energy Statistics and Balances 2016* (database), www.iea.org/statistics.

The government proposed more ambitious renewable energy goals under the 13th FYP after exceeding most of its previous targets by 2015 (Table 1.4). The country's 12th FYP, which covered the 2011-15 period, achieved the majority of targets, especially those related to energy and carbon intensity, which were exceeded. Under the 12th plan, China also announced indicative renewable energy targets to 2015, which were revised under China's Strategic Plan for Energy Development 2014-20 issued by the State Council in November 2014. These targets have been important drivers for renewable deployment, together with economic incentives (mainly FITs). Overall, China exceeded its targets for renewable energy by 50 GW at the end of 2015, thanks to faster deployment of hydropower, onshore wind and solar PV, while the country fell short of its goals for offshore wind, CSP, bioenergy and geothermal. In March 2016, the government adopted the 13th FYP for the economy. Although final renewable energy targets by 2020 were not officially published at the time of writing of this report, the latest drafts indicate more ambitious indicative targets for solar PV and onshore wind. It is expected that China's renewable energy goals will remain an important driver for deployment over the medium term.

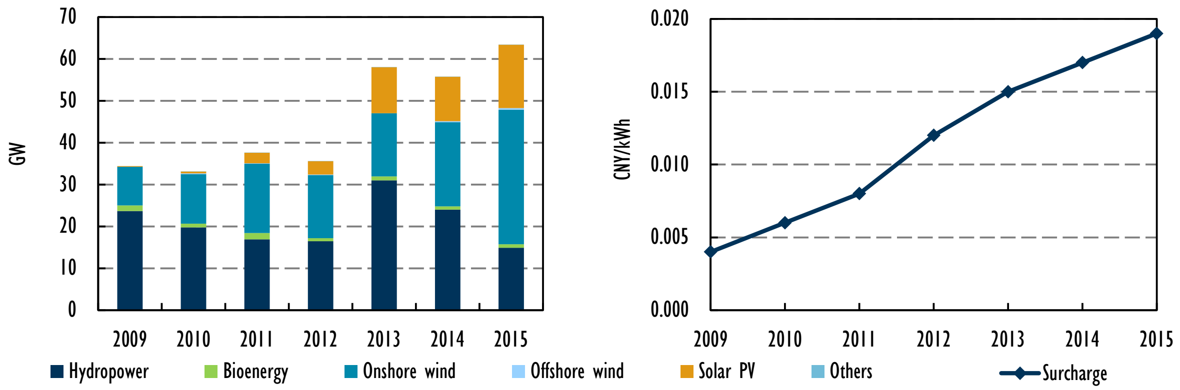
China seeks a financially sustainable policy to tackle the increasing total cost of renewable support. The country installed over 160 GW of non-hydro renewables since 2010 mostly supported by the FIT, which was introduced in July 2009. This rapid growth also increased the financial burden, with the renewable energy surcharge more than tripling over the last five years (Figure 1.13). During the last 12 months, the government revised down the FITs for both solar PV and onshore wind in order to reflect reductions in technology costs. China now plans to move away from FITs to a more market-based incentive scheme and to promote the deployment of renewables closer to demand centres in order to curb high levels of curtailment. In March 2016, the NEA released Guiding Opinions on Establishing Renewable Energy Portfolio Standards, which set goals for renewable energy consumption for each province from non-hydro renewables by 2020 in order to reach the countrywide 9% target. The government is also considering a national tradable green certificate system that would support provinces (especially those with high coal-fired generation) to meet their renewable energy consumption targets. This market-based policy is in line with China's goal to start a nationwide carbon market by 2017, which is currently operational in seven provinces. In addition, the government is also looking into competitive auction systems to identify support levels for the long-term remuneration of solar PV. Overall, several policy options are on the table to decrease the cost of renewable support, but they are all at an early stage of development. It is expected that concrete steps will be taken over the medium term, but the FIT should continue to remain a strong driver during the transition; retroactive policy change is not anticipated.

Table 1.4 China renewable energy targets and achievements under the 12th FYP and proposed targets under the 13th FYP

GW	12th FYP 2011-15, targets by 2015	2015 achievements	China strategic energy plan in 2014, targets by 2020	13th FYP 2016-20 proposal, targets by 2020
Hydropower	290 GW	320 GW	420 GW	330 GW (excluding PSP)
Onshore wind	100 GW	128 GW	200 GW	250 GW
Offshore wind	5 GW	1 GW	30 GW	N/A
Solar PV	34 GW	43 GW	100 GW	150 GW
CSP/STE	1 GW	0.02 GW	3 GW	10 GW
Bioenergy	13 GW	10.3 GW	30 GW	15 GW
Geothermal	0.1 GW	0.03 GW	0.1 GW	N/A

Note: Unless otherwise mentioned, hydropower targets include both conventional and PSP capacity.

Figure 1.13 China net renewable power capacity additions and renewable energy surcharge



Solar PV and onshore wind are expected to remain economically attractive even with revised FIT levels that aim at promoting deployment closer to demand centres. For onshore wind, China has one of the lowest system costs and strong financing environment. LCOEs for typical projects estimated between USD 60/MWh and USD 85/MWh remain economically attractive versus the revised FIT level of USD 67/MWh to USD 91/MWh. The revised FIT scheme incentivises more deployment in medium- and low-wind-speed areas closer to demand centres where curtailment rates are lower. Recently, more projects have received permits in these areas, indicating further deployment over the medium term.

For solar PV, costs continue to fall, with investment costs in China among the lowest globally. The LCOE of typical utility-scale projects is estimated at USD 80/MWh to USD 105/MWh, which remains attractive even under the revised FIT of USD 120/MWh to USD 150/MWh. With these tariffs, utility-scale projects should continue to drive the deployment over the medium term, with new installations expected to move closer to demand centres. For commercial and industrial applications, the financing remains a significant barrier, with banks concerned about the creditworthiness of some project owners (or the off-taker in the case of third-party ownership) and potential asset recovery issues. For residential projects, retail rates remain low, and the availability of credits to finance small-scale projects is still a challenge. In addition to technology-specific barriers, many renewable projects under FITs have suffered from late payments, especially since 2014.

Despite improvements in the connection rate of renewable plants, nationwide annual average curtailment of wind increased to 15% and solar power curtailment grew to 10%. High levels of curtailment have a direct impact on the revenue stream of renewable plants. A relatively high FIT has been compensating for the loss of revenue due to curtailment for the majority of wind and solar projects. However, with decreasing tariffs for new projects, margins are expected to be tighter, especially in areas where curtailment is highest. In March 2016, the government announced new policies to decrease curtailment and reiterated utilities' obligation to purchase all renewable electricity generated, as well as priority dispatch rules. The government document also called for a guaranteed purchase scheme in which curtailed generation will be compensated either by the conventional generators or grid companies, depending on the reason of the curtailment. The NEA is expected to release a document to define annual required operational hours for renewables in northern provinces where curtailment remains high. However, uncertainty remains over the implementation of this new policy. It is important to note that there is still a significant number of licensed renewable projects under construction in the north, which might further increase the integration challenge.

Table 1.5 China main drivers and challenges to renewable energy deployment

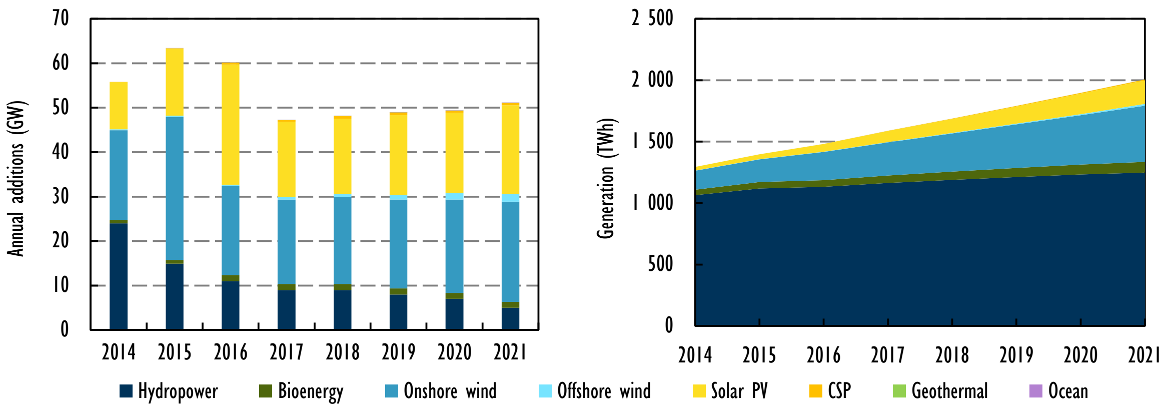
Drivers	Challenges
Strong government policy backing power sector reforms	Increasing cost of renewable subsidies and expected policy changes
Ambitious long-term renewable targets backed by FITs	Administrative barriers and financing challenges to the deployment of distributed PV
Ample availability of low-cost financing	Grid integration and upgrades on both the transmission and distribution infrastructure

Despite curtailment challenges, overall China's forecast is more optimistic versus *MTRMR 2015*, mainly driven by more ambitious preliminary targets and air pollution concerns**.** China's renewable capacity is expected to grow by 305 GW over the medium term, to reach 807 GW in 2021. Onshore wind is forecast to lead the growth with 122 GW over 2015-21. After record-level installations in 2015, grid-connected annual additions are expected to stabilise at 20 GW to 24 GW over the medium term. While the grid connection rate is expected to further improve, curtailment will remain challenging, affecting the economics of some plants under the new FIT regime. Solar PV is anticipated to expand by 117 GW, the majority of the additions expected to come from utility-scale projects, with distributed-scale installations picking up in the second half of the forecast period as further policy actions to tackle financing and legal challenges are anticipated.

The hydropower forecast is revised down due primarily to increasing social costs associated with large-scale conventional projects. Over the medium term, annual hydropower additions are expected to slow from over 30 GW in 2013 to about 5 GW in 2021, with some growth anticipated to come from pumped-hydro storage projects. The offshore wind forecast is more optimistic with 7 GW expected to be on line by 2021, well below its 30 GW target by 2020. Despite the ambitious target, the CSP project pipeline remains small, and deployment faces challenges concerning high up-front costs and lack of incentives to value storage generation. Bioenergy faces challenges to scaling feedstock supply chains; most future development is likely to occur in municipal solid waste for power, driven by rapid urbanisation.

China's renewable power generation is expected to increase from 1 397 TWh in 2015 to 2 006 TWh in 2021 (Figure 1.14). With this generation growth, renewables are seen meeting over 40% of incremental demand growth over the medium term. Wind should provide a quarter of this growth, while hydropower and solar PV are expected to contribute 21% and 25% respectively. The rest should come from bioenergy and CSP. The share of renewables in China's overall electricity generation is expected to reach over 28% in 2021, a 5-percentage-point increase from 2014.

Figure 1.14 China net renewable capacity additions and generation (2014-21)



Source: Historical generation from IEA (2016b), *World Energy Statistics and Balances 2016* (database), www.iea.org/statistics.

Medium-term forecast: China accelerated case summary

Given the current energy policy transition and integration challenges, it is difficult to quantify China's accelerated case. Overall, renewable capacity growth could be 26% higher, with further upward potential on generation (Table 1.6). Clearer implementation of power sector reforms and integration measures to alleviate grid congestion, as well as enforcement of regulations to prioritise the uptake of renewables by grid companies, would be supportive, especially for onshore wind.

The increase for solar PV is significant (+29 GW in 2021) and expected to come from distributed generation if legal, administrative and financing challenges are addressed. Distributed generation could expand faster, especially in locations closer to demand centres, contributing to new generation needs. Offshore wind capacity could be just over 3 GW higher in 2021, if regulatory and administrative challenges concerning grid connection and licensing are tackled. The increase for CSP would depend on a remuneration framework based on the time of generation, which would improve the technology's economics. Hydropower would require an acceleration of environmental approvals and the financial close of planned projects in the pipeline. Finally, more encouragement of decentralised generation could help bioenergy, mainly through more small-scale biogas and waste-to-energy installations.

Table 1.6 China renewable electricity capacity projection (GW), main and accelerated case

	2015	2016	2017	2018	2019	2020	2021	2021 Accelerated
Hydropower	319.4	330.4	339.4	348.4	356.4	363.4	368.4	384.9
Bioenergy	10.3	11.7	13.0	14.4	15.7	17.1	18.4	25.9
Wind	129.3	149.7	169.2	189.4	210.4	232.9	257.1	281.0
Onshore	128.3	148.3	167.3	186.8	206.8	227.8	250.3	271.0
Offshore	1.0	1.4	1.9	2.6	3.6	5.1	6.8	10.0
Solar PV	43.2	70.2	87.2	104.2	122.2	140.2	160.2	189.0
CSP/STE	0.0	0.5	0.9	1.5	2.1	2.6	3.1	5.1
Geothermal	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1
Ocean	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**502.3**	**562.4**	**609.7**	**657.8**	**706.8**	**756.2**	**807.3**	**886.0**

Note: For further country-level forecasts, see online Excel workbook that accompanies this report at www.iea.org/publications/mtrmr/. Rounding may cause non-zero data to appear as "0.0" or "- 0.0". Actual zero-digit data is denoted as "-".

North America

Recent trends

North America added almost 23 GW of new renewable capacity in 2015, 40% higher than in 2014. Total renewable power output remained stable at 1 043 TWh and represented around 20% of total electricity generation in the region, with the United States and Canada dominating overall statistics.

In the **United States**, renewables dominated power capacity installations with over 16.5 GW coming on line, representing 65% of overall capacity additions, while new natural gas capacity was around 4 GW in 2015. Backed by the PTC, annual onshore wind annual deployment was 76% higher versus 2014 and grew 8.6 GW, with Texas (1.3 GW), Oklahoma (0.85 GW), Kansas (0.6 GW) and Iowa (0.5 GW) leading deployment (AWEA, 2016). In Texas, some wind projects came on line without long-term PPAs, selling electricity to the Electric Reliability Council of Texas (ERCOT) on a merchant basis. In addition, large-scale wind projects that signed power purchase contracts (around 3 GW) with corporations such as IKEA, Microsoft and Google also came on line last year. In 2015, wind generation increased by 5%, representing close to 5% of electricity generation in the United States.

Backed by federal ITC and state-level incentives, solar PV additions grew by over 7.3 GW from 2014 and reached over 26 GW by 2015 making it the third-largest annual market globally. Overall, solar PV electricity generation increased by 10%, with its share in overall power output remaining less than 1% in 2015. California led the new additions, representing about 45% of the market in 2015, followed by North Carolina (16%), Nevada (6%); Massachusetts (4%) and New York (3%) (SEIA/GTM Research, 2016). As of March 2016, California represented around half of the cumulative solar PV capacity in the United States.

In 2015, utility-scale projects continued to dominate the solar PV market, representing 55% of new additions. However, their share decreased slightly, with residential PV installations being the fastest-growing segment, representing 30% of new additions, the highest since 2010, mainly due to declining costs, new financial products, and wider geographic distribution of projects under solar lease and third-party-ownership models. The growth in commercial solar PV applications remained stable in 2015. Meanwhile, debates over electricity rate design and net metering policies have intensified in response to the growing distributed solar PV market. In Nevada, the Public Utilities Commission approved an increase of the monthly fixed charge, decreased volumetric charges and reduced the remuneration for excess electricity by replacing retail rates with the wholesale market price retroactively. Hawaii decided to replace its net metering programme. Customers there with solar PV installations are required to either sell all electricity to the grid at wholesale electricity prices, or self-consume all the power they produce, in exchange for preferential permitting treatment. In addition, at the time of writing of this report there is pending legislation in Arizona, Ohio, Louisiana and Illinois concerning the modification of net metering rules.

Bioenergy additions were well behind solar and wind, with around 300 MW of capacity coming on line in 2015. For CSP, only the Crescent Dunes project (110 MW) with ten-hour storage became operational. In 2015, CSP additions were lower compared to over 300 MW commissioned in 2014. Electricity generation from hydropower decreased for the fourth year in a row due to continued drought conditions in some important hydropower basins, with only 150 MW of new capacity becoming operational. Overall, it represented around 6% of generation in 2015. Newly installed geothermal capacity picked up slightly with 70 MW installed, mostly in Nevada.

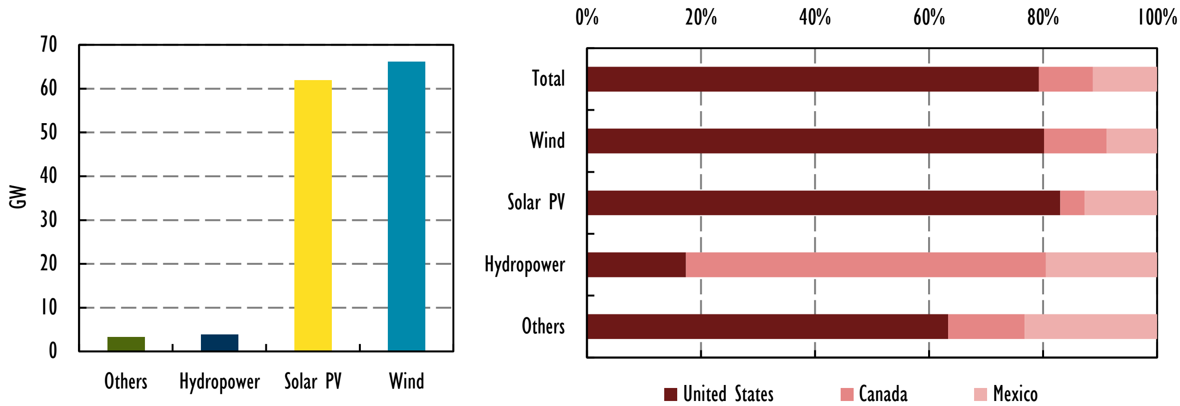
In **Canada,** renewable capacity expanded by 5.1 GW in 2015. Hydropower provided close to half of renewable additions and remains the largest source of electricity generation. In 2015, annual additions from onshore wind decreased by 20% to 1.5 GW, with 60% of new installations located in Ontario, followed by Quebec (22%). New additions in Nova Scotia picked up with the commissioning of the South Canoe Wind Farm (102 MW) and smaller plants. Alberta and Saskatchewan contributed as well. For solar PV, almost all additions in 2015 came from Ontario, driven by the FIT programme for small systems and public procurement for utility-scale projects. Overall, solar PV and onshore wind together represented only 5% of electricity generation. In addition, the biomass conversion of the Thunder Bay coal power plant (306 MW) in Ontario was completed in October 2015, increasing the country's cumulative bioenergy capacity to 2.3 GW.

Mexico's new renewable additions were just over 1 GW in 2015, but were 29% lower y-o-y. Onshore wind represented 70% of these installations, with the commissioning of projects that signed long-term contracts with the government utility, Comision Federal de Electricidad (CFE) before the national energy reform. Although there were no projects connected to the grid in 2015, hydropower remains the largest source of renewable electricity generation, with its share in total power output standing at 10%. Solar PV and geothermal additions were small, with solar PV growing by around 100 MW and geothermal by 50 MW. In 2015, the share of renewables in overall electricity generation decreased slightly due to a 20% fall in hydropower output versus 2014.

Medium-term outlook: Regional main case summary

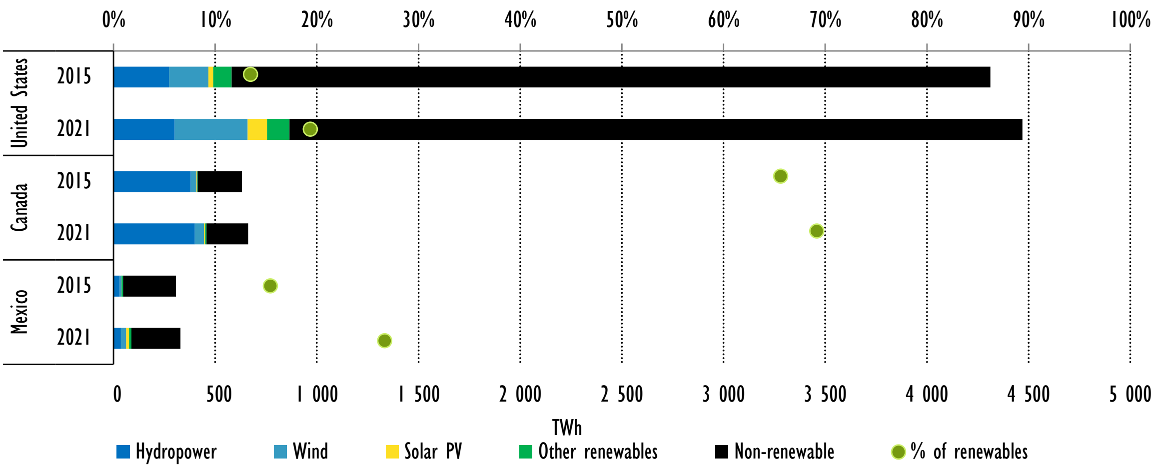
In North America, recent policy and regulatory developments have led to a more optimistic outlook for renewables. The long-term extension of tax credits in the United States, the successful implementation of energy auctions in Mexico, and the improvements in provincial renewable energy policies in Canada are all expected to result in higher renewable deployment compared with the forecast presented in *MTRMR 2015*. Accordingly, the cumulative capacity of the region is expected to be 48 GW higher in 2020 than in *MTRMR 2015*. Renewable capacity in North America is anticipated to expand by 135 GW over 2015-21. The United States is likely to represent about 80% of this growth (107 GW), followed by Mexico (15 GW) and Canada (13 GW), which remain strong markets (Figure 1.15).

Figure 1.15 North America net renewable capacity additions by technology and country (2015-21)



Solar PV and wind are likely to represent a significant majority of the growth over the medium term. Solar PV is expected to grow by 62 GW, with the majority of new net additions to power capacity coming from the United States. Onshore wind expansion is forecast to expand by 65.5 GW, followed by hydropower (4 GW) and bioenergy (2 GW).

Figure 1.16 North America electricity generation by source and share of renewables in 2015 and 2021



Source: Total electricity generation estimates are from IEA (forthcoming), *World Energy Outlook 2016*.

In the **United States**, renewable generation is forecast to increase by 285 TWh over the medium term, with the share of renewables in total generation set to increase from below 14% in 2015 to over 19% in 2021 with onshore wind leading the generation (Figure 1.16). The forecast improved significantly compared with *MTRMR 2015,* mainly due to the long-term extension and planned phase-out of federal tax incentives for wind and solar, which is expected to give long-term visibility to developers. US renewable capacity should grow by 107 GW over the forecast period, reaching more than 328 GW in 2021. Overall, renewable additions are expected to be 40 GW higher in 2020 than the forecast presented in *MTRMR 2015.* The details of the US forecast are discussed in the dashboard that follows this section.

In **Mexico,** renewable capacity is forecast to almost double over the medium term, with 15 GW of new capacity coming on line, mostly driven by tenders for energy and clean certificates. Solar PV and onshore wind are likely to dominate the growth. The forecast is more optimistic than *MTRMR 2015*, primarily due to the clarification of rules and regulations governing electricity and green certificate markets, which were the major source of uncertainty for the deployment of renewables. The share of renewables in generation is expected to be stable in the first half of the forecast, but it is expected to increase significantly after 2017-18 with the commissioning of wind and solar projects that won the first auction in 2016. By 2021, the share of renewables in electricity generation should reach 24%. With this projected growth, renewables are expected to represent the majority of Mexico's generation needs by that time. The details of the Mexico forecast are also discussed in the dashboard that follows this section.

Canada's renewable capacity is expected to grow by around 13 GW over 2015-21, led by onshore wind (+7 GW) and solar PV (+2.7 GW), driven by strong provincial-level support particularly in Ontario, Quebec and Alberta (Table 1.7). Although hydropower is expected to remain an important source of electricity generation, its growth slows down with only 2.4 GW coming on line over the medium term, roughly half of the growth recorded over 2009-15. The forecast was mainly improved for onshore wind, solar PV and bioenergy due to provincial-level policy improvements, especially in Alberta (Box 1.2).

Table 1.7 North America net renewable capacity additions and % in generation in 2014 and 2015

North America		Net capacity additions (GW)					% of electricity generation				
Country	Year	Hydropower	Wind	Solar PV	Other renewables	Total	Hydropower	Wind	Solar PV	Other renewables	Total
United States	2014	0.6	4.9	6.2	0.5	12.2	6%	4%	1%	2%	13%
	2015	0.1	8.6	7.3	0.5	16.5	6%	4%	1%	2%	13%
Canada	2014	0.0	1.9	0.6	0.0	2.5	58%	3%	0%	1%	63%
	2015	2.3	1.5	0.6	0.7	5.1	60%	5%	0%	1%	66%
Mexico	2014	0.8	0.4	0.1	0.1	1.4	13%	2%	0%	2%	18%
	2015	0.0	0.7	0.1	0.2	1.0	10%	3%	0%	2%	15%

Note: Rounding may cause non-zero data to appear as "0.0" or "- 0.0". Actual zero-digit data is denoted as "-".

Sources: 2014 capacity data for OECD countries based on IEA (2016a), *Renewables Information 2016*, www.iea.org/statistics/. All other capacity data from multiple sources; see Chapter 2 technology sources for more detail. Generation data based on IEA (2016b), *World Energy Statistics and Balances 2016*, www.iea.org/statistics/.

Box 1.2 Recent climate policy developments in Alberta

In November 2015, the government of Alberta announced a Climate Leadership Plan and its goal for zero emissions from coal-fired plants by 2030; they currently produce over 50% of the province's electricity. Alberta aims at replacing its coal-fired generation primarily with renewable generation. In addition to current regulations, under which more than 1 GW of coal power should decommission by 2019, Alberta decided to increase its carbon tax from 10 Canadian dollars (CAD) per tonne to CAD 20 per tonne from January 2017, and CAD 30 per tonne from January 2018. This increase may potentially affect the economics of some coal plants and result in the early commissioning of several projects. In addition, Alberta will open a tender to procure large-scale solar and wind power by the end of 2016. The provincial government expects to replace over 4 GW of coal capacity with renewables by 2030.

For onshore wind, Ontario, Quebec and Alberta are expected to drive the deployment in Canada supported by tenders, with British Columbia and Nova Scotia also contributing with smaller additions:

- In March 2016, Ontario's latest procurement programme contracted five wind projects, with a weighted average price of CAD 85/MWh (USD 65/MWh). The lowest winning bid was CAD 65/MWh (USD 49/MWh), which was around 35% lower than the province's previous FIT levels for wind. The province awarded 300 MW of wind projects with its first procurement round, while the second round aims to contract 600 MW by the end of 2016.
- Quebec's new long-term energy plan is expected to announce further wind procurement, the details of which were not available at the time of the writing of this report.
- The outlook in Alberta is more positive following the announcement of the tender and the increasing carbon price. The majority of wind projects are currently operating as merchant plants with limited revenue certainty. The tender with long-term contracts is expected to increase the bankability of new projects, also resulting in lower cost of capital. Deployment is expected to pick up during the second half of the forecast, depending on the tender schedule.

Table 1.8 North America cumulative renewable energy capacity in 2015 and 2021

Total capacity (GW)	2015				2021			
	North America	Canada	Mexico	United States	North America	Canada	Mexico	United States
Hydropower	192.6	77.8	12.5	102.3	196.5	80.3	13.2	103.0
Bioenergy	17.0	2.3	0.8	13.8	19.1	2.8	1.1	15.3
Onshore wind	87.9	11.2	3.3	73.4	153.4	18.5	9.1	125.9
Offshore wind	-	-	-	-	0.6	0.1	-	0.5
Solar PV	28.8	2.4	0.3	26.1	90.7	5.1	8.1	77.5
CSP/STE	1.8	-	-	1.8	2.1	-	-	2.1
Geothermal	4.5	-	0.9	3.6	5.1	-	1.2	3.8
Ocean	0.0	0.0	-	0.0	0.0	0.0	-	0.0
Total	**332.6**	**93.8**	**17.7**	**221.1**	**467.7**	**106.7**	**32.9**	**328.2**

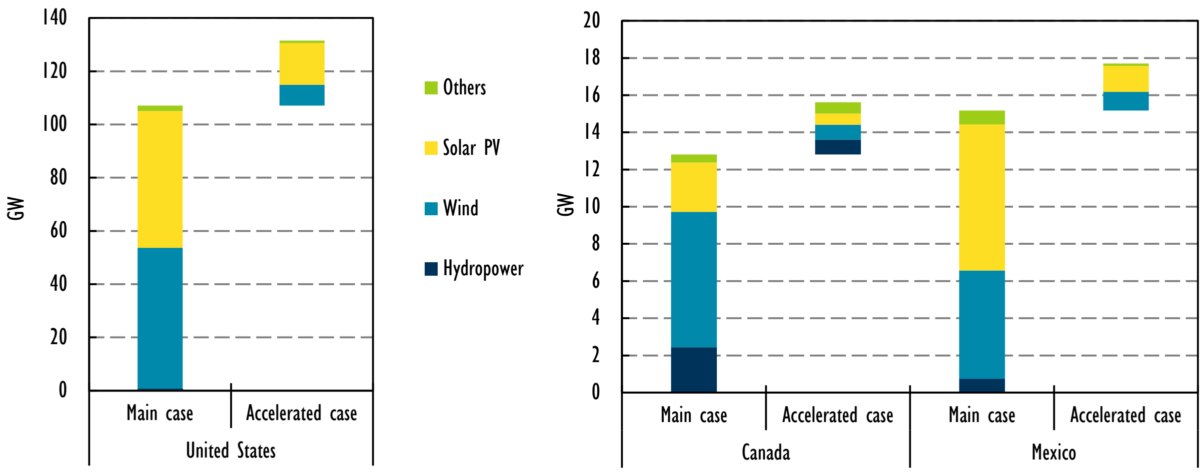
Notes: For further country-level forecasts, see online Excel workbook that accompanies this report at www.iea.org/publications/mtrmr/. Rounding may cause non-zero data to appear as "0.0" or "- 0.0". Actual zero-digit data is denoted as "-".

Canada's solar PV capacity should expand by 2.7 GW, reaching over 5 GW by 2021 due to generous FITs for residential and commercial applications in Ontario (ranging from CAD 275/MWh (USD 210/MWh) to CAD 385/MWh (USD 290/MWh), depending on the size of applications) and small utility-scale additions expected from the Large-Scale Renewable Procurement. In addition to Ontario and Quebec, Alberta also is also anticipated to contribute with utility-scale projects after 2018-19 from its new tender scheme. In addition, bioenergy capacity is expected to increase by 430 MW over the medium term.

Medium-term outlook: Regional accelerated case summary

Overall, cumulative renewable capacity in North America could be 23% higher in 2021, with onshore wind and solar PV leading the accelerated case (Figure 1.17). In the **United States**, renewable capacity additions over the medium term could be 24.3 GW higher, mainly depending on the pace of commissioning of projects before the phase-out of federal tax incentives. The accelerated case for the United States also assumes that more solar PV and wind capacity could be installed in states with limited renewable energy deployment and high carbon dioxide (CO_2) reduction targets that take advantage of early credits under the CPP. In **Mexico**, renewable growth could be 30% higher compared to the main case. This accelerated case assumes that all auctioned plants are commissioned and connected to the grid on time over the forecast period. A faster uptake of distributed solar PV could also contribute to Mexico's accelerated deployment. The details of the accelerated cases for the United States and Mexico can be found in the following dashboards.

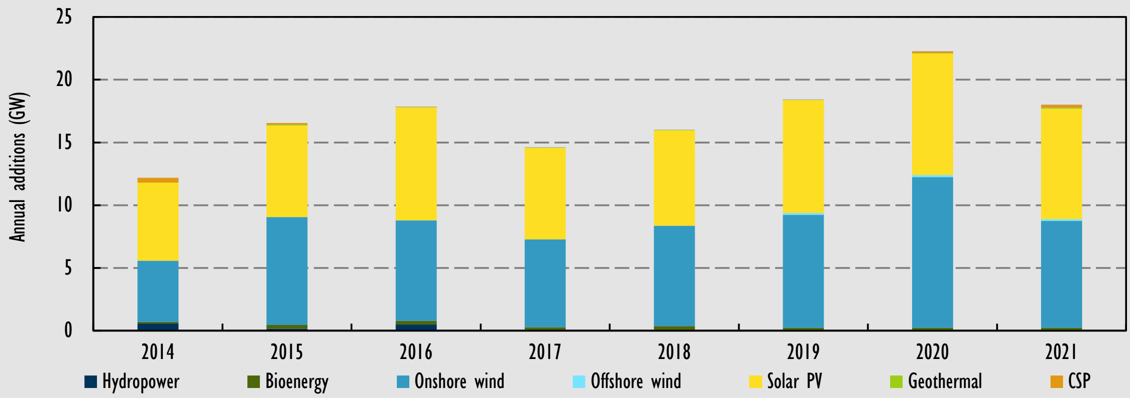
Figure 1.17 North America renewable capacity additions (2015-21), main versus accelerated case



In **Canada**, the baseline forecast assumes no major policy changes at the federal level concerning renewable incentives. Some provincial-level policy and market enhancements could result in stronger renewable energy deployment, especially for onshore wind. Alberta's accelerated case assumes that the province's current climate change policy is fully implemented, requiring a complete coal phase-out by 2020 and the replacement of this retiring capacity with renewables. As Alberta's wind potential remains untapped, the accelerated case assumes faster decommissioning of some coal plants for economic reasons with an increasing carbon price, combined with faster deployment of onshore wind and solar PV. Under these conditions, total cumulative onshore wind capacity could potentially be 2 GW higher in 2021, and solar PV capacity could be 0.6 GW higher. Hydropower capacity could increase by 0.8 GW with faster-than-expected commissioning of large plants under construction. In addition, biomass capacity could be 0.6 GW higher, taking into account the potential for coal-to-biomass conversion, especially in Alberta.

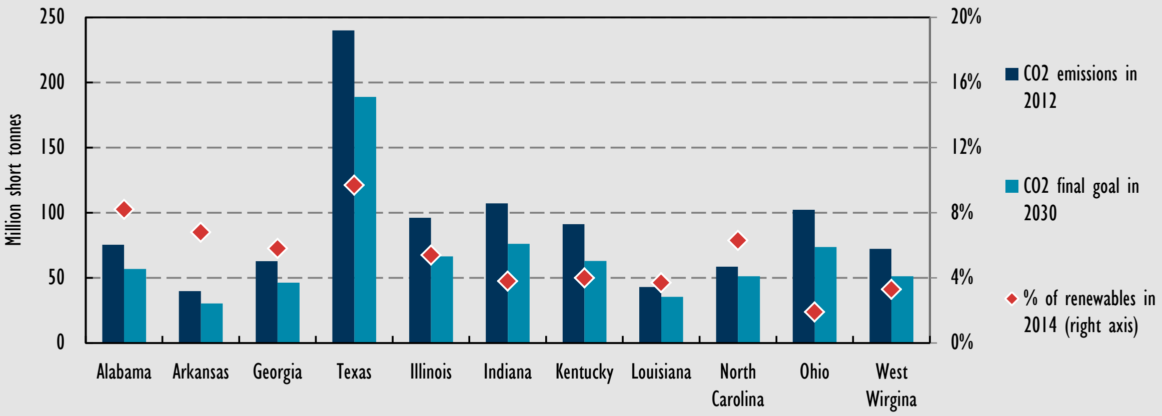
United States dashboard

Figure D.13 US annual net additions to renewable capacity by technology (2014-21)



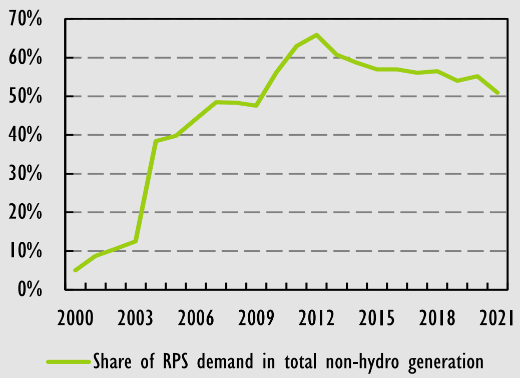
Source: Historical OECD capacity derived from IEA (2016a), *Renewables Information 2016, www.iea.org/statistics/.*

Figure D.14 CPP mass-based goal calculation and % of renewables in selected states



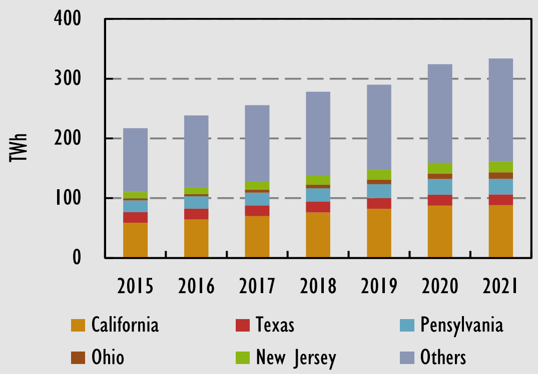
Source: US EPA (2015), Proposed Federal Plan for Clean Power Plan.

Figure D.15 US share of RPS demand in total non-hydropower renewable generation



Sources: Analysis based on LBNL (2016a), *RPS Demand Projections.*

Figure D.16 US RPS generation growth (2015-21)



Source: LBNL (2016b), *U.S. Renewables Portfolio Standards: 2016 Annual Status Report.*

Medium-term forecast: United States main case

US renewable capacity should expand by 107 GW over 2015-21. The forecast has been revised up significantly, by over 40 GW in 2020 compared with *MTRMR 2015*, due to multi-year extension of federal tax incentives. Solar PV and onshore wind are expected to benefit the most from this extension. Together they represent over 90% of total renewable additions over the medium term. RPS and other state-level schemes should continue to support the deployment for both utility- and small-scale projects.

The CPP, which would introduce CO2 emissions standards for power plants but is currently under legal challenge, is expected to have a limited impact on renewable deployment over 2016-21. The combination of federal tax incentives and state-level policies are stronger drivers. In August 2015, the Environmental Protection Agency finalised the guidelines and proposed two approaches for states to comply with state-specific emissions rate limits: mass-based and rate-based. The mass-based approach provides early credits for states that deploy renewables in 2020-21 before the CPP obligation starts in 2022. These credits could be an additional driver for states with high emissions reduction requirements, a low share of renewable generation and limited state-level incentives. However, it is difficult to translate states' approaches into actual renewable deployment, as this will depend on whether they would prefer early credits, their technology choice (between renewables and energy efficiency) and how much capacity they can actually deploy prior to 2022.

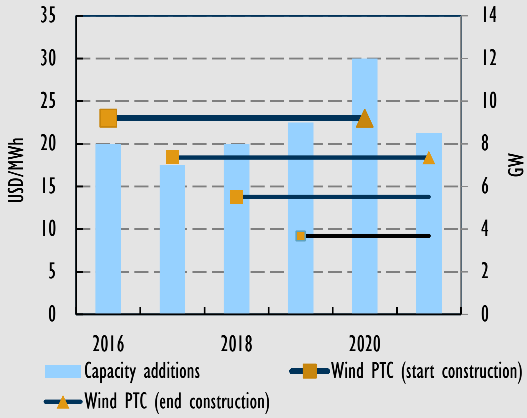
RPS policies have been an important driver for renewable expansion, but their role in both generation and capacity growth are expected to decrease over the medium term. Since 2000, RPS programmes have been responsible for around 60% of non-hydro renewable electricity growth, with wind leading the RPS-related additions (36 GW), followed by solar PV (17 GW), biomass (3 GW) and geothermal (0.5 GW). Almost all states were on track to meet their interim RPS targets (LBNL, 2016b). Over 2016-21, new RPS demand will be driven mainly by California, representing around 30% of the growth, with its revised RPS target of 50% by 2030. The demand in Texas is expected to be flat as the state is ahead of schedule. Ohio, New Jersey, Illinois and Pennsylvania are also important contributors, though policy uncertainties in Ohio and Illinois pose challenges. Since 2013, the share of RPS demand in non-hydro renewable generation has started to decrease, due to a rise in corporate PPAs and long-term hedge contracts, especially for large wind farms in Texas and the Midwest and solar PV projects in California. Over the medium term, this trend is expected to continue with improving competitiveness of renewables in addition to federal tax incentives.

The multi-year extension and planned phase-out of the ITC and the PTC have lifted a major policy uncertainty over the deployment of solar PV and onshore wind. Federal tax incentives remain the most important driver for renewable deployment, especially over 2015-21. In December 2015, the PTC for onshore wind was extended through the end of 2019, but will be progressively reduced from 2017 to USD 18/MWh, and then again from 2019 to USD 9/MWh. However, according to new Internal Revenue Service (IRS) rules, projects that qualify for a PTC have four years to complete their construction. For other renewable energy technologies (geothermal and biomass), the PTC was extended only to the end of 2017. The ITC was extended through to 2022 for utility-scale, commercial and third-party-owned solar PV, but it will gradually decrease in 2020 from 30% to 26%, and to 22% for facilities starting operation in 2021, then dropping to 10%. For host-owned residential systems, the ITC will be phased out through 2021 following the same schedule.

The change in federal tax policy is expected to result in an additional deployment of 52 GW of renewables in the United States over 2015-21 under the main case compared with the MTRMR 2015 forecast. Wind and solar PV alone represent over 90% of this additional growth, but the ITC and PTC phase-out schedule and construction clauses should dictate their annual deployment profiles. For onshore wind, there were 8 GW to 10 GW of projects under construction as of January 2016, with another 3 GW to 5 GW in an advanced development stage.

United States dashboard

Figure D.17 PTC and ITC extension and annual additions for wind and solar PV



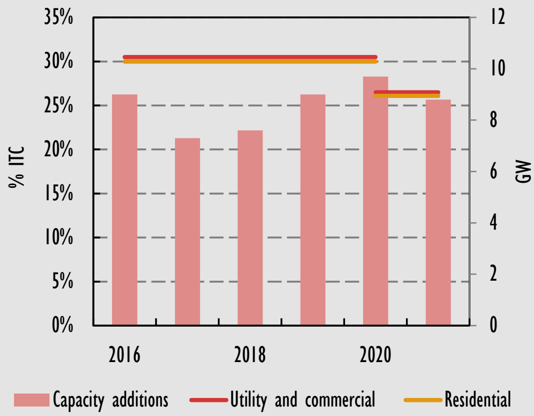


Figure D.18 US solar PV annual net additions by segment

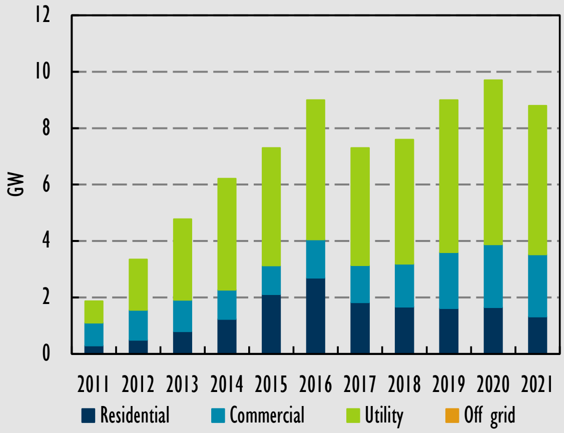


Figure D.19 US solar PV cumulative capacity by segment

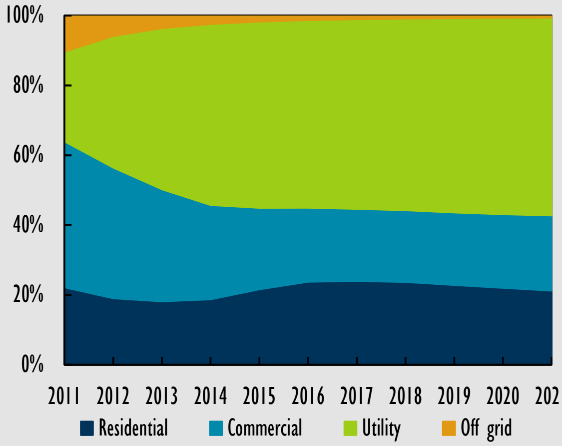


Table D.5 US renewable power capacity

	2015	2017	2019	2021	2021*
Hydropower	102.3	102.8	102.9	103.0	103.0
Bioenergy	13.8	14.4	14.9	15.3	15.9
Onshore wind	73.4	88.4	105.4	125.9	133.7
Offshore wind	-	0.0	0.2	0.5	0.5
Solar PV	26.1	42.4	59.0	77.5	93.2
CSP/STE	1.8	1.8	1.8	2.1	2.1
Geothermal	3.6	3.7	3.7	3.8	4.1
Ocean	0.0	0.0	0.0	0.0	0.0
Total	**221.1**	**253.5**	**287.9**	**328.2**	**352.5**

* Accelerated case. Note: Rounding may cause non-zero data to appear as "0.0" or "- 0.0". Actual zero-digit data is denoted as "-".

• Drivers

- extension of federal tax credits

- state-level RPS with tax incentives

- improving economics of onshore wind and solar with cheaper financing.

• Challenges

- legal challenge over implementation of the CPP

- state-level debates over net energy metering and electricity tariff design

- gas prices expected to remain low.

As a result, the project pipeline is likely to expand fast over 2016-19, with developers required to start construction before the end of 2019 to be eligible for the PTC. With the new construction clause published by the IRS, onshore wind additions should peak in 2020 as developers that are eligible for the full tax credit are expected to commission their projects closer to the “place in service” deadline. In 2021, additions are expected to decrease slightly versus 2020 with the PTC phase-out, but they remain strong as further generation cost reductions are expected to improve the economic attractiveness of new projects. Overall, US wind capacity should expand by 53 GW to reach over 126 GW in 2021.

Solar PV is expected to benefit most from the ITC extension, with utility-scale projects still leading the outlook. In 2016, additions should be higher versus 2015 as there are large utility-scale projects already at an advanced development stage. However, the annual market is expected to be lower in 2017 and then show a growing trend until 2020 as developers need to place their plants in operation to be eligible for the full ITC. Overall, US solar PV deployment is expected to grow by over 50 GW, with utility-scale projects representing around 50% of this growth. While California is still expected to play an important role in US utility solar PV expansion with its increased RPS target, deployment should be more geographically spread out. In 2014-15, utilities, especially in Texas and in the Southwest, signed PPAs ranging from USD 35/MWh to USD 60/MWh, including ITC. While these prices may also include additional state-level incentives and/or special contractual agreements, decreasing generation costs remain an important driver for state utilities to procure solar PV electricity to either meet their RPS demand or replace scheduled retiring capacity.

Despite the extended ITC, utility electricity rate design and net metering policies continue to raise uncertainty over the scale-up of residential and commercial solar PV in several states. In Nevada, the regulator decided to increase fixed charges by 50% and changed excess electricity remuneration from retail to the average wholesale market rate retroactively in December 2015. Consequently, the three largest US installers decided to cease their operations in the state. Arizona and Mississippi introduced similar changes but only for new installations. In Hawaii, the regulator voted to end the state’s net metering scheme in October 2015 and proposed two alternatives to new customers: grid-supply and self-supply. Those changes are expected to slow the deployment of residential PV in these states. In California, the regulator approved a one-time connection fee, a non-by-passable charge on all grid-supplied electricity and a monthly minimum bill. The new residential applications connected in 2018 are required to implement time-of-use rate schedules. In New York, the regulator suspended the net metering cap while the new remuneration scheme for residential projects is being decided upon. Minnesota implements value of solar tariffs (VoST) that provide specific rates to excess solar generation that are currently higher than the retail rate.

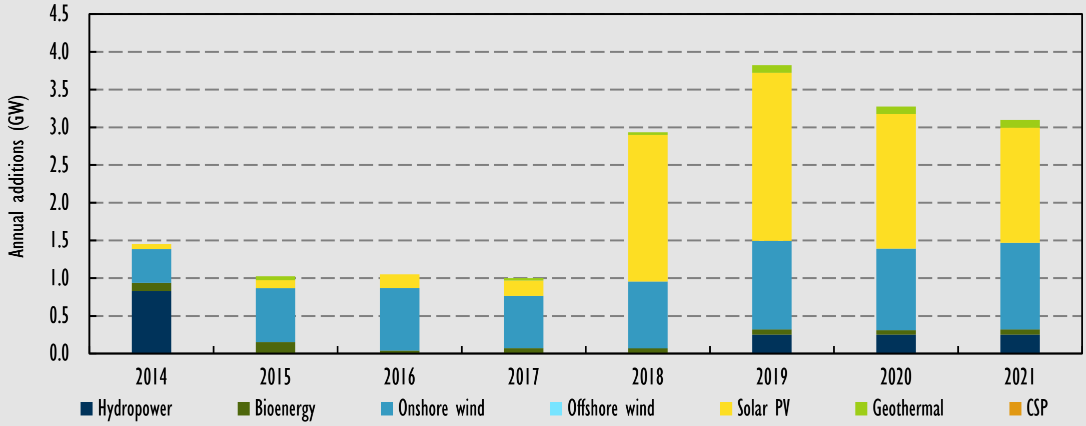
The outlook for hydropower, CSP, bioenergy and geothermal is unchanged compared with *MTRMR 2015*, as they will only benefit from a one-year extension of federal tax incentives. For bioenergy, the deployment should be slightly higher in 2016, as project developers commission their projects to be eligible for the PTC. The first commercial offshore wind plant, Block Island Wind Farm, is expected to come on line in 2016. Few other projects are expected to come on line over the medium term. For CSP, uncertainty remains over the future project pipeline beyond 2015. The geothermal forecast is stable but remains small.

Medium-term forecast: United States accelerated case

For onshore wind and solar PV, the potential for additional growth will depend on faster development and commissioning of projects before the phase-out of ITCs and PTCs, and on states’ decisions to deploy projects to get early-compliance credits before 2022. Under these conditions, onshore wind capacity could be 8 GW higher, reaching 134 GW in 2021. The accelerated case potential for solar PV assumes faster deployment of distributed generation as a result of cost improvements and improving state policies. Thus solar PV growth could be 6 GW to 16 GW higher, reaching 93 GW in 2021. Some extra growth potential is possible for bioenergy with the early compliance of CPP, especially in Arkansas, Iowa, Michigan and Louisiana.

Mexico dashboard

Figure D.20 Mexico annual net additions to renewable capacity by technology (2014-21)



Source: Historical OECD capacity derived from IEA (2016a), *Renewables Information 2016, www.iea.org/statistics/.*

Figure D.21 Mexico clean energy target

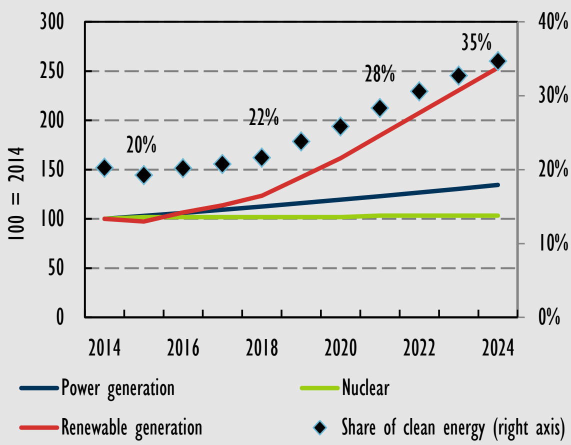


Figure D.22 Mexico first energy auction

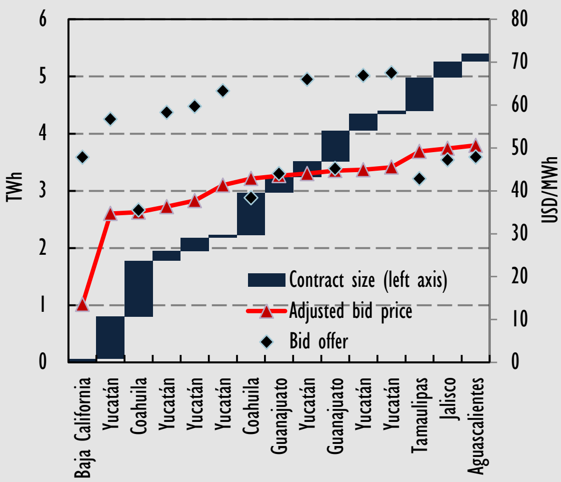


Table D.6 Mexico renewable power capacity

	2015	2017	2019	2021	2021*
Hydropower	12.5	12.5	12.7	13.2	13.2
Bioenergy	0.8	0.9	1.0	1.1	1.1
Onshore wind	3.3	4.8	7.0	9.1	10.1
Offshore wind	-	-	-	-	-
Solar PV	0.3	0.7	4.8	8.1	9.5
CSP/STE	-	-	-	-	-
Geothermal	0.9	0.9	1.0	1.2	1.5
Ocean	-	-	-	-	-
Total	**17.7**	**19.7**	**26.4**	**32.8**	**35.4**

* Accelerated case. Note: Rounding may cause non-zero data to appear as "0.0" or "- 0.0". Actual zero-digit data is denoted as "-".

- **Drivers**

- government's long-term clean energy target
- regular auctions for long-term PPAs and clean energy certificates (CECs)
- excellent resource availability
- strong commitment to decarbonisation, based on Energy Transition Law of 2015.

- **Challenges**

- weak grid infrastructure in some states
- short lead times for technologies other than solar PV and onshore wind
- relatively high cost of local financing.

Medium-term forecast: Mexico main case

Mexico's renewable capacity should expand by 15 GW over 2015-21. Solar PV and wind are expected to lead the outlook, driven by clean certificate tenders over the medium term. Overall, the forecast is more optimistic versus *MTRMR 2015,* with the capacity revised up by 5.5 GW in 2020 mostly for solar PV due to successful implementation of the energy auction. However, the forecast is less optimistic for geothermal and hydropower, as the current design of the auction does not favour technologies with long lead times.

Mexico's clean energy generation target of 35% by 2024 is ambitious but achievable under expected growth in power demand and a strong policy push. In 2014, the share of clean energy, which includes renewables, nuclear and co-generation,[4] was below 20%. This report expects Mexico's power demand to grow around 1.8% annually, with nuclear generation to remain at historical averages of around 10 TWh over 2016-21. However, the uprating of the Laguna Verde plant might increase the nuclear plant's output by 20-25% in 2021. With these assumptions, renewable generation should more than double for Mexico to reach its clean energy target, while power demand is expected to grow by only 30% from 2014 levels. This requires incremental clean electricity generation to grow on average by 10 TWh annually (3% of electricity generation in 2014). However, the fluctuation in demand growth and electricity generation from hydropower remain important uncertainties that could alter this assessment.

The economic attractiveness of solar PV and wind has improved with competitive energy auctions offering long-term PPAs. The April 2016 auction awarded 5.4 TWh of energy and CECs. Solar PV won the majority of these, with the remainder being awarded to wind. These projects translate into 1.7 GW of new solar PV and 0.4 GW of onshore wind capacity. The generation weighted average of winning bids was USD 47.5/MWh, with the lowest bid at USD 35.5/MWh. However, winning projects were not only selected by their offers, but also by their location. Locational adjustment factors reflecting nodal grid congestion, prices and local demand were added to bid offers to select winners. The majority of projects were selected in Yucatán, where the congestion level and power prices are among the highest in the country. However, projects with the largest capacity chose locations with minor adjustment factors. Winning bids will sign PPAs for 15 years and CEC contracts for 20 years based on their bid price. In addition to wind and solar PV, this report also expects co-generation projects to win contacts in the upcoming auctions.

Energy auctions should drive the deployment for solar, wind and co-generation, while policy remains a challenge for other renewable technologies. Solar PV should expand by over 8GW and wind by 6 GW over the medium term. Some delays are expected for projects that are at a very early stage of development and in locations where grid infrastructure is weak (i.e. Yucatán), as plants are required to start operation three years after the auction. In addition, this project delivery date remains challenging for other renewable technologies that require longer development and construction time. Under these conditions, hydropower should grow by 750 MW with the commissioning of projects already under construction, geothermal by 370 MW and bioenergy by 280 MW.

Medium-term forecast: Mexico accelerated case

As most of the deployment is expected through energy auctions with fixed delivery dates, the extra growth potential for Mexico is limited, at least over the medium term. Onshore wind capacity could be 0.6 GW to 1 GW higher in 2021, assuming that all auctioned projects are connected on time. The additional potential of utility solar PV is similar to wind. However, distributed solar PV capacity could accelerate with faster implementation of market reform for retail competition, which was introduced in 2015. In this case, solar PV capacity could be 0.4 GW to 1.4 GW higher by 2021. In addition, geothermal capacity could be 150 MW to 300 MW higher with specific policies tackling pre-development and drilling risks.

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

Europe

Recent trends

Renewable electricity generation in Europe[5] reached 1 277 TWh in 2015, a 6% y-o-y increase on 2014, and accounted for around 36% of total power output. Within the EU28, renewable generation rose slightly less, growing by 4% to 968 TWh. Approximately 27.5 GW of new renewable power capacity was added in Europe during 2015, with the main contribution from just over 11 GW of onshore wind. However, overall annual renewable capacity additions were significantly lower than the peaks of 38 GW observed during 2011-12.

Renewable power support measures in Europe indicate an increasing trend away from FITs and green certificates towards feed-in premiums and auction mechanisms for renewable power projects. One of the key reasons behind this transition is improved market integration of renewables, allowing greater control over capacities deployed and facilitating price discovery through competitive bidding. France held its first solar PV tender as far back as 2011, while Italy established auctions for a range of renewable technologies in 2012. Last year the United Kingdom held an initial Contracts for Difference (CfD) auction, while solar PV pilot auctions also commenced in Germany. In early 2016, Spain held an auction for onshore wind and bioenergy technologies, while in the Netherlands the Stimulation of Sustainable Energy Production subsidy scheme involves competitive bidding. The transition between different policy measures also resulted in deployment rushes in 2015 to receive more attractive support while available in countries such as Germany, Poland and the United Kingdom.

Table 1.9 Europe selected countries net renewable capacity additions and % renewable electricity generation in 2014 and 2015

Europe		Net capacity additions (GW)					% of electricity generation				
Country	Year	Bioenergy	Wind	Solar PV	Other renewables	Total	Bioenergy	Wind	Solar PV	Other renewables	Total
Germany	2014	0.6	4.9	1.9	- 0.0	7.4	8%	9%	6%	4%	27%
	2015	0.1	6.0	1.4	0.0	7.4	8%	14%	6%	4%	31%
France	2014	0.1	0.9	1.0	- 0.0	1.9	1%	3%	1%	12%	17%
	2015	0.0	1.1	0.9	0.0	2.0	1%	4%	1%	11%	17%
United Kingdom	2014	0.5	1.8	2.5	0.0	4.8	7%	9%	1%	3%	20%
	2015	0.4	1.2	3.8	0.0	5.4	9%	12%	2%	3%	25%
Turkey	2014	0.0	0.9	0.0	1.4	2.4	0%	3%	0%	17%	21%
	2015	0.0	1.0	0.2	2.4	3.6	1%	4%	0%	27%	32%

Note: Rounding may cause non-zero data to appear as “0.0” or “- 0.0”. Actual zero-digit data is denoted as “-“.

Sources: 2014 capacity data for OECD countries based on IEA (2016a), *Renewables Information 2016*, www.iea.org/statistics/. All other capacity data from multiple sources; see Chapter 2 technology sources for more detail. Generation data based on IEA (2016b), *World Energy Statistics and Balances 2016*, www.iea.org/statistics/.

[5] In the MTRMR 2016, Europe refers to the EU member states (EU28), EU candidate countries, and the European Free Trade Association (EFTA) states. Current EU candidate countries are Albania, Former Yugoslav Republic of Macedonia (FYROM), Montenegro, Serbia and Turkey. EFTA states are Iceland, Liechtenstein, Norway and Switzerland.

Renewable electricity generation in **Germany** increased by 20% to reach 202 TWh in 2015, with steady growth maintained by adding 7.4 GW of capacity. A record of around 2.2 GW of offshore wind was connected to the grid in 2015, though this was offset by a 15% decrease in net additions for onshore wind. However, gross onshore wind additions reached 3.7 GW, of which 13% was repowering, representing the second-highest annual market observed in Germany (Deutsche WindGuard, 2016). Strong deployment is likely to have been influenced by an installation rush to lock in support levels before a 1.2% reduction in the feed-in premium that came into force in 2016 and an increase in available sites from zoning modifications. Solar PV additions dropped 28% to 1.4 GW in 2015, well below the government's 2.5 GW target for a second consecutive year. Since peaking in 2012, solar PV deployment has slowed due to decreasing incentive levels, support scheme changes, and a self-consumption surcharge for commercial systems. In September 2015, FIT degressions were halted as annual deployment fell below the threshold for further reductions.

In the **United Kingdom**, renewable generation increased 26% y-o-y to reach 86 TWh in 2015. During the year 5.4 GW of new renewable capacity was added. Solar PV made the largest contribution with a record 3.8 GW deployed, the largest observed in Europe and fourth-highest globally. The majority of solar PV deployment occurred in the first quarter due to a rush of deployment before the closure of the Renewables Obligation (RO) to solar PV plants of greater than 5 MW capacity as of April 2015.

In **France**, renewable generation decreased by 3% to 94 TWh in 2015. A decrease in hydropower output (13% down y-o-y) due to well-below-average rainfall was mostly offset by increasing generation from wind and solar PV. As a result, the share of renewables in overall electricity generation remained stable at 17%. In 2015, wind (+1.1 GW) and solar PV (+0.9 GW) provided more than 95% of net additions to power capacity while smaller additions came from bioenergy and geothermal. In September 2015, France connected the largest solar PV plant in Europe (300 MW).

Italy's renewable energy generation decreased from 122 TWh in 2014 to 111 TWh in 2015, representing 39% of total power generation. The principal cause of the decrease was a reduction from 2014's exceptionally high hydropower generation towards levels more representative of the long-term trend. In 2015, new installed capacity was around 0.9 GW, the majority of which came from 0.4 GW of onshore wind in receipt of auctioned feed-in premium support and solar PV growth of around 0.3 GW, mostly from residential and commercial applications, driven by the Scambio Sul Posto (SSP) equivalent net metering scheme.[6]

Poland's renewable power generation grew by 14% to 23 TWh in 2015, amounting to 14% of total power generation. Renewable energy capacity increased strongly in 2015 with 1.8 GW added, up from 0.5 GW in 2014. Onshore wind represented the majority of new additions (+1.3 GW) while bioenergy capacity expanded by just under 0.5 GW. Robust growth, especially for onshore wind, was driven by investors rushing to complete projects before anticipated policy changes in 2016.

In **the Netherlands**, overall renewable generation increased 16% y-o-y to reach 13.6 TWh, and represented just over 12% of total power generation. Net metering regulations that allow for excess

[6] Under the SSP, the solar PV system owner receives compensation equal to the difference between the value of electricity fed into the grid and the value of the electricity consumed in a given period. The scheme is designed in order to be cost-effective, providing the electricity produced does not substantially exceed that consumed.

generation to be deducted from consumers' bills spurred residential PV, with record levels of at least 450 MW deployed. The first major (180 MW) offshore wind project since 2008 was also commissioned. In April 2016, an offshore wind tender for 700 MW of capacity took place with the winning bid (including transmission costs) around 90 euros (EUR) per MWh (USD 96/MWh) including transmission costs. Another tender is planned for later in 2016.

Renewable capacity increased slightly in **Spain** during 2015, with just over 300 MW of hydropower capacity added. In early 2016, Spain held a renewable energy auction for 500 MW of onshore wind and 200 MW of bioenergy. Even with no subsidy on offer, the auction was over-subscribed and the full 700 MW of capacity awarded. Should these projects be delivered it would indicate that further onshore wind development in Spain is possible without additional financial incentives. High interest in the auction from onshore wind developers can be explained by the relatively low tendered capacity compared with the pipeline of projects stalled since the 2012 moratorium on financial incentives for new renewable power capacity.

Sweden added just less than 1 GW of new renewable capacity in 2015, comprising 600 MW of onshore wind and 320 MW of bioenergy capacity. Onshore wind deployment in 2015 was prominent in **Belgium** (270 MW), the highest levels since 2009, **Austria** (320 MW), **Finland** (380 MW) and **Ireland** (240 MW). **Portugal** installed an additional 130 MW of onshore wind capacity in 2015 and achieved the milestone of meeting all electricity demand from renewable generation during four consecutive days in May 2016.

Outside of the EU28, **Turkey's** renewable capacity expanded 3.6 GW in 2015, with the largest contribution provided by hydropower (+2.2 GW) due to the commissioning of a number of large plants. Onshore wind (+1 GW), geothermal (+0.2 GW) and solar PV (+0.2 GW) provided the rest, with deployment driven by FITs. In **Switzerland**, despite reductions to FIT support, solar PV (+0.3 GW) dominated renewable capacity additions in 2015 as self-consumption continued to drive growth.

Medium-term outlook: Regional main case summary

Renewable generation in Europe is expected to increase by 24% over 2015-21, a small upward revision from the *MTRMR 2015* due to a slightly more optimistic medium-term outlook for onshore wind, hydropower and bioenergy. From 2016 until the end of the medium term, annual capacity additions in Europe are expected to remain between 18 GW and 21.5 GW. EU28 renewable generation is also forecast to increase by 26% over 2015-21, driven by 98 GW of additional capacity. This outlook is similar to the *MTRMR 2015,* with annual renewable capacity additions from 2016 to the end of the medium term between 14.5 GW and 17.5 GW. However, this is considerably lower than the EU28 peak of just under 36 GW annual renewable capacity additions in 2011.

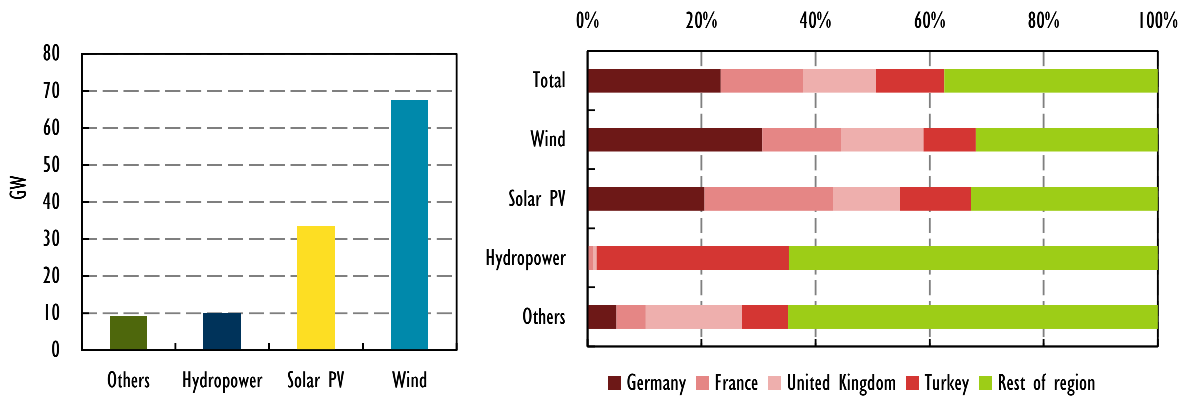
Weak electricity demand growth and changing economic incentives in several countries characterise the forecast for Europe. In some EU countries, such as Germany, Spain and Italy, high penetration of renewables in the face of sluggish demand growth has started to displace fossil fuel generation from incumbent utilities, with the combination of an oversupply of electricity capacity and low wholesale prices putting them under financial pressure. However, exceptions to this trend exist, such as Turkey and Poland, where power demand is on an upward trend, and the United Kingdom, where there is a need for new electricity generation capacity to replace ageing infrastructure.

Managing policy uncertainty remains a key challenge to renewable power project developers in several European countries given the ongoing transition at a national level between different support measures and the introduction of frameworks aimed at managing the integration of variable renewable generation. In addition, clarification regarding the governance structure to ensure compliance with the targets established within the European Commission's 2030 climate and energy framework is still pending. However, an updated Renewable Energy Directive (RED) covering the post-2020 period is expected later in 2016, and this is anticipated to be supported by other EU policies related to the governance structure to ensure compliance with the targets established for 2030. In addition, new EU policies to harmonise market design and regional balancing in the electricity sector are also in development. Progress towards the European Union's long-term electricity interconnection targets of 10% by 2020 and 15% by 2030 should facilitate the deployment of variable renewable technologies. However, doubts remain regarding the achievement of these by all member states, with 12 currently remaining below 10% levels (EC, 2016).

With regard to EU National Renewable Energy Action Plan (NREAP) targets for shares of renewable energy (across heat, power and transport) in 2020, based on the latest available data (for 2014) nine EU28 countries, including Sweden and Italy, have already met their targets. However, the European Commission stated in its 2015 renewable energy progress report (based on data up to 2014) that some member states, including France, the United Kingdom, the Netherlands, and, to a lesser extent, Spain, "will need to assess whether their policies and tools are sufficient and effective in meeting their renewable energy objectives" (EC, 2015). Greater uptake of the co-operation mechanisms[7] established within the RED may represent a means for some countries to accelerate progress towards their NREAP targets.

Of the 120 GW of renewable capacity expected to deploy in Europe over 2015-21, over half is expected to come from onshore (51 GW) and offshore wind (17 GW), with capacity additions led by Germany, France and the United Kingdom (Figure 1.18). Solar PV additions (34 GW) are highest in Germany, France and Turkey, while Denmark, Poland and the United Kingdom lead bioenergy deployment of almost 9 GW. With regards to hydropower, 10 GW of additions are driven by Turkey, followed by pumped-storage additions in Switzerland and Portugal.

Figure 1.18 Europe net renewable capacity additions by technology and country (2015-21)



[7] Established to encourage EU28 countries to work together in order to maximise the exploitation of renewable energy resources where their potential is greatest. Specific measures include statistical transfers, joint projects and joint support schemes.

Germany's renewable capacity is expected to grow by 28 GW over 2015-21, with the share of renewable electricity generation increasing from 31% in 2015 to 38% in 2021. The transition to new support schemes outlined by the latest amendment to the Renewable Energy Sources Act (*Erneuerbare-Energien-Gesetz* or EEG), EEG-2017, is expected to result in a volatile deployment pattern over the medium term as the move from FIT/premiums to auctions for large-scale systems varies by technology and introduces some uncertainty to the forecast. The outlook is less optimistic than *MTRMR 2015,* with slower distributed solar PV growth, primarily due to uncertainty over the attractiveness of commercial-scale projects (see Germany dashboard). Onshore wind is expected to expand by almost 17 GW, driven by feed-in premiums in the near term and annual auctions by 2021. However, deployment post-2018 will depend upon the economic attractiveness of repowering projects compared to new builds, as well as the impact of auction design, which incorporates volume-controlled bidding regions and tariff adjustment factors for different wind sites. The pace of grid connections and current project pipelines are expected to continue to be the main drivers for offshore wind. Cumulative capacity for bioenergy is anticipated to reach almost 9.5 GW by 2021, driven by the introduction of auctions. However, total net additions to capacity over 2015-21 may be less than tender volumes as bidders for new capacity will compete with existing plants whose support under the FIT is set to expire.

Italy is expected to deploy an additional 4.3 GW of renewable capacity over 2015-21. Accordingly, the share of renewables in electricity generation would increase from 39% in 2015 to 44% in 2021. Deployment of 2.4 GW of rooftop solar PV additions is expected over 2015-21. Self-consumption under the SSP scheme is likely to remain attractive for commercial self-consumers with daytime electricity demand located in the centre and south of the country. A new renewable energy subsidy budget was confirmed in June 2016 with the objective of incentivising deployment of technologies including new and refurbished onshore wind, CSP and bioenergy. However, solar PV is not included. For plants with capacities greater than 5 MW, support will be awarded via auctions.

In **Sweden**, renewable energy capacity is expected to increase 17% over 2015-21 to reach just over 31 GW, a similar outlook to the *MTRMR 2015*. Deployment of 2.8 GW of onshore wind is anticipated to lead the way. A reform of the green certificate scheme was introduced in 2016 to increase the overall quota of renewable generation required. However, Norway, which also participates, has announced that it will not increase the overall quotas after 2021. Solar PV deployment in Sweden is anticipated to reach 600 MW in 2021, boosted by an increase in the budget for a grant subsidy that covers 20% of initial costs for residential systems, public authorities and businesses. Bioenergy is forecast to increase by 400 MW to reach 5.5 GW by 2021, with deployment dominated by large-scale co-generation projects.

In **Poland**, renewable electricity capacity is anticipated to reach close to 11 GW in 2021. As a result, the share of renewables in electricity generation is forecast to increase to around 22% in 2021. Onshore wind capacity is expected to grow from 5.1 GW in 2015 to 6 GW by 2021. Over 2015-21, bioenergy deployment is anticipated to lead with 1 GW of additions, while solar PV is expected to grow by 200 MW. The outlook for renewable electricity is revised down compared with the *MTRMR 2015* due to legislative changes concerning the renewable energy sector that are anticipated to reduce the prospects for growth of the onshore wind and solar PV markets.

Legislation to introduce a renewable energy auction mechanism in Poland entered into force in July 2016, and is expected to be more favourable to bioenergy technologies than wind and solar PV. The legislation introduces two dedicated auction pots for projects with annual full-load hours higher than 3 504 (equating to a load factor of 40%), which is unlikely to be applicable to utility-scale solar PV projects and all but onshore wind sites with the best resources. There is however a separate auction pot for unspecified technologies in which wind and solar PV could participate provided it is allocated budget. Additionally, newly adopted regulations governing new onshore wind projects to stipulate a minimum distance to the nearest building and other wind turbines, as well as changes that will result in increased levels of real estate taxation for wind projects, are expected to slow onshore wind deployment over the medium term.

Turkey's renewable electricity capacity is expected to expand by more than 14 GW over 2015-21. Overall, the outlook is more optimistic versus *MTRMR 2015* due to generous FITs (USD 133/MWh) growing the solar PV market. The majority of solar PV development is expected to come from the small ground-mounted unlicensed project segment (50 kW to 1 MW) in which developers are not required to pay for grid connection fees. Investors have taken advantage of this by bundling several projects in the same location under different commercial entities to develop projects larger than 1 MW. However, in March 2016 the government changed the regulation to require self-consumption for new unlicensed project applications and limit generation capacity to 30 times the capacity of the associated consumption unit. The regulation also included amendments aimed at preventing developers from bundling multiple projects in the same location. Nevertheless, there are around 3 GW unlicensed projects in the pipeline under the previous regime. The *MTRMR 2016* forecasts more than 4 GW of additional solar PV capacity over 2015-21, with the majority coming from unlicensed projects while some large-scale licensed projects should also contribute.

Table 1.10 Europe main drivers and challenges to renewable energy deployment

Country	Drivers	Challenges
Germany	Targets combined with support schemes Predictability provided by a clear timeline of fixed-volume auctions. Economically attractive utility-scale PV and a tariff adjustment mechanism for onshore wind.	Balancing affordability with renewable electricity policy support mechanisms. Grid constraints and transmission capacity. Self-consumption surcharge for commercial-scale PV.
United Kingdom	Strong offshore wind pipeline coupled with policy support. Further investment in generation capacity required to replace ageing infrastructure.	Reduced support for onshore wind and solar PV and unclear post-2020 policy outlook. Renewables policy uncertainty, including CfD auction timeline and details still to be clarified.
Turkey	Growing electricity demand and need for new capacity. Competitiveness of renewable resources.	High grid connection costs for utility-scale wind and solar PV projects. Administrative and regulatory challenges for self-consumption solar PV projects. Relatively high cost of financing.
Poland	Introduction of the renewable energy law to help ease prolonged policy uncertainty. Auction system anticipated to drive bioenergy deployment.	Minimum capacity factor requirements of certain auction pots challenging for wind and solar PV projects to satisfy. No post-2020 renewable energy target in place.
France	Ambitious renewable energy targets supported by tenders, feed-in premiums and FITs. Clear schedule of solar PV tenders up to 2020. Continuation of FIT for onshore wind.	Non-economic barriers and increasing social acceptance issues for onshore wind.

Onshore wind development in Turkey is also driven by FIT support (USD 73/MWh) with more developers receiving local content premium. There are currently 3 GW to 4 GW of projects under development, with a further grid auction for 3 GW to be held at the end of 2016. Overall, onshore wind is anticipated to grow by more than 6 GW over the medium term. Hydropower capacity is expected to expand by around 3.5 GW. The outlook is less optimistic versus *MTRMR 2015*, with some delays expected for projects in the east of the country due to geopolitical risk in the region. In addition, Turkey is expected to be the leader for geothermal capacity growth in Europe with 375 MW coming on line over the medium term, driven by robust project pipeline and FIT support.

In **France**, renewable electricity capacity is forecast to expand by over 17 GW, with its share of renewables in electricity generation increasing from 17% in 2015 to 23% in 2021. The outlook is more optimistic for all technologies versus *MTRMR 2015* mainly due to the amendment of the energy transition law in October 2015 and ambitious renewable targets announced in April 2016 of 21 GW to 26 GW of onshore wind, 3 GW of offshore wind, 18 GW to 20 GW of solar PV and over 1 GW of bioenergy, all by 2023.

For solar PV, tenders are expected to drive the deployment for utility- and commercial-scale projects over the medium term. France announced a clear auction schedule for 2016-19 for 4.5 GW of new capacity. In March 2016, the regulatory authority announced the results of the tender held in 2015 for 100 kW to 250 kW projects. The average price of EUR 140/MWh (USD 155/MWh) was 9% lower than the result of the previous tender held in 2013. For large-scale projects, the last tender results in December 2015 also showed a decrease in average prices. For example, the average price for ground-mounted PV was EUR 82/MWh (USD 91/MWh), 23% lower than the previous tender in 2013. For the residential segment, deployment has been slow, as France has one of the lowest retail electricity tariffs across the European Union. Although the government announced the possibility of additional incentives and changes in self-consumption regulations to ramp up residential solar PV deployment, uncertainty remains over the timing of this new policy. Overall, solar PV is expected to expand by over 7.5 GW with total capacity reaching 14 GW in 2021.

For onshore wind, growth is expected to be driven primarily by the FIT, which is set at EUR 82/MWh (USD 89/MWh) for 15 years. With an estimated LCOE for typical projects ranging between EUR 70/MWh and EUR 75/MWh (USD 77/MWh and USD 83/MWh), onshore wind projects remain economically attractive. However, administrative requirements and social acceptance issues remain as challenges. In 2015, the government announced a “single permit” regime that would facilitate onshore wind administrative procedures. Despite these challenges, onshore wind capacity is still forecast to increase from 10.1 GW in 2015 to 17.5 GW. A first offshore wind project is expected to come on line in 2019 with total capacity reaching 2 GW by 2021. Bioenergy is seen growing by 0.4 GW over the medium term, with the first tender for 60 MW of capacity launched in 2016.

Renewable energy capacity in the **United Kingdom** is anticipated to expand from just under 33 GW to reach 48 GW by the end of the medium term. Consequently, the share of renewables in electricity generation would increase from 25% in 2015 to 38% in 2021. The outlook for offshore wind remains positive as three further CfD auctions are planned by 2020 for 730 million pounds (GBP) (USD 1.1 billion) of 15-year contracts (National Grid, 2016). These allow scope for up to 4 GW of offshore wind, and some bioenergy and ocean technologies. Initial offshore wind support will be capped at USD 168/MWh and reduced thereafter. Therefore, auction awards will depend on ongoing industry cost reductions. The details of the United Kingdom forecast are discussed in the dashboard at the end of this section. The outcome of the June 2016 referendum, which delivered a decision for the United Kingdom to leave the European Union, is likely to have implications for the energy sector and introduces further forecasting uncertainties. However, due to the timing of the decision these are not factored into the *MTRMR 2016* forecast.

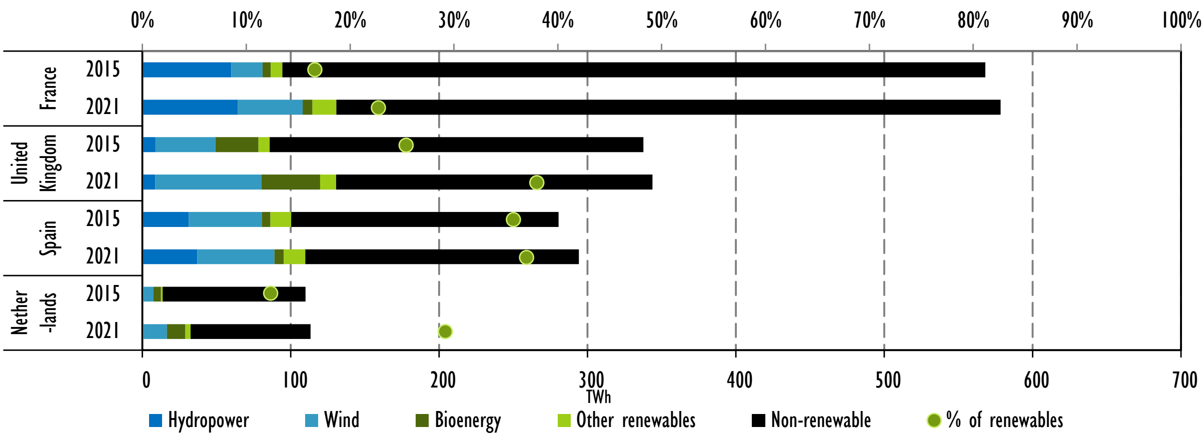
Table 1.11 Europe, selected countries cumulative renewable energy capacity in 2015 and 2021

Total capacity (GW)	2015				2021			
	Germany	France	United Kingdom	Turkey	Germany	France	United Kingdom	Turkey
Hydropower	11.2	25.3	4.5	25.9	11.2	25.4	4.5	29.3
Bioenergy	9.0	1.6	4.8	0.3	9.4	2.0	6.3	0.5
Onshore wind	41.9	10.1	9.1	4.6	58.6	17.5	12.6	10.8
Offshore wind	3.3	-	5.1	0.0	7.3	2.0	11.4	0.0
Solar PV	39.6	6.5	9.1	0.3	46.5	14.1	13.1	4.4
CSP/STE	-	-	-	-	-	0.0	-	-
Geothermal	-	0.0	-	0.6	-	-	-	1.1
Ocean	-	0.2	0.0	-	-	0.3	0.0	-
Total	**105.0**	**43.8**	**32.7**	**31.6**	**133.1**	**62.1**	**48.0**	**46.1**

Notes: For further country-level forecasts, see online Excel workbook that accompanies this report at www.iea.org/publications/mtrmr/. Rounding may cause non-zero data to appear as "0.0" or "- 0.0". Actual zero-digit data is denoted as "-".

In **the Netherlands**, renewable capacity is expected to grow 6.6 GW to reach 13 GW by 2021, an upward revision from the *MTRMR 2015*. Offshore wind auctions launched in 2016 and these should support the delivery of 1.4 GW of capacity by 2021. Net metering regulations for <15 kW solar PV systems are attractive in the residential sector due to relatively high power prices. These will remain in place until 2020, facilitating solar PV to reach over 4 GW by 2021.

Figure 1.19 Selected countries electricity generation by fuel and share of renewables in 2015 and 2021



Note: The share of renewables in total power generation includes electricity from hydropower pumped storage.

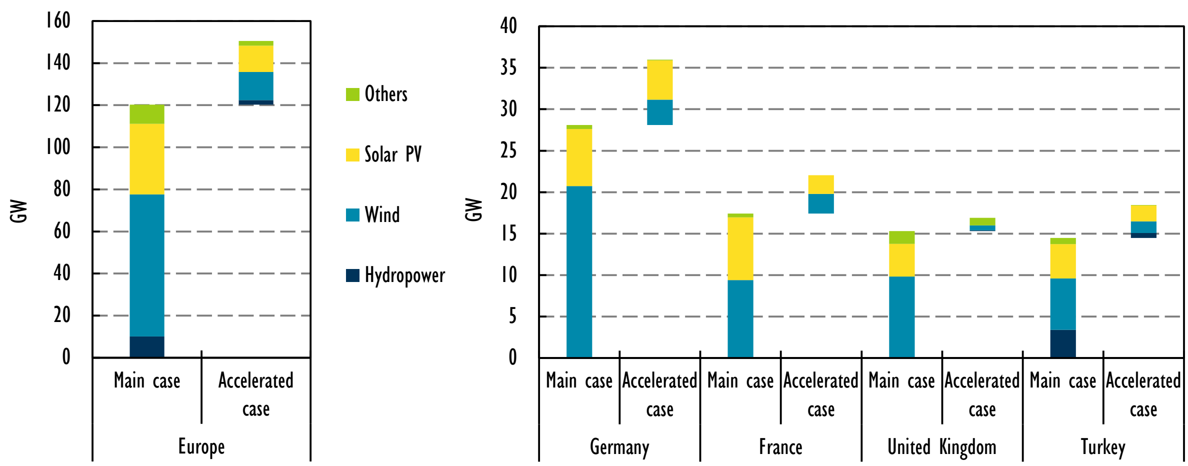
In **Spain**, renewable capacity deployment is anticipated to grow modestly by 1 GW over the medium term. Around 400 MW of onshore wind and 100 MW of bioenergy capacity are anticipated to deploy, as the absence of stringent pre-qualification criteria raises some uncertainty as to full delivery of the 500 MW onshore wind and 200 MW bioenergy capacities awarded during the 2016 auction. Low-level deployment of solar PV, around 50 MW per annum, is anticipated because of the introduction of new self-consumption legislation in 2015, which established additional charges for solar PV plants. Systems with capacities less than 10 kW are subject to a fixed charge per kilowatt of capacity, as opposed to net power demand, and there is no remuneration for power supplied to the grid for systems up to 100 kW.

Medium-term outlook: Regional accelerated case summary

Within the *MTRMR 2016* accelerated case, renewable capacity growth in Europe over 2015-21 under enhanced policy and market conditions increases from 120.5 GW expected under the main case to between 134 GW and 151 GW (Figure 1.20). In this section the accelerated case additions per technology are outlined for the Europe region as opposed to EU28.

Onshore wind has the largest potential to accelerate deployment within Europe. Cumulative onshore wind capacity in the region could be boosted as a result of enhanced market and policy conditions in France, Germany, Turkey, Poland and Spain, delivering between 5.5 GW and 11 GW of additional capacity deployment over 2015-21. In some countries that have transitioned to auctions, more regular tenders over the medium term, clearly communicated auction schedules and the inclusion of robust pre-qualification steps would reduce policy uncertainty and stimulate deployment. More streamlined permitting and grid connection would also deliver additional capacity. Offshore wind renewable capacity growth over 2015-21 could be increased by around 14% as a result of greater clarity regarding long-term policy outlook for future tenders, the delivery of industry cost reductions or additional policy support, and effective grid connection processes. The key contributors to the offshore wind accelerated case are Belgium, France and Germany.[8]

Figure 1.20 Europe and selected countries renewable capacity additions (2015-21), main versus accelerated case



Note: Outside of the four countries included in Figure 1.20 above, the rest of Europe contributes up to 12 GW to the accelerated case.

[8] In the United Kingdom, strong deployment of offshore wind within the main case in line with government expectations means that no additional accelerated case has been undertaken.

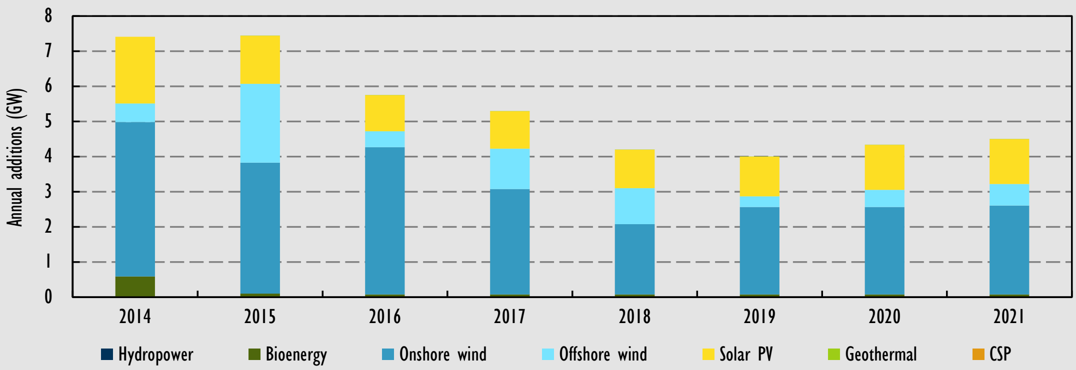
An additional 6 GW to 12.5 GW of solar PV deployment could be delivered in Europe by 2021 within the accelerated case, bringing cumulative capacity to between 136 GW and 142 GW. Belgium, France, Germany, Poland and Turkey contribute to the solar PV accelerated case. In some countries, measures to resolve policy uncertainty regarding the transition between different support schemes would enhance investor certainty and support higher delivery of commercial and utility projects. Within the residential sector, an even faster pace of industry cost reduction alongside measures to encourage self-consumption would further accelerate deployment. For both wind and solar PV technologies, greater levels of interconnection between EU28 member states, in line with the European Commission’s 2020 10% interconnection target, would be an enabler for improving the value of renewable generation.

Bioenergy capacity deployment over 2015-21 could increase by 1 GW to 2 GW with the delivery of projects from regular auctions and potential for some coal-to-biomass conversion projects in countries where coal assets are ageing or increasingly uneconomic to operate. Industry activities to grow sustainable biomass fuel supply chains, minimise fuel price risk and effectively ensure compliance with the fuel sustainability requirements of different countries will also be needed. Countries that could deliver higher levels of bioenergy deployment include Germany, Spain, the Netherlands and the United Kingdom. Municipality-led co-generation projects providing both heat and power to communities and cities offer accelerated growth potential in Sweden.

Hydropower capacity additions in Europe over 2015-21 could increase from 4% to 21%. Enhanced deployment could be delivered in Spain, Turkey and the United Kingdom should projects reach completion over a shorter timescale. While most economically attractive sites for large hydropower have been exhausted in Europe, there is still untapped potential for pumped-storage and small hydropower projects. Adequate support schemes, streamlined and less costly permitting procedures, and remuneration for ancillary grid services for pumped hydropower would lead to higher deployment.

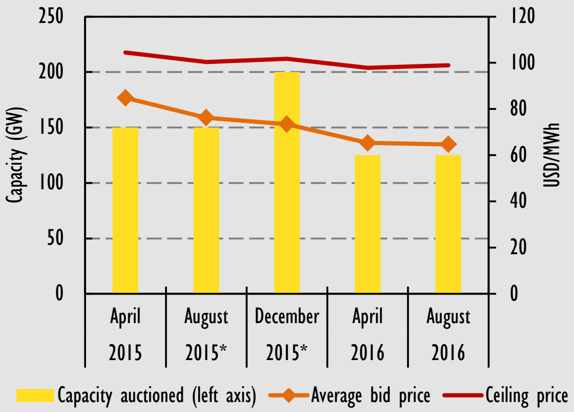
Germany dashboard

Figure D.23 Germany annual net additions to renewable capacity (2014-21)



Source: Historical OECD capacity derived from IEA (2016a), *Renewables Information 2016*, www.iea.org/statistics/.

Figure D.24 Utility-scale solar PV auction results



Notes: *Uniform price setting mechanisms used, values in the chart represent the highest bid and not the average bid prices.

Source: Federal Network Agency (2016).

Figure D.25 Solar PV deployment by segment

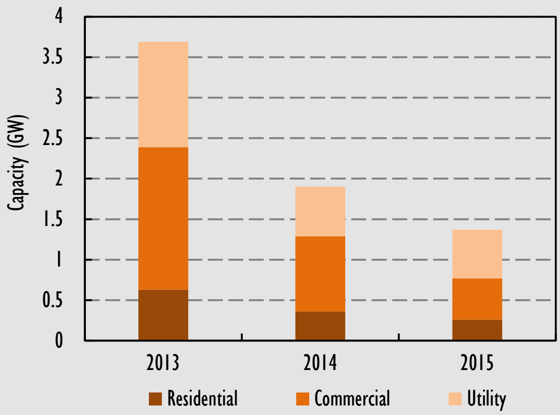


Table D.7 Germany renewable capacity (GW)

	2015	2017	2019	2021	2021*
Hydropower	11.2	11.2	11.2	11.2	11.2
Bioenergy	9.0	9.1	9.3	9.4	9.5
Onshore wind	41.9	49.1	53.6	58.6	61.3
Offshore wind	3.3	4.9	6.2	7.3	7.7
Solar PV	39.6	41.7	43.9	46.5	51.2
CSP/STE	0.0	0.0	0.0	0.0	0.0
Geothermal	0.0	0.0	0.0	0.0	0.0
Ocean	-	-	-	-	-
Total	**105**	**116.0**	**124.3**	**133.1**	**141.0**

* Accelerated case.

Note: Rounding may cause non-zero data to appear as "0.0" or "- 0.0". Actual zero-digit data is denoted as "-".

- **Drivers**

- targets combined with support schemes
-predictability provided by a clear timeline of fixed-volume auctions
-economically attractive utility-scale PV and adjustment mechanisms for onshore wind

- **Challenges**

-a need to balance affordability and policy design challenges in reforms
-grid constraints and transmission capacity
-self-consumption tax for commercial-scale PV.

Medium-term forecast: Germany main case

Germany's renewable capacity growth is expected to slow over the medium term as fixed-volume auctions are introduced to lower the economic impact on final electricity consumers and improve grid planning. Total capacity should expand by 26 GW over 2015-21, mostly from solar PV and wind, though the forecast is less optimistic than *MTRMR 2015* as uncertain economics for commercial solar PV challenge growth.

Germany seeks increased volume control and lower consumer impact in the latest reform to renewable support schemes. The EEG surcharge, which passes the cost of renewable support onto consumers, rose by 3% in 2016 to a record-high EUR 6.35c/kWh in 2016 (BMWi, 2016). A number of factors contributed to the increase, such a rise in support payments coupled with decreasing wholesale electricity prices, and discounts for electricity-intensive industries. In an effort to control the cost and pace of renewable expansion, the government approved reforms in July 2016 to replace the feed-in premium scheme with competitive auctions as the mechanism to determine support levels for large-scale renewable capacity. After five pilot auctions for solar PV, prices fell by a quarter from USD 85/MWh (EUR 92/MWh) in the first round to USD 65/MWh (EUR 73/MWh) by the fifth; all below the ceiling set by current support levels.

Annual targets for solar PV deployment may be missed if challenging economics for the commercial segment continue. With annual auctions for solar PV capped at 600 MW, Germany's 2.5 GW annual deployment target implies the remaining 1.9 GW is expected to come from distributed solar PV, an ambitious level for a segment that saw only 770 MW deployed in 2015. Distributed solar PV annual additions decreased 68% since 2013, mostly from the slowdown in commercial-scale installations (Figure D.25). This decline stems from weaker developer interest in larger systems due to decreasing support levels, increasing market exposure under the transition from FIT to FIP, and the introduction of self-consumption surcharges for systems over 10 kW. If support levels remain unchanged, limited deployment is expected for large commercial systems (100 kW to 750 kW), particularly in the absence of support for storage or tariff digression mechanism changes. However, residential systems, which are still eligible for the feed-in premium, should still find support levels attractive with high electricity tariffs and the battery rebate. Yet the extent to which residential deployment could offset the commercial segment to meet annual targets remains uncertain.

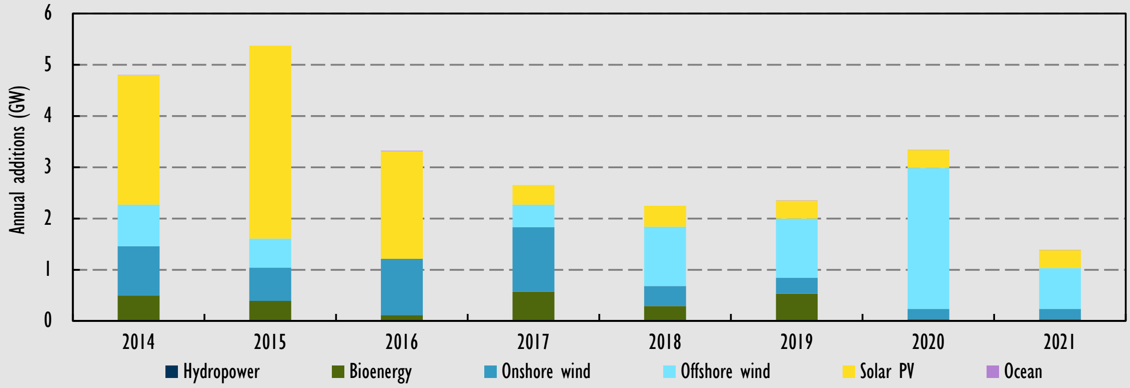
Deployment may be volatile during the transition from the current support scheme to auctions. The forecast for onshore wind carries some uncertainty, particularly in the near term when annual deployment will depend on whether developers rush to apply for expiring feed-in premiums or wait to bid in annual auctions in 2017 (2.8 GW). Once auctions begin, their ability to drive new capacity additions will depend on the economic attractiveness of new installations versus repowering projects, which will compete in the same auctions. Furthermore, it remains to be seen how the auction design, which introduces a cap on high-wind sites and adjustment factors for low-wind sites, will impact deployment patterns. Bioenergy deployment also carries uncertainty despite the introduction of new auctions, because new-build plants will also have to compete for support against existing plants with expiring FITs. For offshore wind, competitive auctions will not begin until 2021, so the pace of grid build-out will likely continue to guide the forecast over the medium term. However, transitional auctions will be introduced in 2016-17, but the impact on the current permitted project pipeline is a forecast uncertainty.

Medium-term forecast: Germany accelerated case

Solar PV additions could double by 2021 with faster growth from the commercial segment. This could be possible with increased support levels, more favourable economics for self-consumption including affordable storage, or rapid cost reductions. Design changes to the tariff regression for support for distributed PV and an increase in auction caps for utility scale would also accelerate deployment. Offshore capacity could reach 7.7 GW by 2021, the new target outlined in the new draft WindSeeG Law, depending on the pace of substation build-out and results from transitional auctions.

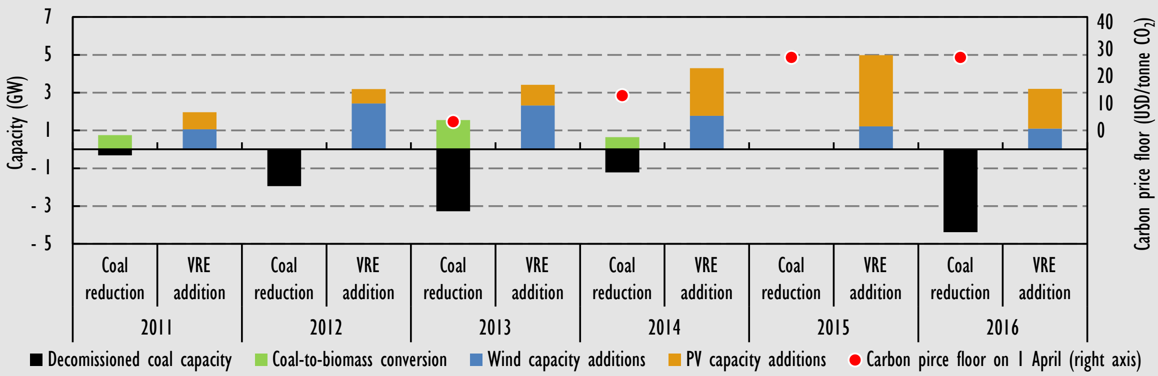
United Kingdom dashboard

Figure D.26 UK annual net additions to renewable capacity (2014-21)



Source: Historical OECD capacity derived from IEA (2016a), *Renewables Information 2016* (database), www.iea.org/statistics.

Figure D.27 UK coal capacity reductions compared with VRE capacity additions (2011-16)



Notes: VRE = variable renewable energy. One station within coal reductions was multi-fuel with oil and another with gas; VRE capacity additions in 2016 are forecast.

Source: DECC (2015), *Digest of UK Energy Statistics*. Source for historical UK renewable capacity as above.

Table D.8 UK renewable power capacity (GW)

	2015	2017	2019	2021	2021*
Hydropower	4.5	4.5	4.5	4.5	4.5
Bioenergy	4.8	5.5	6.3	6.3	6.3
Onshore wind	9.1	11.7	12.2	12.5	12.6
Offshore wind	5.1	5.5	7.8	11.4	11.4
Solar PV	9.1	11.6	12.4	12.1	13.1
CSP/STE	-	-	-	-	-
Geothermal	-	-	-	-	-
Ocean	0.0	0.0	0.0	0.0	0.0
Total	32.7	38.6	43.2	46.9	48.0

* Accelerated case. Note: Rounding may cause non-zero data to appear as "0.0" or "- 0.0". Actual zero-digit data is denoted as "-".

- **Drivers**

- strong offshore wind pipeline coupled with policy support
- further investment in generation capacity required to replace ageing infrastructure.

- **Challenges**

- reduced support for onshore wind and solar PV and unclear post-2020 policy outlook
- renewables policy uncertainty, including CfD auction timeline and details still to be clarified.

Medium-term forecast: United Kingdom main case

Renewable capacity in the United Kingdom should expand by around 15.3 GW over 2015-21, an upward revision to the *MTRMR 2015* forecast due to higher-than-expected solar PV deployment in 2015 and increased certainty regarding the delivery of large-scale bioenergy projects in receipt of CfD. Reduced policy support results in solar PV deployment declining significantly post-2016, but offshore wind prospects remain healthy and will lead annual renewable capacity additions over 2018-21 (Figure D.26). However, there is uncertainty regarding the role for renewables within the United Kingdom's energy portfolio in the context of balancing decarbonisation goals, cost to consumers and modernising an ageing generation fleet to ensure security of supply.

Solar PV provided close to 40% more power than coal for a full 24-hour period in April 2016, highlighting the dramatic shift in the United Kingdom's generation portfolio associated with strong growth in variable renewable deployment coupled with the decommissioning of coal capacity due to the EU Large Combustion Plant Directive and the higher carbon price floor of GBP 18 (USD 27.50) per tonne of CO_2 challenging generation economics. The United Kingdom has proposed to close all unabated coal-fired power stations by 2025 and restrict their use from 2023 (DECC, 2016). However, the exact definition of "unabated" in the context of the policy is yet to be defined. Significant investment in new energy infrastructure will therefore be required to maintain electricity system generation margins. However, while government support for new gas and nuclear capacity is evident, recent policy changes indicate that the role envisioned for renewables is uncertain.

The policy landscape for renewables has become more challenging since the 2015 general election. Increased focus has been given to energy subsidy budget-control via the Levy Control Framework (LCF) mechanism in order to minimise costs to consumer bills, particularly from the RO and FIT schemes. As a result, the early closure of the RO scheme for solar PV plants (≤5 MW) and onshore wind (except projects meeting specific "grace period" criteria) is now in place. Consequently, most onshore wind deployment occurs over 2016-17 as some RO qualifying projects are expected to come on line. Post-2017, deployment is expected to shrink in the absence of policy support, and with reforms that require planning authorities to demonstrate local community approval for onshore wind development. FIT support has also been scaled down via tariff reductions and the introduction of technology deployment caps. The impacts are most evident on the outlook for solar PV, which accounts for over 80% of registered FIT capacity (Ofgem, 2016).

Increased policy uncertainty poses a downside risk to the *MTRMR 2016* forecast. The aforementioned changes to the FIT and RO schemes, combined with the abrupt removal of the Climate Change Levy renewables exemption, and a lack of clarity regarding the long-term investment outlook (e.g. level of the carbon price floor, LCF budget post-2020 and the implications of exiting from the European Union) introduce uncertainty for renewables moving forward. The United Kingdom is also in the process of divesting the Green Investment Bank, which in 2015-16 supported a number of energy-from-waste and offshore wind projects, although it is planned to establish a legally binding "special share" for green projects (Green Investment Bank, 2016).

Medium-term forecast: United Kingdom accelerated case

In the current policy context, accelerated potential versus the main case in the United Kingdom is limited. Bioenergy capacity could be up to 1 GW higher if funding is allocated to coal-to-biomass conversion projects in future CfD auctions. Additional hydropower to complement growing variable renewable shares may also be delivered, with one large plant in development. Additional growth potential versus the main case is not envisaged for onshore wind and solar PV based on the current policy landscape. Without further onshore wind subsidy support, deployment potential will be linked to the competitiveness of generation costs in relation to alternative technologies. Given the challenges posed to renewable developers from the current level of policy uncertainty, the accelerated case is uncertain versus the main case.

Latin America

Recent trends

In Latin America[9], renewable power generation was stable in 2015. The share of renewables in the region, which stood at around 61% of total generation in 2015, remains the highest among all MTRMR regions thanks to a high penetration of hydropower. In 2015, the generation from hydropower declined by 1.5% since the recovery from the severe drought in Brazil was slow. Wind generation increased by 56%, while solar PV grew twofold from 1 TWh in 2014 to 1.8 TWh in 2015. Overall, renewable capacity additions were slightly higher in 2015 than in 2014, with 10 GW becoming operational, led by hydropower (4 GW), wind (3.6 GW) and bioenergy (1.3 GW). Smaller additions came from solar PV and geothermal (Table 1.11).

Table 1.12 Latin America net renewable capacity additions and % in generation (2014 and 2015)

Latin America		Net capacity additions (GW)					% of electricity generation				
Country	Year	Hydropower	Wind	Solar PV	Other renewables	Total	Hydropower	Wind	Solar PV	Other renewables	Total
Brazil	2014	3.0	2.7	0.0	0.7	6.5	63%	2%	0%	8%	73%
	2015	2.5	2.7	0.0	0.9	6.1	60%	4%	0%	8%	72%
Chile	2014	0.3	0.5	0.2	0.0	1.0	31%	2%	1%	7%	41%
	2015	-	0.2	0.4	0.0	0.6	31%	2%	1%	7%	41%
Argentina	2014	-	0.1	-	0.0	0.1	29%	1%	0%	2%	32%
	2015	-	0.0	-	0.0	0.0	29%	0%	0%	2%	31%
Uruguay	2014	0.6	0.5	0.0	0.4	1.5	74%	6%	0%	11%	91%
	2015	0.6	0.8	0.0	0.4	1.8	74%	7%	0%	11%	92%

Note: Rounding may cause non-zero data to appear as “0.0” or “- 0.0”. Actual zero-digit data is denoted as “-“.

Sources: 2014 capacity data for OECD countries based on IEA (2016a), *Renewables Information 2016*, www.iea.org/statistics/. All other capacity data from multiple sources; see Chapter 2 technology sources for more detail. Generation data based on IEA (2016b), *World Energy Statistics and Balances 2016*, www.iea.org/statistics/.

In **Brazil,** the estimated share of renewables in total power generation increased slightly and reached over 73% in 2015 despite lower hydropower generation, which decreased by 3.7% y-o-y, the fourth year in a row since the beginning of the severe drought. In 2015, onshore wind generation increased by 77% with strong capacity additions in 2014, and largely compensated for lower hydropower output. In 2015, onshore wind (+2.7 GW) and hydropower (+2.5 GW) led capacity additions, followed by bioenergy (+0.9GW).

Chile’s renewable generation increased slightly in 2015 versus 2014 and represented over 41% of the country’s electricity output. This is mainly due to higher wind and solar generation with significant capacity coming on line in the last two years. In 2015, solar PV additions (+450 MW) represented over

[9] The region of Latin America excludes Mexico, which is included in North America.

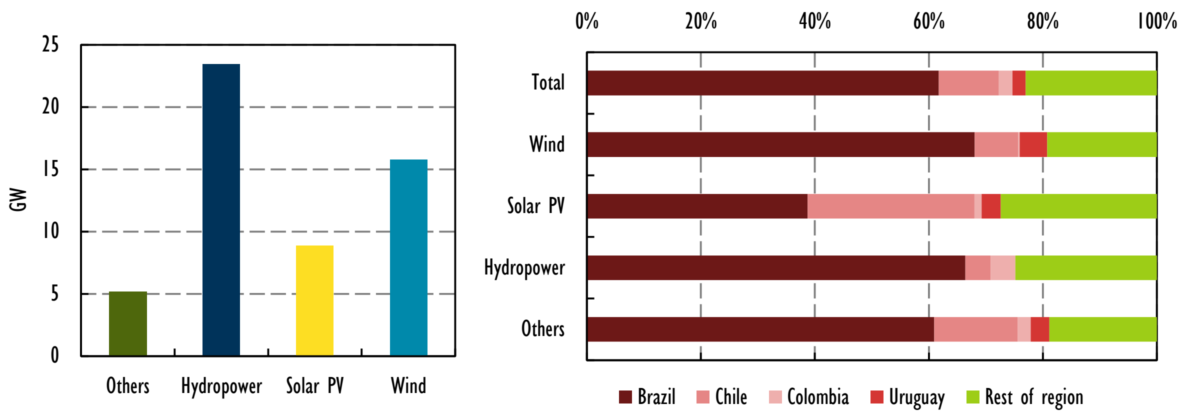
70% of new renewable capacity with the inauguration of the largest merchant solar PV plant (70 MW) globally. Onshore wind's new capacity additions stood at 170 MW in 2015, 63% lower than in 2014.

In **Argentina**, power generation continued to be dominated by natural gas, with renewables representing around 32% of the overall electricity generation in 2014, largely dominated by hydropower. In 2015, the country added only 8 MW of wind power. **Peru's** renewable power accounted for over 52% of generation in 2014. With the commissioning of four large plants (Quitaracsa, Cheves Izquierda, Santa Teresa-Ccollpani and Machupicchu), hydropower represented almost all renewable additions in 2015, with the exception of a 3 MW bioenergy plant. In **Uruguay**, the share of renewables in power generation reached over 90% last year. In 2015, the country commissioned 315 MW of onshore wind projects awarded in energy auctions in 2012. **Honduras** installed record solar PV capacity with 390 MW commissioned in 2015 driven by the generous FIT. In 2015, **Costa Rica** commissioned another 70 MW of wind, while the 235 MW Penonome wind project, the largest single project in Latin America, became operational in **Panama**.

Medium-term outlook: Regional main case summary

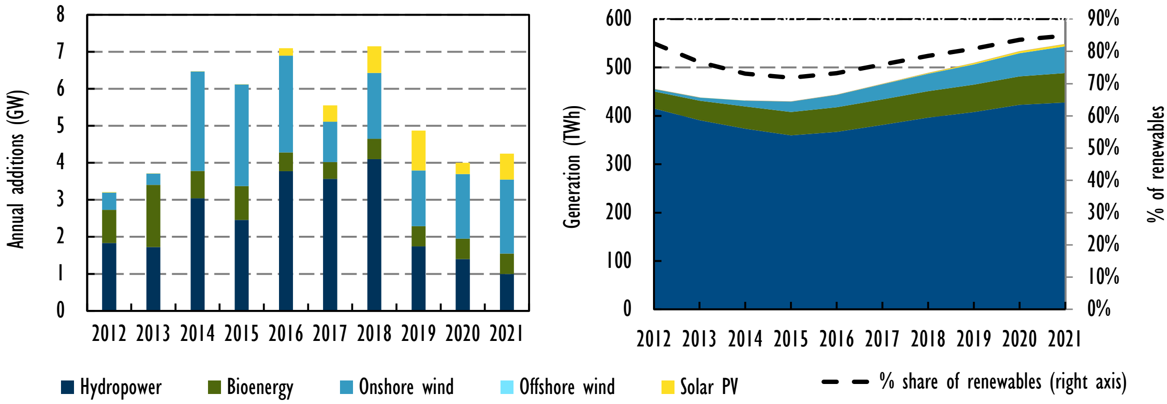
In Latin America, the renewable energy outlook is more pessimistic mainly due to the economic recession in Brazil and an economic slowdown in other countries in the region. This has two main implications for renewables. First, as the majority of regional renewable energy expansion has been driven by energy auctions/tenders administered by governments, it is likely that lower electricity demand due to the economic situation will result in upcoming energy auctions in some countries calling for less electricity capacity and generation. Second, this report expects increasing financial challenges, especially in countries where there is limited availability of low-interest debt provided by the national and/or international development banks. Overall, renewable capacity is expected to grow by 53 GW over 2015-21, dominated by hydropower (24 GW), onshore wind (16 GW), solar PV (9 GW) and bioenergy (4 GW). Brazil should represent two-thirds of renewable capacity additions in the region, followed by Chile, Uruguay and Peru, which together account for another 15% (Figure 1.21). Some additional growth is expected to come from Argentina, Panama, Colombia and Honduras.

Figure 1.21 Latin America net renewable capacity additions by technology and country (2015-21)



Brazil's renewable capacity should expand by 33 GW over the medium term. Overall, the forecast is lower versus *MTRMR 2015* due to downward revisions in onshore wind, hydropower and bioenergy. The solar PV outlook is slightly more optimistic, in line with the government's increased target under its ten-year energy plan (MME, 2015). However, the latest macroeconomic developments and the overall investment environment in the country have increased uncertainty over the renewable power forecast. Despite these challenges, Brazil's renewable power generation should increase by 28% and represent around 85% of total electricity generation in 2021 (Figure 1.22).

Figure 1.22 Brazil renewable capacity additions and generation (2015-21)



Sources: Historical generation from IEA (2016b), *World Energy Statistics and Balances 2016*, www.iea.org/statistics/.

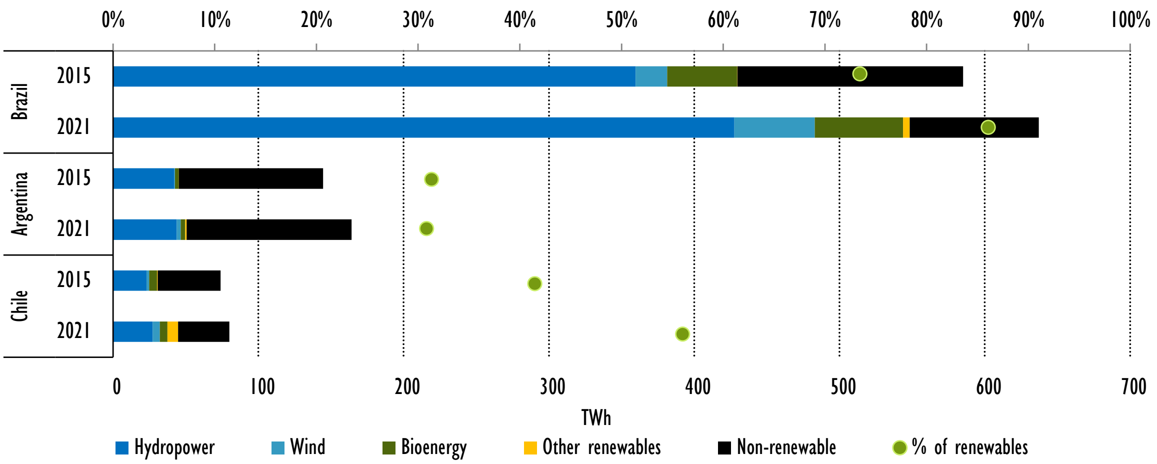
With the latest macroeconomic developments, the financing of renewables has become more expensive. The Brazilian economy shrank by 3.8% in 2015, with the country's currency depreciating against the US dollar by 40% in nominal terms over the last year. In addition, the country's consumer price index increased from 8.5% in June 2015 to 10.5% in February 2016. The initial effect of these changing macroeconomic indicators on renewable energy financing is higher interest rates. The Brazilian National Development Bank (BNDES) has played an important role in financing the majority of renewable energy and grid extension projects. BNDES' long-term interest rate reached 7.5% in May 2016, a 50% increase since December 2014. Meanwhile, the Brazilian Central Bank's long-term lending rate increased from 11.75% in January 2015 to 14.25% in July 2015, and has remained stable since. In July 2015, BNDES announced plans not to decrease its financing of renewables. While the availability of financing for new renewable projects may not be challenging, the higher cost of financing and increasing currency risks are expected to affect the bankability and profitability of future projects.

Brazil energy auctions awarded less capacity over the last year. This trend is expected to continue over the medium term due to lower growth in electricity demand. In 2015, Brazil's electricity consumption decreased by around 1% and the Energy Ministry expects this trend to continue in 2016 (MME, 2016). With a number of large and small hydropower projects currently under construction and other renewables already awarded long-term contracts, it is expected that less capacity will be awarded in future energy auctions over the medium term. The government already cancelled the energy auction that was scheduled for July 2016. In 2015, only 0.6 GW of wind capacity was awarded with the average auction price increasing from 136 reals (BRL) per MWh in 2014 to BRL 181/MWh, although the price decreased by 6% in US dollar terms (from USD 58/MWh to USD 54/MWh). In 2015, 2.2 GW of solar PV capacity won contracts to deliver power in 2018 at BRL 300/MWh (USD 81/MWh). The latest A-5 auction held in April 2016 awarded only 280 MW of capacity, selecting small hydropower and bioenergy plants. This was the first time since 2011 that wind projects did not win a contract at an auction. It is difficult to know the precise reason for this, but increasing turbine prices due to more stringent local content requirements, the increasing cost of financing and currency devaluation are likely to have been contributing factors.

Hydropower additions drive the forecast, followed by onshore wind, solar PV and bioenergy. Despite the downward revision, hydropower is still expected to expand by over 15 GW in the medium term, 3 GW lower than in *MTRMR 2015,* driven mainly by energy diversification needs after the severe drought. Onshore wind should grow by 10.7 GW over 2015-21. The forecast is revised down, with less new capacity expected to be awarded in energy auctions over 2016-18. In addition, developers are seen facing financial challenges for both new and already awarded projects due to the rising cost of debt. Since 2014 the commissioning of some wind plants has been postponed due to delays in transmission expansion. This trend might continue posing a moderate challenge to wind developers over the medium term.

The solar PV forecast is more optimistic, with 3.5 GW of new capacity expected to come on line, mostly from utility-scale projects, over 2015-21. The government has already awarded 2.7 GW of projects that are expected to be commissioned over 2017-19. The majority of these projects should not experience connection delays, as they are mostly in states where grid infrastructure is robust. However, most of them had not yet closed their financing at the time of writing. Higher interest rates (both for BNDES and commercial) and increasing exchange rate risk should pose additional challenges to developers and are expected to cause delays. Despite high retail prices and net metering scheme in place, financing also remains challenging for distributed solar PV projects. In addition, bioenergy should expand by over 3 GW, mostly driven by already-awarded capacity in the auctions.

Figure 1.23 Latin America electricity generation by source and share of renewables in 2015 and 2021



Source: Total electricity generation estimates are from IEA (forthcoming), *World Energy Outlook 2016*.

Chile's renewable electricity capacity is anticipated to grow by 5.6 GW driven by energy auctions over the medium term. This growth represents over 12% of the regional renewable capacity expansion. However, the forecast is revised down compared with *MTRMR 2015,* as this report expects growth in power demand to slow down and grid integration challenges to persist. Despite these challenges, generation from renewables is expected to increase by 46% and should represent over 50% of electricity generation by 2021.

Energy auctions have provided some revenue stability to renewable developers and are expected to support deployment going forward, but Chile will need less energy due to economic slowdown. The country's renewable energy deployment has been partly driven by merchant plants as spot prices fluctuated between USD 90/MWH and USD 180/MWh, with higher prices observed in some nodes depending on the peak demand and the level of transmission congestion. However, power prices have been decreasing due to lower fossil fuel prices in general and an increasing penetration from variable renewables in particular nodes, especially in the north where solar PV generation is concentrated. Although few merchant plants are still under construction in Chile, it is expected that they will either seek bilateral contracts with mining companies or participate in the upcoming auctions to secure long-term power agreements. With the change in auction design in 2015, renewables were able to participate in block hours (morning, afternoon and night) instead of a single 24-hour block. In 2015, renewables won 2 TWh of contracts ranging from USD 65/MWh to USD 85/MWh, offering lower prices than natural gas plants. However, the government revised down its demand expectations for the latest auction held in August 2016 by 10% to 12.4 TWh, with only 2.2 TWh to be allocated to block hours. The weighted average price of all winning bids was close to USD 48/MWh, around 60% lower than the energy auction held in December 2014, with most renewables bidding lower prices than fossil fuel plants. It is estimated that more than half of awarded contracts will come from renewable electricity. Onshore wind projects dominated the majority of block hours while the lowest winning bid (also globally) came from a solar PV project with USD 29/MWh, all to be commissioned in 2021-22.

The proposed grid reinforcement between the SING (Sistema Interconectado del Norte Grande) and SIC (Sistema Interconectado Central) grids should resolve the majority of transmission challenges, but uncertainty remains over its date of completion. In December 2015, the Copiapo-Santiago transmission line received environmental approval, which had been delayed due to opposition from local municipalities. It is expected that the USD 1 billion transmission project might face further challenges, including financing. It is anticipated that the line will not be commissioned by the end of 2017 as initially scheduled, resulting in connection delays for some wind and solar projects mainly located in the north. In addition to grid integration issues, the availability and cost of financing are likely to remain a forecast uncertainty, especially with the current macroeconomic situation despite long-term PPAs provided in the energy auctions.

Table 1.13 Latin America cumulative renewable energy capacity in 2015 and 2021

Total capacity (GW)	2015				2021			
	Latin America	Brazil	Chile	Argentina	Latin America	Brazil	Chile	Argentina
Hydropower	160.8	91.5	6.4	12.4	184.3	107.1	7.4	13.0
Bioenergy	17.9	13.3	0.9	0.6	22.2	16.4	1.0	0.8
Onshore wind	11.1	7.6	0.9	0.3	26.9	18.4	2.1	1.2
Offshore wind	-	-	-	-	0.0	-	-	-
Solar PV	1.7	0.0	0.7	0.0	10.5	3.5	3.3	0.3
CSP/STE	0.0	0.0	0.0	-	0.6	0.0	0.6	-
Geothermal	0.6	0.0	0.0	0.0	0.9	0.0	0.1	0.1
Ocean	-	-	-	-	-	-	-	-
Total	**192.1**	**112.4**	**8.9**	**13.3**	**245.4**	**145.4**	**14.5**	**15.4**

Note: For further country-level forecasts, see online Excel workbook that accompanies this report at www.iea.org/publications/mtrmr/. Rounding may cause non-zero data to appear as "0.0" or "- 0.0". Actual zero-digit data is denoted as "-".

In light of all these recent trends, solar PV additions should expand by 2.6 GW over 2015-21, with utility-scale projects dominating this growth. For residential and commercial-scale projects, access to affordable financing remains challenging. The government has set up a programme offering low-cost financing, but this initiative is limited to public buildings. Onshore wind should expand by 1.2 GW, driven by energy auctions. However, their LCOE is usually higher than that of solar PV, mainly due to relatively low capacity factors and higher system costs as some projects are located in remote areas. CSP capacity is expected to grow with 500 MW of new additions expected to come on line over the medium term. However, the CSP forecast is less optimistic versus *MTRMR 2015* as some projects are anticipated to face delays, especially those owned by Abengoa, which filed for bankruptcy in November 2015. Smaller additions are also expected from hydropower (1 GW), mainly from small projects and geothermal (100 MW).

Argentina enacted a new renewable energy law in October 2015 that pledges to increase the country's share of renewables in total electricity consumption from below 1% (excluding hydropower plants larger than 30 MW) in 2015 to 7% in 2017, 16% in 2021 and 20% in 2025. Under the new law and associated regulations, the country opened a tender to award 1 GW of renewable power projects with 20-year US dollar-denominated power purchase contracts. Developers will have two years to complete their projects. The law also introduced a new clean energy fund (FODER) to support the financing of renewables awarded with PPAs. In addition, it extended tax incentives, which include a value-added tax (VAT) exemption on renewable energy equipment, accelerated depreciation and tax credits on local content used in the project.

In light of these developments, the forecast is slightly more optimistic while uncertainties remain over the implementation of the law and its regulations. Despite the establishment of FODER, financing is expected to remain challenging considering the country's current macroeconomic situation. Argentina's previous renewable energy auction held in 2009 attracted investors, but the majority of projects were not able to secure financing. Overall, Argentina's renewable capacity is expected to grow by over 2 GW over 2015-21 driven by the upcoming energy auction. Onshore wind is forecast to expand by 0.9 GW over the medium term, mostly driven by projects that have been under development since 2010-11 but could not start construction due to financing challenges. Solar PV should grow by 0.3 GW, while hydropower should contribute with 0.6 GW over the medium term, mostly from large-scale projects. This additional capacity is expected to result in an 8% increase in renewable generation over 2015-21.

Table 1.14 Latin America main drivers and challenges to renewable energy deployment

Country	Drivers	Challenges
Brazil	Energy auctions with long-term PPAs. Availability of low-cost financing from BNDES.	Increasing interest rates and currency risk under current macroeconomic conditions.
Chile	Good economic attractiveness of renewables with excellent resources. Energy auctions with long-term PPAs.	Lack of available financing and grid bottlenecks in populated areas. Limited availability of block hours in auctions.
Argentina	New renewable energy law supported by targets, competitive tenders and financial incentives.	Financing challenges related to the macroeconomic situation.

In **Peru**, the government held an energy auction in February 2016, and awarded 330 MW of renewables with 20-year PPAs that are expected to come on line by the end of 2018. The auction resulted in record low prices for both onshore wind and solar PV. Projects totalling 162 MW of onshore wind won contracts with an average USD 37.50/MWh (60% lower than the 2011 auction) while 185 MW of solar PV signed contracts at USD 48.50/MWh (55% lower than the 2011 auction). Small hydropower (80 MW) won projects with USD 46.50/MWh and biomass (4 MW) with USD 77/MWh.

Peru's renewable energy is expected to grow by 2.3 GW over the medium term. Hydropower should dominate this expansion, with more than 1.3 GW expected to come on line over the medium term with the commissioning of Cerro del Águila (525 MW) and Chaglia (462 MW) plants in 2016-17. The forecast for onshore wind and solar PV are more optimistic considering the results of the recent auction. Thus, onshore wind is forecast to expand by 0.4 GW and solar PV by 0.5 GW, driven by the auctions held in 2012 and 2015. This report does not expect another energy auction to be awarded before 2018 as Peruvian energy demand is expected to be lower, mainly due to decreasing demand for its copper exports, the country's major energy-intensive industry.

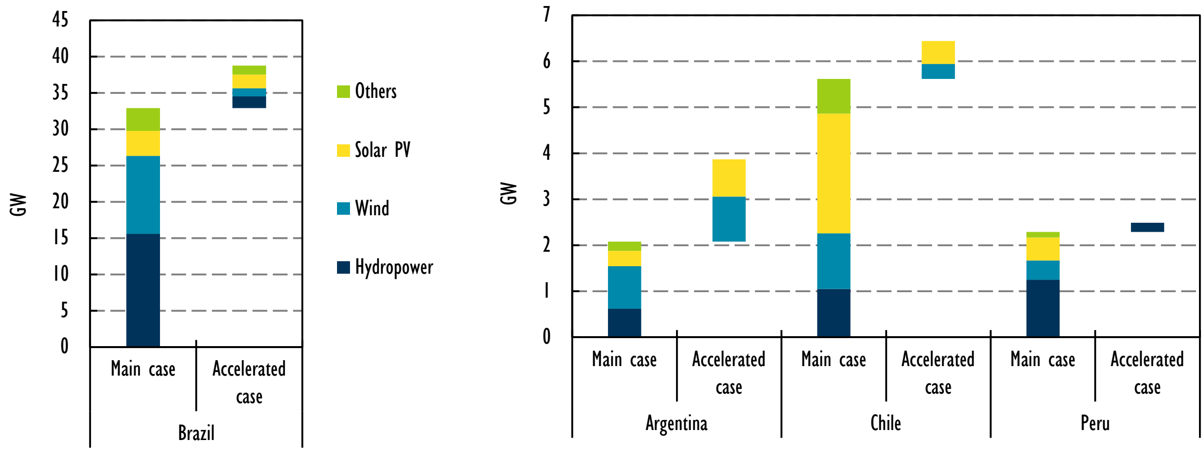
Uruguay reached its target of generating 90% of its electricity from renewables in 2015. Over the medium term, both onshore wind and solar PV projects awarded in the auctions held in 2011 and 2014 will come on line. Accordingly, onshore wind capacity should expand by 0.8 GW, reaching 1.6 GW in 2021. Solar PV capacity is expected to grow 0.3 GW driven by the auction held in 2014.

Medium-term outlook: Regional accelerated case summary

Under the accelerated case, Latin America could deploy 20% more renewable capacity versus the main case over 2015-21 (Figure 1.24). The region has excellent renewable resource potential, high electricity prices and good economic attractiveness of renewables versus expensive fossil fuel alternatives. This additional growth will be mostly driven by Brazil, but this will be highly dependent on the country's economic recovery. In **Brazil**, renewable capacity could be 9 GW higher in 2021. Hydropower could be 1.6 GW higher with faster commissioning of awarded large and small projects. The potential extra growth for onshore wind and utility-scale solar PV requires additional de-risking measures and continuous BNDES financing to attract more developers in upcoming auctions. For distributed solar PV, a clearer market framework and more attractive financing are needed to facilitate the deployment. Under these conditions, onshore wind capacity could be 1 GW higher, and solar PV capacity could be 2 GW higher in 2021. In addition, biomass capacity could be 1.5 GW higher with more favourable auction rules.

In **Argentina**, faster implementation of the new renewable energy law and tender scheme dictate the accelerated case. Policy measures focused on de-risking the financing of renewables are crucial to attract additional investment in renewables. Under the accelerated case, both onshore wind and solar PV capacity could be almost 1 GW higher by 2021. Chile's renewable energy deployment could be enhanced with higher capacity tendered in the block hours or the introduction of a market framework that facilitates long-term power purchase contracts outside of the auction. The additional expansion of renewables will also depend on further grid expansion that would ensure timely connection of renewable projects. Under these conditions, onshore wind could be 300 MW higher and solar PV could be 500 MW higher. In Peru, hydropower capacity could be 200 MW higher with the faster commissioning of hydropower projects that are currently under construction.

Figure 1.24 Latin America renewable capacity additions (2015-21), main versus accelerated case



Middle East and North Africa

Recent trends

Renewable power generation in the Middle East and North Africa (MENA) grew an estimated 8% in 2015, reaching 45 TWh. Hydropower was the largest source of renewable generation in 2015, followed by wind and solar PV. Renewable electricity accounted for approximately 3% of total power generation in 2015, similar to the share observed in 2014 and one of the lowest among all *MTRMR* regions.

Table 1.15 MENA net renewable capacity additions and % in generation (2014 and 2015)

MENA		Net capacity additions (GW)					% of electricity generation				
Country	Year	Hydropower	Wind	Solar PV	Other renewables	Total	Hydropower	Wind	Solar PV	Other renewables	Total
Morocco	2014	-	0.3	-	-	0.3	7.0%	6.5%	-	-	13.6%
	2015	-	-	-	0.0	0.0	7.4%	7.8%	0.1%	0.2%	15.5%
Iran	2014	0.3	-	-	0.0	0.3	5.0%	0.1%	-	0.0%	5.2%
	2015	1.0	-	-	-	1.0	4.9%	0.1%	0.0%	0.0%	5.0%
Egypt	2014	-	0.0	-	-	0.0	8.1%	0.8%	0.0%	-	8.9%
	2015	-	0.2	0.0	-	0.2	7.7%	1.1%	0.0%	0.2%	8.9%
Jordan	2014	0.0	0.0	0.0	-	0.0	0.3%	0.0%	-	0.0%	0.4%
	2015	-	0.1	0.0	-	0.1	0.3%	0.6%	0.2%	0.0%	1.2%

Note: Rounding may cause non-zero data to appear as "0.0" or "- 0.0". Actual zero-digit data is denoted as "-".

Sources: 2014 capacity data for OECD countries based on IEA (2016a), *Renewables Information 2016*, www.iea.org/statistics/. All other capacity data from multiple sources; see Chapter 2 technology sources for more detail. Generation data based on IEA (2016b), *World Energy Statistics and Balances 2016*, www.iea.org/statistics/.

Total renewable electricity capacity grew by 1.9 GW in 2015, double the amount added in 2014 although over half of the growth is a result of one large hydropower plant in Iran, the region's first pumped-storage project. After hydropower, solar PV led the regional deployment in 2015 with annual additions doubling compared with 2014 levels. Around 500 MW was added, almost entirely in Algeria (270 MW) and Israel[10] (220 MW). Onshore wind deployment was stable as capacity expanded by 317 MW, from 200 MW installed in Egypt and 117 MW in Jordan (Table 1.14).

Morocco's renewable generation grew modestly in 2015, an estimated 17%, driven by a full year of operations at the 300 MW Tarfaya wind plant, which was commissioned in 2014. Renewable capacity growth in 2015 was marginal – only 2 MW of CSP was added by a cement manufacturer. However, as of early 2016 100 MW of wind has already been added, and the 160 MW NOORoI Ouarzazate plant, the country's first plant under the Moroccan Agency for Sustainable Energy's (MASEN's)[11] competitive bidding scheme, was commissioned. MASEN also brought 350 MW of CSP to financial close, launched tenders for 170 MW of PV under NOORoIV PV Ouarzazate, and announced a call for tenders for another 300 MW of solar at the Midelt site. After a prolonged planning period, the winners of the competitive auctions for 850 MW of wind were announced in December 2015 at record low bids of USD 30/MWh.

Egypt's renewable generation grew to an estimated 16 TWh in 2015 from the commissioning of the 200 MW Gulf of El Zayt wind project and maintained a steady share in total power at 8.9%.

In **Jordan**, renewable generation is estimated to have tripled in 2015, seen reaching 0.2 TWh from the largest deployment of onshore wind and solar PV to date. The bulk of the growth comes from the country's first wind plant, the 117 MW Tafila wind project, which was commissioned late 2015. The remainder comes from approximately 20 MW of distributed solar PV added under the country's net metering scheme. By 2016, Jordan had already commissioned an additional 100 MW of wind and solar PV combined, mostly from the direct proposal tender scheme.

While the **United Arab Emirates**' renewable cumulative capacity remained steady in 2015, cost-effective capacity procurement continued. In June 2016, the Dubai Electricity and Water Authority announced the winners from the 800 MW Phase III tender of the Mohammed bin Rashid Al Maktoum solar park, at a record low bid of USD 30/MWh.

Saudi Arabia did not add any renewable capacity in 2015 despite its ambitious long-term targets due to a delay in carrying out the competitive auctions laid out in the King Abdullah City for Atomic and Renewable Energy (K.A.CARE) plan. However, recent developments point to the potential for renewed support and the potential for a more favourable environment for renewable investment. In April 2016, the kingdom announced plans for a series of economic reforms in the Saudi Arabia Vision 2030 aimed at reducing the national budget's dependence on oil revenues. Among the reforms that could have a positive impact on renewable deployment are continued energy price reforms and a reorganisation that moves the responsibility of electricity to the newly formed Energy Ministry.

[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.

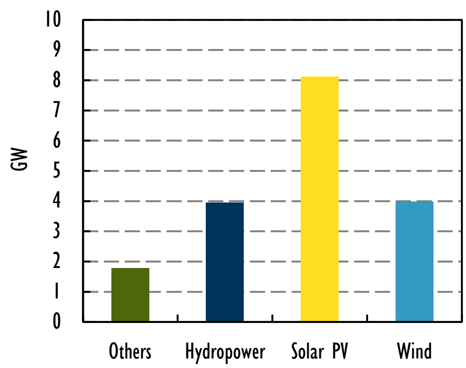
[11] In August 2016, MASEN's name was changed from Moroccan Agency for Solar Energy to the Moroccan Agency for Sustainable Energy following the passage of the law 37-16, which expanded the Agency's mandate to manage the implementation plans for all renewable energy technologies.

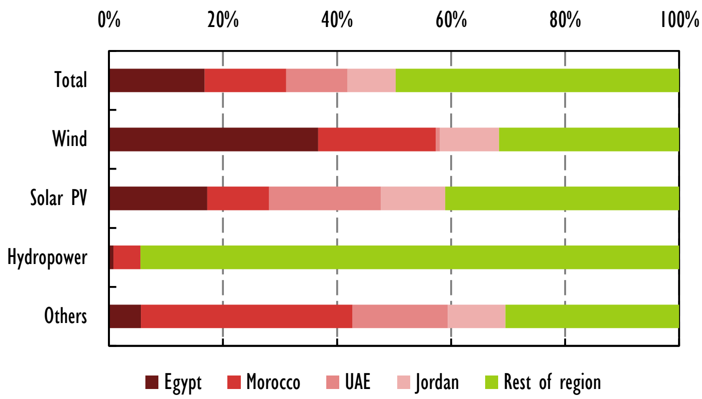
Medium-term outlook: Regional main case summary

MENA's renewable generation is expected to grow 78% over the medium term, reaching 80 TWh, or 5% of total power generation by 2021. Renewable capacity is expected to grow by 18 GW, driven by excellent resource availability and the increasing cost-effectiveness of renewables to meet robust demand growth. Iran leads the regional deployment due to large hydropower expansion while the remainder of MENA's growth is driven by countries where power generation relies on imported fossil fuels. Outside of Iran, almost 70% of MENA's deployment over the medium term is expected to come from Morocco, Jordan, Egypt and the United Arab Emirates, where decreasing import dependency remains a primary driver for renewable expansion. Conversely, in countries where meeting power demand is less dependent on fossil fuel imports, deployment is expected to be slower as there has been less momentum for diversification due to availability of domestic resources (aside from Iran).

Over the medium term, a significant portion of MENA's renewable deployment is expected to come from government-held tenders either as competitive bidding for independent power producer (IPP) projects or engineering, procurement and construction (EPC) contracts. As such, the pace and implementation of these tenders should largely guide the forecast. Solar PV is expected to lead the growth (+8.1 GW), with strong deployment expected in but not limited to the United Arab Emirates (+1.6 GW), Egypt (+1.4 GW), Israel[12] (+1.2 GW), and Morocco (+0.9 GW). Although utility-scale should dominate the solar PV forecast, distributed applications are expected to slowly pick up, driven by net metering policies in Jordan and the United Arab Emirates, though growth will ultimately depend on the evolution of end-user electricity prices across various consumer segments. Electricity price reforms for large consumers are expected to drive deployment in the commercial segment while residential solar PV growth is likely to be marginal in markets where tariffs are kept low. Cumulative onshore wind capacity is expected to triple and reach 6 GW in 2021, led by Egypt (+1.5 GW), Morocco (+820 MW) and Jordan (+400 MW). Additional hydropower capacity over the medium term will continue to be led by Iran, while the CSP expansion is expected to be driven by Morocco (+660 MW), the United Arab Emirates (+200 MW), Jordan (+150 GW), and to a lesser extent, additions in Kuwait and Oman.

Figure 1.25 MENA net renewable capacity additions by technology and country (2015-21)





[12] 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.

Supportive policy frameworks such as IPP competitive auctions, FITs and net metering should underpin the majority of the region's growth. With many markets offering long-term PPAs, increasing economic attractiveness is expected to be one of the main drivers for renewable deployment in the MENA region over the medium term, with excellent resources; continued system cost declines; and low-cost financing such as those available by state-backed institutions, concessional financing or public-private partnerships (PPP) playing a key role.

However, the limited market access for IPPs either by regulatory barriers or grid access and a lack of fully cost-reflective energy tariffs limit the region's overall pace of deployment. Vertically integrated, regulated markets characterise much of the region, although variations in liberalisation exist with varying levels of IPP participation on the generation side (RCREEE, 2015). Nonetheless, some countries, such as Morocco and Egypt, have introduced regulatory reforms over the last year to increase private investment in power generation, and subsidy reforms are under way in several countries. Still, these transitions will likely be a process over time, and the direct impact on renewable deployment levels over the medium term is difficult to predict. Grid integration and land availability are also challenges to the pace of growth in the region.

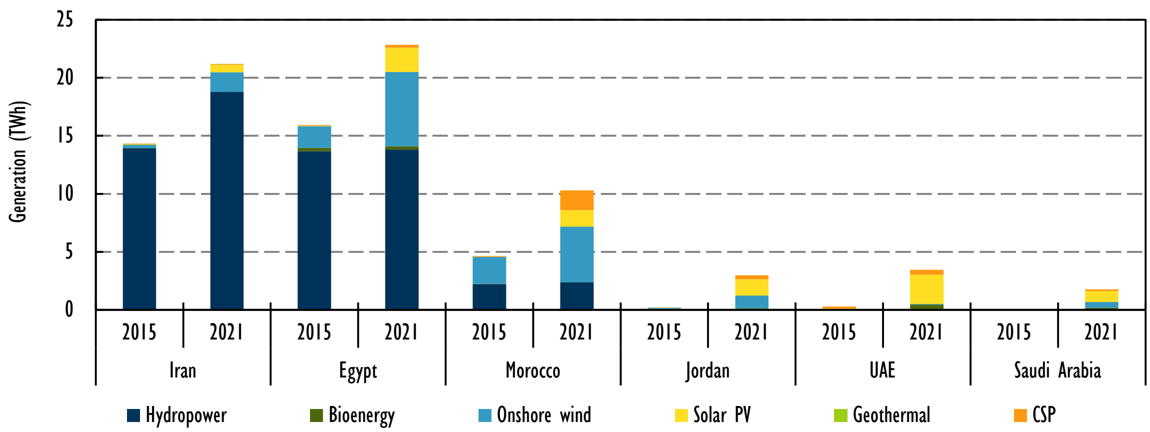
One of the most difficult, but relevant, trends to assess in the MENA region is the impact of low oil prices on renewable capacity growth. Over the last year, there appeared to be little impact on long-term plans for renewable energy in Morocco and Dubai as both announced plans to extend and increase the share of renewable energy in long-term targets. Jordan and Egypt continued with gradual energy price reforms, despite the lower cost of imported fuel. These developments suggest that decreasing the reliance on imported fuels for power generation and hedging against fuel price volatility are likely to have more of an impact on renewable deployment over the medium term than lower fossil fuel prices. For net energy exporters (excluding the United Arab Emirates and Iran), the implication of lower oil prices on renewable deployment is more uncertain and depends on the government's response to the impact of lower export revenues on national budgets. Still, some countries have used the opportunity to reform energy price structures along the supply chain, which could improve the economic attractiveness of renewables, particularly for distributed solar PV, where subsidised end-user power prices remain one of the largest barriers to deployment.

Iran's renewable generation is seen growing by 7% annually over the medium term to reach 21 TWh by 2021, driven by robust demand growth, excellent resources and ambitious targets supported by FITs. Renewable capacity is expected to grow by just under 5 GW, with almost 4 GW expected from hydropower alone from the commissioning of conventional plants and PSPs under construction. Overall, the forecast is revised up relative to *MTRMR 2015* based on an emerging pipeline for solar PV and wind projects, after relaxed trade restrictions in early 2016 and generous FITs have attracted foreign developers. Despite the changing investment climate and incentives in place, the Iranian renewable energy market for non-hydro renewables remains nascent, with the majority of projects being in the early stage of development. The cost and availability of both local and international financing is an important forecast uncertainty. Thus, the main case forecast of this report is rather conservative and expects just under 1 GW of solar PV and onshore wind projects to come on line over the medium term.

Morocco's renewable generation is expected to double over the medium term, reaching 10 TWh by 2021, driven by fast-growing demand, strong power sector diversification needs and a supportive policy environment. Renewable capacity is expected to grow robustly by 2.5 GW driven by government targets to procure renewables under several different public and private procurement models (IPP auctions, third-party PPAs and EPC contracts). Solar PV should lead the growth with 900 MW coming on line over 2015-21. While this growth is mostly driven by utility-scale projects supported by government-backed tenders for both EPC and IPP projects, some large-scale self-consumption projects should also contribute. However, despite recent reforms opening up the low- and medium-voltage grid to IPPs, the economics for distributed PV are likely to remain challenging in the absence of a clear support scheme such as net metering or FITs. For CSP, competitive IPP auctions, the availability of concessional financing, and PPP business models should drive the deployment (+660 MW) over the medium term, though the ambiguity over the capacity allocation between solar PV and CSP in tenders remains a forecast uncertainty.

Onshore wind is expected to grow by 820 MW, slightly slower than the current pipeline would suggest due to uncertainty over the pace of grid expansion to connect new projects on time and whether planned projects reach financial close. Hydropower growth is more optimistic versus *MTRMR 2015,* up by some 100 MW as a result of recent regulatory reforms. Legislation passed at the end of 2015 now allows IPPs to develop hydropower projects larger than 12 MW (up to 30 MW), which is expected improve the attractiveness of certain sites, resulting in additional deployment over the medium term.

Figure 1.26 MENA renewable electricity generation by source in 2015 and 2021



Overall, total renewable capacity is expected to reach 5.2 GW by 2021, slightly conservative relative to suggested government targets (6 GW by 2020) since the pace of tenders has slowed project development times. Still, the proposed extension of renewable targets announced during COP21, to 42% by 2025 and 52% by 2030, and the increased authority assigned to MASEN, to manage wind and hydropower plans in addition to solar under the recently adopted law 37-16, illustrate the government's commitment to increasing the overall pace of deployment. In addition, the ability for projects to secure financing through access to concessional financing and the use of PPP models should continue to drive growth. The pace of deployment for IPP projects outside of tender processes remains a forecast uncertainty as their uptake depends on the rate at which recent regulatory reforms are implemented. In late 2015, parliament passed Law 58-15 allowing IPP renewable projects connected to the higher-voltage grids to sell up to 20% of their surplus generation to a third-party consumer or the utility. This change should improve the economics for some IPP third-party supply projects and could spur additional deployment outside of government-backed tenders. However, further uptake of these projects will depend on the pace of implementation of these regulations.

Jordan's renewable generation is expected to grow from less than 1 TWh in 2015 to almost 3 TWh by 2021, driven by diversification needs and robust capacity growth led by solar PV and wind from the direct proposal scheme. Renewable capacity is expected to grow 1.5 GW and reach 1.7 GW by 2021, relatively in line with *MTRMR 2015*. However, the outlook for solar PV is more optimistic, due to project development outside of tenders and the rise of distributed PV under the net metering scheme, while onshore wind has been revised down due to grid constraints.

Solar PV and onshore wind should expand by 1.3 GW driven by a robust pipeline of projects under development, but uncertainty over the continuation of the auction scheme, grid constraints and land availability are expected to limit the pace of deployment. Having awarded 700 MW of solar PV and onshore projects under the first rounds of the direct proposal scheme, the government cancelled the third round in 2015 due to insufficient funds for the necessary grid upgrades needed to accommodate additional capacity. Some 400 MW of proposed wind projects were dropped, and there have been no indications if the tenders will be reopened. Meanwhile, a pipeline of about 300 MW of solar PV projects outside of the auctions has emerged from public EPC contracts and IPP direct negotiations with the state-owned utility, calling the grid limitations and government's commitment to the support scheme into question. This contradiction increases forecast uncertainty, as the deployment will depend on whether tenders are relaunched and the evolution of projects outside of them. In addition, developers face challenges in finding affordable land near demand centres with good resources and sufficient grid capacity, though recent funding for the Green Corridor Project, a plan to reinforce the network, should help alleviate some of the grid constraints.

Table 1.16 MENA, selected countries' cumulative renewable energy capacity in 2015 and 2021

Total capacity (GW)	2015				2021			
	Iran	Morocco	UAE	Jordan	Iran	Morocco	UAE	Jordan
Hydropower	11.8	1.8	-	0.0	15.5	2.0	-	0.0
Bioenergy	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0
Onshore wind	0.1	0.8	0.0	0.1	0.6	1.6	0.0	0.5
Offshore wind	-	-	-	-	-	-	-	-
Solar PV	0.0	0.0	0.0	0.0	0.4	0.9	1.6	0.9
CSP/STE	0.0	0.0	0.1	-	0.0	0.7	0.3	0.2
Geothermal	0.0	-	-	-	0.0	-	-	-
Ocean	-	-	-	-	-	-	-	-
Total	**11.9**	**2.6**	**0.1**	**0.2**	**16.6**	**5.2**	**2.1**	**1.7**

Note: For further country-level forecasts, see online Excel workbook that accompanies this report at www.iea.org/publications/mtrmr/. Rounding may cause non-zero data to appear as "0.0" or "- 0.0". Actual zero-digit data is denoted as "-".

Distributed solar PV is expected to grow strongly, driven by increasing economic attractiveness for the commercial segment under net metering amid rising electricity prices and the emergence of third-party leasing models. However, the economic attractiveness for the residential applications remains challenging, as their tariffs are exempt from recent subsidy reforms and will likely remain too low to stimulate deployment under the net metering scheme. Still, some residential growth is expected over the medium term from solar leasing programmes in rural communities, which are supported by the Jordan Renewable Energy and Energy Efficiency Fund.

The **United Arab Emirates'** renewable generation is seen growing to 3.5 TWh by 2021, driven by the growing need to procure cost-effective power as the country has become a net importer of natural gas since 2008 to meet rising electricity demand. Over the medium term, renewable capacity is expected to grow by 1.9 GW, led by solar PV, mostly from utility-scale projects driven by competitive auctions, though commercial-scale segments supported by net metering should also contribute to this growth.

Table 1.17 MENA main drivers and challenges to renewable energy deployment

Country	Drivers	Challenges
Morocco	Excellent resources, diversification needs. Long-term government targets supported by auctions with PPAs. Third-party sales for IPPs allowed.	Grid integration for large-scale renewables. Grid access for distributed technologies remains undefined. Limited access to commercial financing.
Egypt	Excellent resources, fast-growing demand and strong need for power sector diversification. FITs and competitive auctions.	Cost and availability of financing. Unclear support scheme procedures. Lengthy administrative barriers.
Jordan	Few domestic fossil fuel resources and strong need for power sector diversification. Low solar PV contracted prices make it cost-effective versus new generation, net metering available for distributed.	Policy uncertainty over continuation of current scheme. Grid integration challenges for new capacity. Land constraints.
UAE	Fast-growing demand and strong need for power sector diversification. Competitive auctions and net metering for distributed. Low solar PV contracted prices make it cost-effective versus new conventional generation.	Non-economic barriers to power sector participation can present investment challenges to new entrants outside of the tendering framework. Subsidised end-user electricity prices.
Saudi Arabia	Excellent resources, fast-growing demand and strong need for power sector diversification.	Vertically integrated power sector. Lack of a clear policy support mechanism. Uncertainty over timing and implementation of targets.

The increasing cost-effectiveness of utility solar PV is expected to drive deployment over the medium term in the United Arab Emirates. The most recent winning bid of USD 30/MWh from the Al Maktoum Phase III tenders is almost 50% lower than previous tender results of USD 58.50/MWh from Phase II awarded in early 2015. The winning bid is believed to have benefited from aggressive cost optimisation, particularly in operation and maintenance (O&M) and balance-of-system costs, equipment cost declines, increased yields from single-axis tracking, and access to low-cost financing. However, there is uncertainty over whether the winning bid is representative of financing costs available to other developers with similar project proposals. Still, all bids (ranging from USD 36.90/MWh to USD 44.80/MWh) were below the PPA signed for the 1.2 GW Hassyan coal plant at USD 45/MWh in June 2016 (MEES, 2016). This suggests that solar PV generation costs are comparable with new coal generation in Dubai, and in some cases with gas, when priced between USD 3.5 per million British thermal units (MBtu) and USD 6/MBtu (IRENA, 2016; MESIA, 2016). Whether such bid levels are sustainable in future auctions remains to be seen, but this forecast expects favourable economics for solar PV to remain over the medium term and to continue to attract developers to tenders in both Dubai and Abu Dhabi. Dubai's net metering scheme is expected to spur some deployment for commercial-scale PV, but growth will depend on how electricity prices evolve for large consumers and to the extent that alternative financing models, such as solar leases, can be used with the scheme.

Egypt's renewable generation is expected to grow by 43%, driven by fast-growing demand, ambitious targets and several support schemes. Wind leads the growth (+1.5 GW), followed by solar PV (+1.4 GW), mostly from utility-scale projects. Increasing electricity prices, a net metering policy and FITs should also drive some distributed deployment, particularly in the commercial segment. While robust renewable capacity growth is expected over 2015-21 (+3 GW), the forecast is revised down versus *MTRMR 2015* due to growing financing challenges and delays in administering support schemes. Egypt's renewable energy plans have spurred a robust pipeline under four different mechanisms: build-own-operate (BOO) competitive bidding, FITs, EPC tenders and merchant plants. However, unclear application procedures and financing risks have stalled many IPP projects, posing a forecast uncertainty. Developer questions over the bidding process have delayed the most recent 200 MW solar PV BOO tender, while lengthy contract negations and cumbersome administrative processes have delayed projects under the FIT programme. Financing has arisen as a major challenge due to the risks associated with foreign exchange and most recently, the government's refusal of international arbitration contract clauses, which has caused some lenders to reconsider their financial commitments. These risks are expected to result in slower deployment over the medium term than the pipeline of announced projects suggests.

Saudi Arabia is expected to grow by 0.9 GW, driven by solar PV, onshore wind and some CSP, though the forecast is revised down from *MTRMR 2015* as the government has recently changed its ambitious renewable targets. The newly announced targets (9.5 GW by 2023) imply an annual deployment rate that is almost 50% slower than previously envisioned to meet the original target of 54 GW by 2032 outlined in the 2013 K.A.CARE white paper. While the new targets released under the new King Salman Renewable Energy Initiative laid out in the Vision 2030 plan remain aggressive, the details and implementation of these targets were missing at the time of writing of this report. Still, some promising developments over the last year support the expected expansion of renewables over the medium term. The kingdom's first renewable PPA was signed for a 50 MW solar PV plant at USD 50/MWh in August 2015, and in June 2016, the first IPP competitive tenders for 100 MW of solar PV were opened, a significant step after years of delay under the K.A.CARE programme. Still, limited market access for IPPs and energy subsidies remain a barrier to deployment.

Elsewhere in MENA, **Israel's**[13] renewable capacity is seen growing by almost 1.7 GW, 20% annually, over 2015-21, led by solar PV (+1.2 GW) and wind (+0.2 GW). Despite this robust growth, Israel's forecast is revised down relative to *MTRMR 2015* due to policy uncertainty, as the implementation mechanism to procure the 520 MW of solar PV capacity earmarked by the government for support remains to be defined. In addition, the future of the net metering scheme after the 400 MW cap is reached remains unclear.

[13] 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.

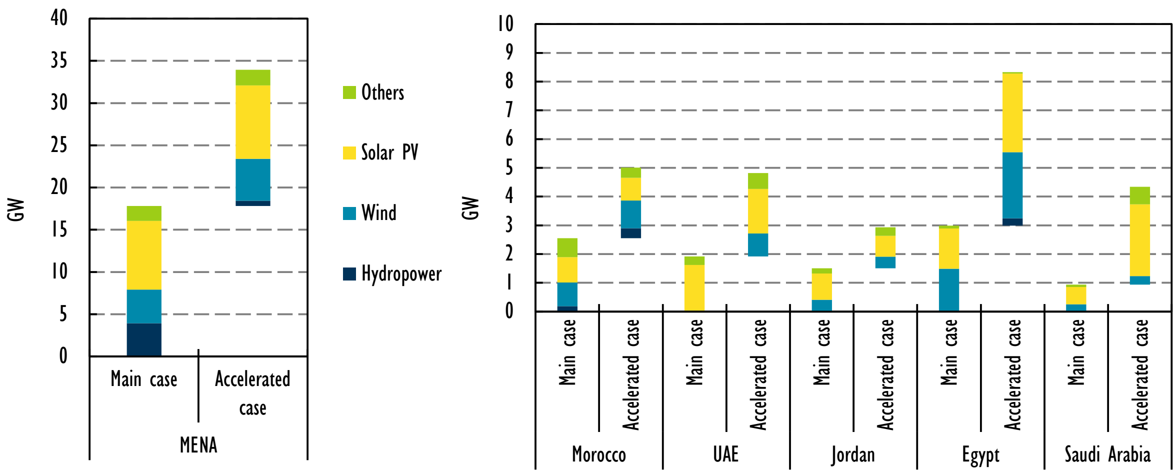
Medium-term outlook: Regional accelerated case summary

Given MENA's fast-growing power demand, excellent resource potential and increasing economic attractiveness of renewables, a much stronger outlook in the region is possible over the medium term. Under the accelerated deployment, MENA's renewable capacity growth could almost double over 2015-21 with increased government support and a rapid progression through ongoing market and regulatory reforms. MENA's renewable expansion could increase by 16 GW with an acceleration of government tenders, more streamlined and clear support scheme procedures, and readily available low-cost financing.

The largest potential for accelerated deployment exists in **Egypt**, where a pipeline of backlogged wind and solar PV projects under the FIT scheme await financial close and capacity remains to be tendered in delayed competitive auctions. Egypt's renewable capacity growth over 2015-21 could be around 5 GW higher if the government increases the pace of implementation. Such conditions would require major financing risks, such as currency convertibility, to be mitigated and more streamlined support scheme processes.

More than 3 GW of additional renewable capacity, mostly from solar PV, could be deployed in **Saudi Arabia**, where excellent resources, land availability, ambitious targets and the plans for economic reform make the kingdom an attractive market. Such a commitment would require rapid clarification of a supportive policy framework and timely implementation.

Figure 1.27 MENA renewable capacity additions (2015-21), main versus accelerated case



Quicker tender procedures to move through auctions and secure financing for planned projects as well as clarification over regulatory reforms in **Morocco** could drive 2.5 GW of additional renewable capacity by 2021. Solar PV growth could almost double, driven by faster uptake of distributed solar PV, if clarifications over grid access and net metering occur. Almost twice as much cumulative renewable capacity could be installed in Jordan by 2021 if policy uncertainty surrounding the direct proposal tender scheme was resolved and auctions were reopened. This would require grid upgrades and transmission line build-outs to integrate new capacity as well as a redesign of the tender scheme to better synchronise winning bids with available grid connections. Renewable capacity in the **United Arab Emirates** by 2021 could reach 5 GW, more than twice the main case, if the pace of competitive auctions were increased and electricity subsidies for small consumers were removed, particularly in the residential sector, to improve the attractiveness of distributed PV across all consumer segments.

Sub-Saharan Africa

Recent trends

In SSA, renewable electricity generation remained relatively stable in 2015 around 120 TWh as the growth from non-hydropower renewables offset the declines in hydropower generation from ongoing drought conditions in a number of countries. However, power demand is estimated to have grown at a slightly faster pace, and as a result the share of renewables in total power generation dropped to 26% in 2015, down from 27% in 2014, though the trend remains to be confirmed by official statistics.

Table 1.18 Sub-Saharan Africa net capacity additions and % in generation in 2014 and 2015

Sub-Saharan Africa		Net capacity additions (GW)					% of electricity generation				
Country	Year	Hydropower	Wind	Solar PV	Other renewables	Total	Hydropower	Wind	Solar PV	Other renewables	Total
South Africa	2014	0.0	0.6	0.8	0.0	1.4	1.6%	0.4%	0.4%	0.1%	2.6%
	2015	0.0	0.5	0.0	0.1	0.6	1.7%	1.2%	0.9%	0.6%	4.4%
Kenya	2014	-	0.0	0.0	0.3	0.3	36%	0.4%	0.0%	45%	82%
	2015	0.0	-	0.0	0.0	0.0	37%	0.8%	0.4%	52%	91%
Ethiopia	2014	-	-	0.0	0.1	0.1	96%	4%	-	0.2%	100%
	2015	0.2	0.2	-	-	0.3	85%	8%	0.0%	1.2%	95%
Other SSA	2014	0.3	0.0	0.0	0.0	0.4	54%	0.1%	0.0%	0.8%	54%
	2015	0.3	0.0	0.0	0.0	0.3	45%	0.1%	0.3%	1.6%	47%

Note: Rounding may cause non-zero data to appear as "0.0" or "- 0.0". Actual zero-digit data is denoted as "-".

Sources: 2014 capacity data for OECD countries based on IEA (2016a), *Renewables Information 2016*, www.iea.org/statistics/. All other capacity data from multiple sources; see Chapter 2 technology sources for more detail. Generation data based on IEA (2016b), *World Energy Statistics and Balances 2016*, www.iea.org/statistics/. 2015 generation data for South Africa from CSIR (2016), *Statistics of Wind and Solar PV in South Africa in 2015*.

South Africa's renewable generation increased by an estimated 70% in 2015 versus 2014 due to new capacity added under the country's Renewable Independent Power Producer Procurement Programme (REIPPPP). As a result, the share of renewables in total generation is estimated to have increased from 2.6% in 2014 to over 4% by 2015. As of December 2015, the Department of Energy had procured 6 377 MW of renewable energy from over 90 projects and has already connected over 2 GW to the national grid. The REIPPPP continued to drive strong investor interest and confidence, but renewable capacity growth in 2015 (+0.6 GW) was at a slightly slower pace than in 2014 (+1.4 GW). Onshore wind made up most of the additions (80%), along with some contribution from CSP, but the overall decline was caused by a drop in solar PV installations. Grid constraints delayed the financial close of more than 1.5 GW of solar PV and wind projects from round 3 of the REIPPPP, which caused a lull in the construction pipeline. However, growth will rebound in 2016; over 800 MW have already been commissioned in the first half of 2016 from solar PV, CSP, wind and pumped-storage hydropower.

Kenya's renewable generation grew an estimated 18% in 2015 to reach 9 TWh, an estimated 90% of total power generation. The increase was due to an upsurge in geothermal generation, 20% higher than in 2014, due to a full year of operation from approximately 330 MW that was added at the end of 2014. Renewable capacity expansion in 2015 was modest with less than 50 MW coming on line, mostly from the addition of several geothermal wellheads in the Olkaria field but also from the commissioning of Africa's first utility-scale grid-connected biogas plant. The 2.2 MW plant was installed by a vegetable exporter and is the first bioenergy plant to receive support under the FIT.

Hydropower continued to dominate **Ethiopia's** power generation in 2015, accounting for almost 100% of the electricity output in the country. However, absolute levels are estimated to have declined in 2015 due to rainfall deficits and droughts exacerbated by the El Niño weather phenomenon. Still, renewable capacity additions in 2015 (340 MW) doubled versus 2014 with the commissioning of two large projects (187 Gilgel Gibe III hydropower plant and the 150 MW Adama II wind farm).

Elsewhere in SSA, hydropower led renewable capacity additions in 2015, mostly from the 240 MW Kaleta project commissioned in **Guinea.** Solar PV continued to expand in several countries as well. **Ghana** added 20 MW of solar PV in 2015, from the country's first utility-scale plant commissioned under the FIT. Utility-scale solar PV was also deployed in **Mauritania**, **Mauritius**, **Namibia** and **Rwanda**, totalling 28 MW. The region has large potential for distributed solar PV, particularly in off-grid applications and mini-grids, but the size and dispersed nature of the installations make them difficult to track. However, recent developments suggest the segment is growing. **Uganda** commissioned a 600 kW solar PV-diesel hybrid plant under the country's FIT in 2015, and it is estimated that 1.6 million units of pico-solar products were sold in the first half of 2015 (Lighting Global and BNEF, 2016).

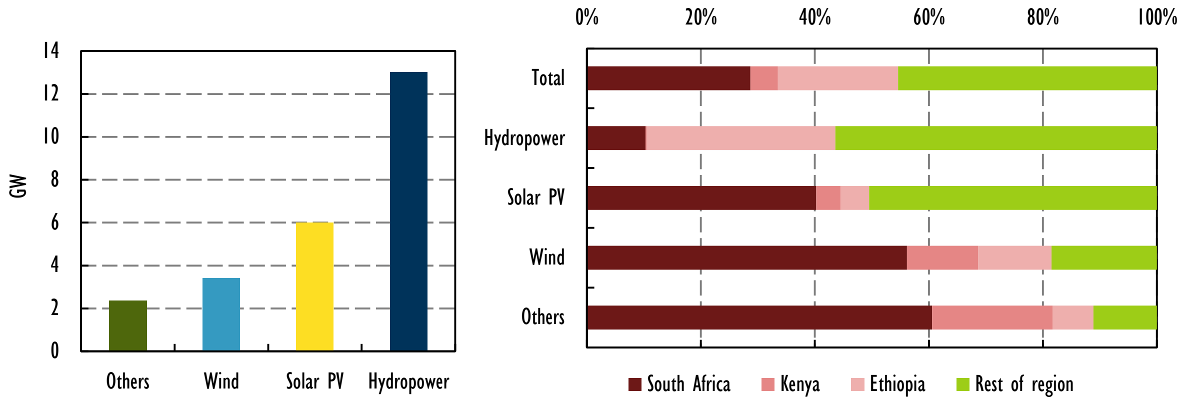
Medium-term outlook: Regional main case summary

SSA's renewable capacity is expected to grow by 10% annually over 2015-21, driven by new capacity needs to meet fast-growing demand, improving electricity access, and diversification away from an over-reliance on hydropower and costly fossil fuel generation stemming from significant diesel use in some countries. Growth over the medium term is increasingly driven by the prospect of renewables to provide the region with much-needed cost-effective power, particularly in markets where supportive policy frameworks have been created to take advantage of excellent resources and falling investment costs. However, a number of challenges still limit the pace of deployment including grid integration, off-takers' credibility, difficult market access for IPPs, and the high cost and limited availability of financing.

Over the medium term, renewable capacity should grow by 25 GW, and reach 53 GW by 2021, roughly in line with *MTRMR 2015* though country-level revisions exist. Over half of the expected deployment is from hydropower, mostly in **Ethiopia** and **Angola**. Non-hydropower renewable capacity is seen tripling over the medium term, growing by almost 12 GW mostly from solar PV (+6 GW) and wind (+3.4 GW) additions across multiple markets, but also from CSP, seen scaling up in **South Africa**, and geothermal, mostly from **Kenya** (Figure 1.28).

Off-grid solar PV applications (defined as systems not connected to main transmission lines) have particularly strong potential in SSA given the low electrification rate (32% regionally, though shares vary by country) (IEA, 2015c). This segment is expected to ramp up over the medium term, driven by mini-grid applications for rural electrification, stand-alone systems for large electricity consumers off the grid and solar-home systems for domestic use. For larger system applications, the evolution of storage costs over the medium term will play an important role in the pace of deployment. For residential off-grid applications, the high up-front costs can remain a challenge where customer bases often have low income levels. However, innovative business models such as "pay-as-you-go" schemes and pico-solar products, which package panels with electrical appliances, have made solar home systems more affordable, and thus more frequently installed, particularly in East Africa.

Figure 1.28 SSA net renewable capacity additions by technology and country (2015-21)



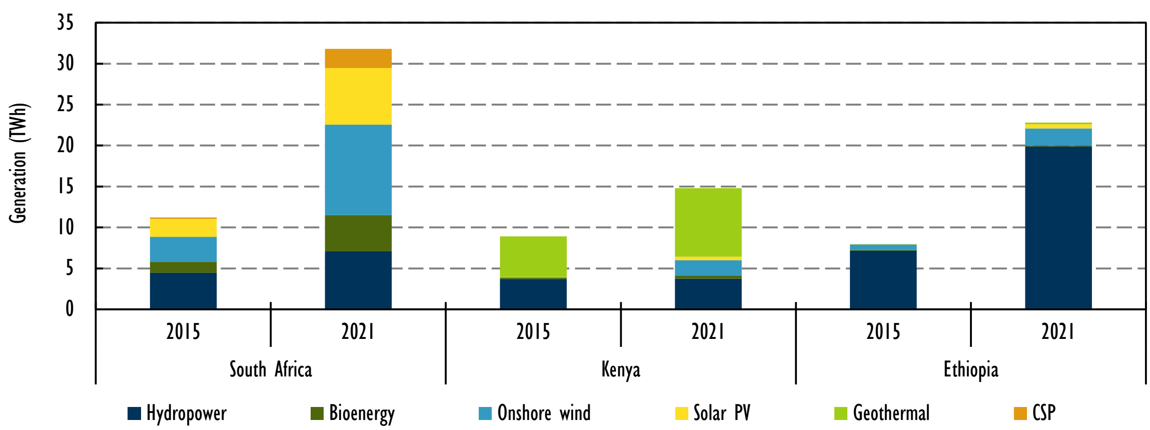
South Africa's capacity is expected to reach 12 GW by 2021, driven mostly by solar PV and wind additions from competitive auctions alongside some additional hydropower; however, the forecast is revised down versus *MTRMR 2015* due to the continued uncertainty over the pace and cost of grid connections. South Africa's need for new capacity, coupled with a supportive and highly praised institutional framework and a strong commitment from the government, has resulted in a robust pipeline of renewable projects under the REIPPPP. To date the programme has attracted almost USD 20 billion in investments by procuring 6.3 GW of renewable capacity from the first four rounds. In addition, there are plans to tender at least 2.4 GW more in forthcoming rounds in the near term to help meet long-term targets of 19 GW of renewable capacity by 2030. However, grid constraints and policy uncertainty remain the most significant challenges to renewable deployment over the medium term.

The state utility Eskom, the monopoly buyer of renewable power generation, triggered a public discussion in July 2016 following reports it would be unwilling to sign further PPAs beyond the preferred projects selected under bid window 4.5 of the REIPPPP without further engagement with the government. Network upgrades are needed to integrate additional solar PV and wind capacity, and discussions over the cost and lead times have delayed the financial close of winning bids and caused timelines for tendering future capacity to be pushed back. The timeliness in resolving the cost of grid expansion and source of capital could significantly affect the pace of renewable deployment; however, both remain major forecast uncertainties at the time of writing. These challenges are exacerbated by policy uncertainty over longer-term energy planning. An update of the Integrated Resource Plan, with updated demand forecasts and technology costs, is overdue. Nonetheless, the Department of Energy issued a clear signal to parliament at the end of August that it remains committed to the REIPPPP.

While costs for solar PV and wind have fallen significantly over four bidding rounds – solar PV by 70% and wind by 50% – the trend in future rounds is uncertain. Project costs have the potential to increase if developers are required to contribute to the cost of grid expansion through self-build options or other cost-sharing models. This largely depends on how the new Renewable Energy Development Zones (REDZ), geographic areas earmarked for renewable capacity expansion and new transmission lines, are integrated into future bidding rounds and align with grid planning. However, lower costs could also be achieved if the increased allocation of capacity in future bidding rounds continues to contribute towards economies of scale and reduced volume risks for local manufacturers. The 28% depreciation of the South African rand over the last year, increasing exchange rate risks and relatively high local interest rates may result in higher risk premiums, depending on the financing structure of the project. Local content requirements also have the potential to raise expenses, particularly if requirements are increased in future rounds resulting in higher demand than local supply chains can meet. Conversely, the proportion of the components sourced locally could increase the rand-denominated project costs, which may offset some of the effects of a weakening rand exchange rate.

Despite these challenges, growth is expected to continue over the medium term with renewable capacity seen expanding by over 7 GW, though the forecast is highly sensitive to the results of the discussions over the costs of grid integration. While overall deployment is expected to benefit from increased co-ordination among stakeholders in national energy planning, network operators and capacity procurement, the lead times for grid upgrades are a forecast uncertainty. Solar PV is expected to lead the deployment (+2.4 GW), mostly from utility-scale projects, though an increase in the commercial segment is expected as rising electricity prices (+9% this year) and increasing need for self-reliance improve the attractiveness for large consumers. Growth in the residential segment is expected to remain rather limited in the absence of an approved nationwide net metering regulation. Onshore wind is seen growing by 1.9 GW, though the growth is contingent upon the timely financial closure of round 4 projects. Hydropower and CSP are expected to grow by 2 GW combined, equivalent to the pipeline of projects currently under development.

Figure 1.29 SSA renewable electricity generation in 2015 and 2021



Note: The share of renewables in total power generation includes electricity from hydropower pumped storage.

Kenya's renewable electricity capacity is expected to grow by 80% and reach 2.7 GW by 2021, driven by government plans to utilise the country's excellent resources to diversify away from hydropower and costly diesel generation. With government targets (42% renewable capacity by 2033) backed by FITs, renewable capacity is expected to grow by 1.2 GW over 2015-21, though the cost of financing and land rights are expected to limit the growth. Overall, the forecast is revised up relative to *MTRMR 2015* due to a more optimistic outlook for solar PV and geothermal.

Geothermal is expected to lead renewable capacity growth, seen expanding by 440 MW over the medium term, driven by excellent resource potential in the Rift Valley and an overall target of 5 GW by 2030. However, the high up-front costs during exploration stages limit the pace of deployment. The government considers geothermal a low-cost form of base-load power that will improve energy access as well as meet overall development goals and has therefore prioritised its development. As such, the public utility has planned to develop a number of sites, though with limited funds for exploration, access to concessional financing will likely remain critical for state-owned projects to be realised. Private investment is expected to play an increasing role, supported by FITs (USD 88/MWh), though its effectiveness in stimulating deployment will ultimately depend on the government's involvement in mitigating pre-development risks. The recent tenders of 105 MW at the Menengai site are one example of such involvement in which the state-owned Geothermal Development Company performed the exploration and drilling, and then tendered three turnkey steam sites to IPPs.

The solar PV forecast in Kenya has been revised up based on an emerging pipeline of new projects under the country's FIT (USD 120/MWh) and rising distributed solar PV market. Utility-scale deployment to date has been slow under the FIT as developers face high costs due to financing risks, limited access to local debt, high balance-of-system costs and insolvent PPA clauses. However, a number of projects between 20 MW and 40 MW are expected to sign PPAs with Kenya Power, suggesting the economics may be improving. Increasingly standardised PPAs and streamlined processes are expected to further drive down transaction costs and attract developer interest. High electricity prices and falling system costs are also expected to increase the attractiveness for self-consumption for commercial consumers, particularly to replace costly backup diesel generators. A 37 kW system with battery storage was installed in a nature conservatory in 2015, and two larger systems are being developed at a distillery and a university to offset the costs from diesel generators. Off-grid solar PV is also seen expanding, particularly from solar PV hybrid systems for mini-grid applications driven by rural electrification aims and solar home systems for domestic users.

Table 1.19 SSA cumulative renewable energy capacity in 2015 and 2021

Total capacity (GW)	2015				2021			
	South Africa	Ethiopia	Kenya	Other SSA	South Africa	Ethiopia	Kenya	Other SSA
Hydropower	2.3	2.1	0.8	18.1	3.6	6.4	0.8	25.4
Bioenergy	0.3	0.2	0.1	1.0	1.1	0.3	0.1	1.2
Onshore wind	1.1	0.3	0.0	0.1	3.0	0.8	0.4	0.7
Offshore wind	-	-	-	-	-	-	-	-
Solar PV	0.9	0.0	0.0	0.4	3.3	0.3	0.3	3.4
CSP/STE	0.1	-	-	-	0.7	-	-	-
Geothermal	-	0.0	0.6	-	-	0.1	1.0	-
Ocean	-	-	-	-	-	-	-	-
Total	**4.7**	**2.7**	**1.5**	**19.5**	**11.8**	**7.9**	**2.7**	**30.8**

Note: For further country-level forecasts, see online Excel workbook that accompanies this report at www.iea.org/publications/mtrmr/. Rounding may cause non-zero data to appear as "0.0" or "- 0.0". Actual zero-digit data is denoted as "-".

Onshore wind is expected to grow by 430 MW, driven by EPC and IPP projects, but land governance issues pose an increasing risk. In 2016, the first IPP project to reach financial close (60 MW Kinangop) was abandoned when land disputes with local communities caused project delays and cost overruns. In addition, way-leave acquisition has delayed the completion of transmission lines set to connect the first units of the 310 MW Lake Turkana project. Residues from Kenya's agricultural industry coupled with government support should stimulate bioenergy deployment. A 20 MW plant using bagasse has just signed a PPA for the FIT (USD 100/MWh).

In **Ethiopia**, renewable capacity is expected to grow 5.2 GW led by hydropower additions, which account for over 80% of the total expansion. The government's plan to position the country as a regional exporter of electricity has resulted in over 6 GW of large hydropower projects currently under construction. However, this forecast expects only an additional 4 GW to be commissioned by 2021, due to the uncertainty over the pace of construction, the pending results of environmental impact studies, and the availability of financing. Public sources of financing, such as bonds and taxes, are expected to remain important, but securing additional amounts may be a challenge. While electricity sales to neighbouring countries are expected to contribute to the bankability of some projects, monetising these revenue streams will depend on sufficient grid interconnections which are capital-intensive. Chinese investment is seen playing an increasing role in contributing to the development (IEA, 2016d).

The remainder of Ethiopia's renewable capacity growth, around 1 GW, is expected to come from utility-scale solar PV, wind, bioenergy and geothermal projects from a mix of public EPC and private projects, although the ability to attract IPPs has been limited due to persistent barriers to new entrants to the market. One of the main challenges to private investment has been the lack of cost-reflective electricity tariffs, which not only limits the competitiveness of renewable projects but also increases off-taker risk and consequently results in higher financing costs for developers. Still, IPP competitive bidding is reserved for almost half of the recently opened 550 MW of wind tenders, and the country's first IPP projects signed a PPA (for 1 GW of geothermal), which suggests that regulatory barriers to private investment may ease as the market grows over the medium term.

Table 1.20 SSA main drivers and challenges to renewable energy deployment

Country	Drivers	Challenges
South Africa	Need for new capacity, supportive policy environment with long-term PPAs, rising power prices.	Cost and pace of grid expansion to integrate new capacity, financial health of the off-taker, weakening macroeconomic environment effects on financing.
Kenya	Robust power demand growth, diversification needs, supportive policy framework, high end-user electricity prices.	Administrative and regulatory barriers, land access and availability, financing costs.
Ethiopia	Fast-growing power demand, excellent resources, long-term targets for renewable capacity.	Market access for IPPs, lack of cost-reflective tariffs, availability of financing for large infrastructure plans.

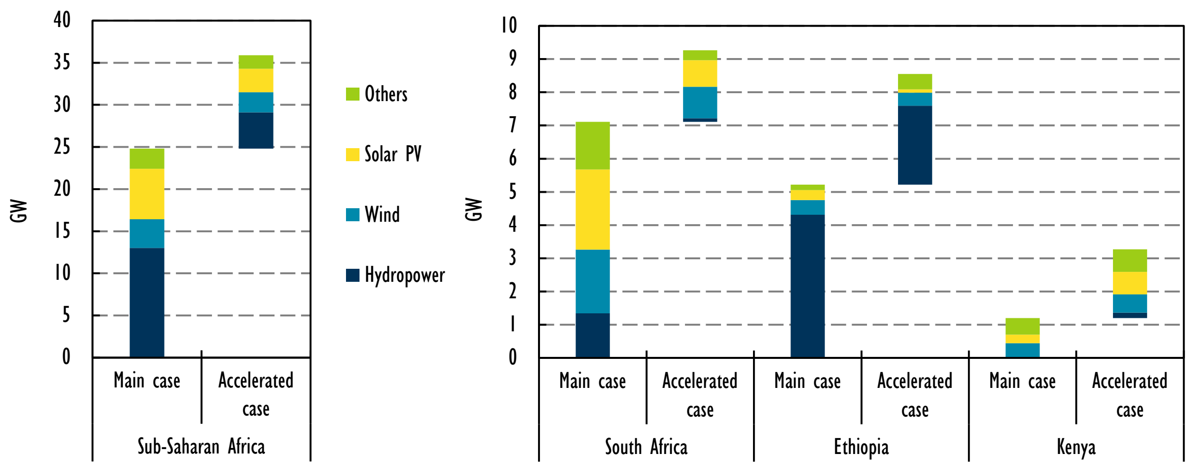
Elsewhere in SSA, **Ghana's** renewable capacity is expected to grow by 500 MW, mostly from solar PV, driven by FITs and the possibility of increased project bankability with the proposed extension of the contract duration to 20 years. Accelerated growth is expected in **Tanzania,** where a revision to the small power producer framework in 2016 is anticipated to result in more favourable conditions for utility-scale deployment**.** Off-grid solar PV deployment should also ramp up from emerging pay-as-you-go solar business models. Still, off-taker risk and the weak grid infrastructure remain a challenge to private investment in both markets and could limit the deployment over the medium term. Utilities in both countries have missed payments to IPPs, further diminishing their creditworthiness, which makes bankability of future projects more difficult. **Nigeria's** renewable deployment has been revised down relative to *MTRMR 2015* after a downward revision to the FITs will likely reduce the overall economic attractiveness of projects. Overall, currency risk, grid constraints and the financial standing of the off-taker remain significant challenges to growth.

Elsewhere in SSA, hydropower is forecast to lead the deployment, expanding by 7.3 GW mainly from large projects in **Angola**, **Cameroon** and **Uganda**. After hydropower, the largest growth over the medium term should come from solar PV, driven both by off-grid applications for rural electrification, isolated industrial consumers, and auctions for grid-connected utility-scale solar PV. In particular, cost-effective solar PV as a means to reduce reliance on hydropower is expected to drive the growth in **Zambia**, where the country's first competitive tenders resulted in the Africa's lowest bids for utility-scale solar PV to date, USD 60/MWh. The tenders were supported by the World Bank's Scaling Solar programme, which offers standardised PPAs and other services. The programme plans to tender an additional 200 MW in Zambia followed by another 200 MW in **Senegal** and 40 MW in **Madagascar**.

Medium-term outlook: Regional accelerated case summary

The possibility of additional renewable capacity expansion in sub-Saharan Africa is substantial, with almost 50% more growth by 2021 under certain policy and market enhancements (Figure 1.30). Faster deployment would require an acceleration of project implementation throughout all development stages such as administrative planning, securing financing and timely grid connections. Increased deployment could be seen if economic and non-economic barriers to attracting new commercial entrants were overcome, particularly strengthening the financial standing of the off-taker and lowering investment risk.

Figure 1.30 SSA renewable capacity additions (2015-21), main versus accelerated case



Ethiopia has the largest upside potential for accelerated renewable deployment due to the size of the large hydropower projects currently under development. Faster progress through hydropower plant construction as well as rapid implementation of recently opened wind tenders could result in Ethiopia's renewable capacity exceeding 11 GW by 2021, a significant increase from the 8 GW expected under the main case. However, this additional expansion requires timely build-out of grid infrastructure.

South Africa's upside potential for accelerated growth is large, given the robust pipeline planned under the REIPPPP, though difficult to quantify given the wide range of uncertainty that stems from many factors that are either unknown or remain to be announced such as the financial close of selected bid winners and the timeline of forthcoming auction rounds. It remains to be seen how changes to the tender design relating to the REDZs, grid connection costs and local content requirements affect the future bidding process and developer interest. Still, South Africa's renewable capacity could be 2 GW higher if some of the aforementioned uncertainties are clarified.

Renewable capacity expansion in **Kenya** could be 1 GW to 2 GW more from accelerated wind and geothermal deployment. Almost twice as much geothermal capacity could be deployed compared with the main case depending on the availability of pre-drilled steam sites for tendering and access to low-cost financing. Wind could be 1 GW higher assuming the grid poses no constraints to the timely commissioning of planned projects. The finalisation of the anticipated net metering scheme could result in additional commercial solar PV deployment given the country's high electricity prices.

Eurasia

Recent trends

In Eurasia, renewable power generation was stable in 2015 in comparison with 2014, reaching 271 TWh in total. Hydropower generation represented over 98% of total renewable output in the region with the Russian Federation (hereafter "Russia") and Belarus dominating statistics. In 2015, Eurasia added 0.4 GW of new renewable capacity, which was a slowdown compared with 1.1 GW added in 2014. With regard to recent deployment trends, renewable additions decreased for a fourth consecutive year, marking a steady slowdown in the region. This slowdown was mainly due to the weak macroeconomic environment and political instabilities in several countries despite excellent renewable resource availability.

Table 1.21 Eurasia net renewable capacity and % in generation (2014 and 2015)

Eurasia		Net capacity additions (GW)					% of electricity generation				
Country	Year	Hydropower	Wind	Solar PV	Other renewables	Total	Hydropower	Wind	Solar PV	Other renewables	Total
Russia	2014	0.8	0.1	0.0	0.0	0.8	17%	0%	0%	0%	17%
	2015	0.1	-	0.1	0.0	0.2	17%	0%	0%	0%	18%
Ukraine	2014	0.4	0.0	0.0	0.0	0.4	7%	1%	0.%	0%	6%
	2015	-	0.0	0.0	-	0.0	5 %	1%	0%	0%	8%
Kazakhstan	2014	-	-	-	-	-	8%	0%	0%	0%	8%
	2015	-	0.1	0.0	0.0	0.1	8%	0%	0%	0%	8%

Note: Rounding may cause non-zero data to appear as "0.0" or "- 0.0". Actual zero-digit data is denoted as "-".

Sources: 2014 capacity data for OECD countries based on IEA (2016a), *Renewables Information 2016*, www.iea.org/statistics/. All other capacity data from multiple sources; see Chapter 2 technology sources for more detail. Generation data based on IEA (2016b), *World Energy Statistics and Balances 2016*, www.iea.org/statistics/.

In **Russia**, 0.2 GW of new renewable power capacity was commissioned in 2015, mainly hydropower (+0.14 GW). No new onshore wind projects were commissioned last year. The halt in onshore wind development is most likely attributed to the weak participation of the technology in the three renewable energy auctions held since 2013, the high local content requirement rule and a more challenging economic situation in the country. In 2015, solar PV capacity expanded by 60 MW and reached 0.1 GW thanks to the commissioning of projects awarded in previous energy auctions. Some geothermal capacity also became operational.

In **Ukraine,** despite political and economic challenges, new renewable capacity came on line in 2015 driven by the needs for energy diversification and security of supply. New capacity additions were led by solar PV, which increased by 20 MW, and onshore wind technologies, which grew by 10 MW, thanks to an attractive FIT. No new hydropower capacity was added in the last year. However, the technology still provided around 85% of the country's renewable generation in 2014.

Kazakhstan added 0.1 GW of new renewable capacity in 2015, taking the total renewable capacity to 2.6 GW. As with other countries in the region, hydropower provides the majority of renewable generation. For example, in 2015, hydropower accounted for almost all renewable electricity generation and 9% of total power generation. In 2015, the first large-scale solar PV power plant (50 MW) was commissioned in the Zhambyl region, representing half of the new capacity added in 2015 (East Time, 2016).

Although no new renewable capacity was added elsewhere in the region, there were a few policy changes in some countries over the last year. Moldova adopted a FIT system in March 2016 to speed up deployment and reach its target of 20% renewable energy in total energy consumption by 2020 (CIS-Solar, 2016). The target was established in its 2013 NREAP and reconfirmed in the country's INDC submitted to COP21 in December 2015. Apart from Moldova, only one other country in the region, Bosnia and Herzegovina, submitted a renewable energy-specific target in its INDC. Overall, most of the Eurasia region countries have taken the first step of renewable energy deployment by establishing some form of renewable energy target. Out of 15 countries in the region, only 4 have not yet established any form of renewable goal: Georgia, Kyrgyzstan, Turkmenistan and Uzbekistan.

Table 1.22 Eurasia countries INDC submissions with renewable energy RE targets and national targets

	National RE targets			INDC RE specific target	
Country	**Target**	**Established in**	**To be reached**	**Target**	**To be reached**
Bosnia and Herzegovina	40% of RE in total electricity consumption	2012	2020	175 MW – Onshore wind 4 MW – Solar PV 120 MW – Small hydro	2030
Moldova	20% of RE in total energy consumption	2013 NREAP	2020	20% of RE in the energy balance	2020

Sources: IEA/IRENA (2016), *Joint Policies and Measures Database for Renewable Energy*, www.iea.org/policiesandmeasures/renewableenergy/; UNFCCC (2016), INDCs as Communicated by Parties, www4.unfccc.int/submissions/INDC/Submission%20Pages/submissions.aspx.

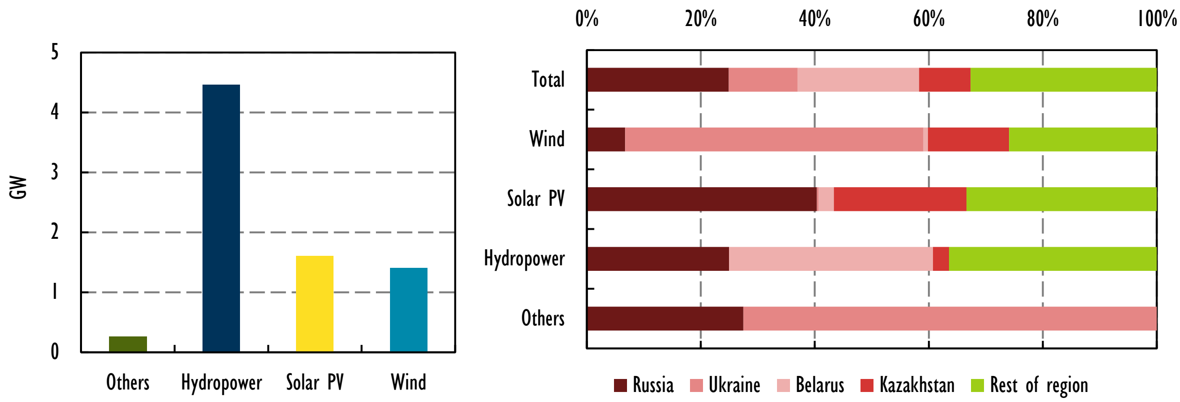
Medium-term outlook: Regional main case summary

In Eurasia, deployment of renewable electricity capacity is expected to remain at a relatively low level over the medium term. Capacity should increase by 7.8 GW, reaching a total of 86 GW by 2021, in line with the *MTRMR 2015* forecast (Figure 1.31). Although hydropower is expected to continue dominating new renewable capacity additions in the region, onshore wind and solar PV deployment should ramp up slowly. The majority of new additions should take place in Russia, Ukraine, Belarus and Kazakhstan, but smaller additions are also expected from Georgia and the rest of the region.

Overall, energy security improvements and supply diversification needs remain the main drivers for energy-importing countries in the region to implement renewable policy frameworks and introduce targets. However, despite excellent resource availability, a combination of weak grid infrastructure, lack of access to affordable financing and regulatory and administrative barriers pose important challenges to the uptake of renewables.

In **Russia**, renewable generation is expected to increase by only 3% to reach 193 TWh over the medium term. With this modest growth, the share of renewables in overall power generation should remain almost unchanged compared with the 2015 level of 18%. Cumulative renewable capacity should grow by 2 GW and reach over 53 GW by 2021. Over the medium term, hydropower should provide the majority of new additions with over 1 GW expected to come on line.

Figure 1.31 Eurasia net renewable capacity additions by technology and country (2015-21)



Solar PV capacity is expected to grow by 0.7 GW driven by tenders. To date, developers have won contracts to build 1.2 GW of solar PV capacity, which was awarded in previous renewable auctions. However, investors did not place any bids in the latest tender held in the first half of 2016. The recent change in the subsidy payment calculation, which lowered the guaranteed project internal rate of return from 14% to 12%, is seen as a major reason behind the lack of interest in the auction. In addition, Russia's current macroeconomic environment poses financing challenges with high interest rates and increasing exchange rate risk. Thus, some already-awarded projects are expected to be either delayed or cancelled (BNEF, 2016).

Onshore wind capacity should increase by only 0.1 GW over the medium term. Russia's project pipeline remains small because stringent local content requirements (LCR) of 25% in 2016, increasing to 65% in 2019, have prevented developers from participating in the previous auctions, as local supply chains remain underdeveloped. Nevertheless, over 600 MW was awarded in the last auction. However, financing challenges mean that only a portion of this capacity may be operational by 2021.

Table 1.23 Eurasia cumulative renewable energy capacity in 2015 and 2021

Total capacity (GW)	2015				2021			
	Total	Russia	Ukraine	Kazakhstan	Total	Russia	Ukraine	Kazakhstan
Hydropower	76.6	51.0	5.9	2.5	81.1	52.1	5.9	2.6
Bioenergy	0.4	0.3	0.1	0.0	0.6	0.3	0.2	0.0
Onshore wind	0.7	0.1	0.4	0.1	2.1	0.2	1.2	0.3
Offshore wind	-	-	-	-	-	-	-	-
Solar PV	0.6	0.1	0.4	0.1	2.2	0.7	0.4	0.4
CSP/STE	-	-	-	-	-	-	-	-
Geothermal	0.1	0.1	-	-	0.1	0.1	-	-
Ocean	-	-	-	-	-	-	-	-
Total	**78.4**	**51.5**	**6.8**	**2.6**	**86.1**	**53.4**	**7.7**	**3.3**

Note: For further country-level forecasts, see online Excel workbook that accompanies this report at www.iea.org/publications/mtrmr/. Rounding may cause non-zero data to appear as "0.0" or "- 0.0". Actual zero-digit data is denoted as "-".

In **Ukraine**, renewable electric capacity is expected to grow by 0.9 GW to reach 7.7 GW by 2021. Deployment will be led by onshore wind (+0.7 GW) and bioenergy (+0.2 GW). Ukraine's energy diversification and security needs drive growth alongside FIT support introduced in 2009. In 2015, the local content requirement rule imposed on renewable projects was softened and became a premium to the base FIT. Projects with the domestic content component of 30% or more will receive 5% or 10% higher remunerations for their electricity generation, provided that installations are commissioned by the end of 2024. This change is expected to lift an important barrier to deployment. Still, political uncertainties and economic risks should remain challenging to renewable deployment over the medium term.

Kazakhstan's renewable capacity is estimated to grow by 0.7 GW to reach 3.3 GW by 2021, led by solar PV (+0.4 GW), onshore wind (+0.2) and some hydropower. This deployment should be driven by the FIT system introduced in June 2014, which grants support for a period of 15 years for all renewable generators. In early 2016, the government amended FIT rules, allowing for annual indexing to the previous year's fixed tariffs in US dollars to reduce exchange rate risk.

Table 1.24 Eurasia main drivers and challenges to renewable energy deployment

Country	Drivers	Challenges
Russia	Regular renewable energy auctions supported by long-term PPAs.	High local content requirements and underdeveloped supply chain for onshore wind. Challenging macroeconomic situation.
Ukraine	Energy security and diversification needs. Renewable targets backed by FITs and variable local content bonus. Lower exchange rate risk by annual contract indexation to the euro.	Political and economic instabilities affecting the investment environment. Grid infrastructure requires upgrades.
Kazakhstan	Renewable targets established FIT provided for 15 years with annual inflation adjustment.	Administrative and regulatory barriers. Availability of low-cost financing.

Medium-term outlook: Regional accelerated case summary

Given the current renewable energy policy framework and recent deployment trends in the Eurasia region, opportunities for an accelerated case remain limited. In **Russia**, higher deployment could be achieved with a faster improvement in the overall macroeconomic environment and softening of the local content requirement in renewable auctions. In **Ukraine**, improvements in the political situation could attract more investors given its robust incentive scheme. In **Kazakhstan**, faster implementation of the auction scheme for renewables, which was announced in early 2016, would speed up deployment.

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14 1. Footnote 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 United Nations, Turkey shall preserve its position concerning the “Cyprus issue”.

2. Footnote 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.

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2. RENEWABLE ELECTRICITY: TECHNOLOGY FORECAST

Highlights

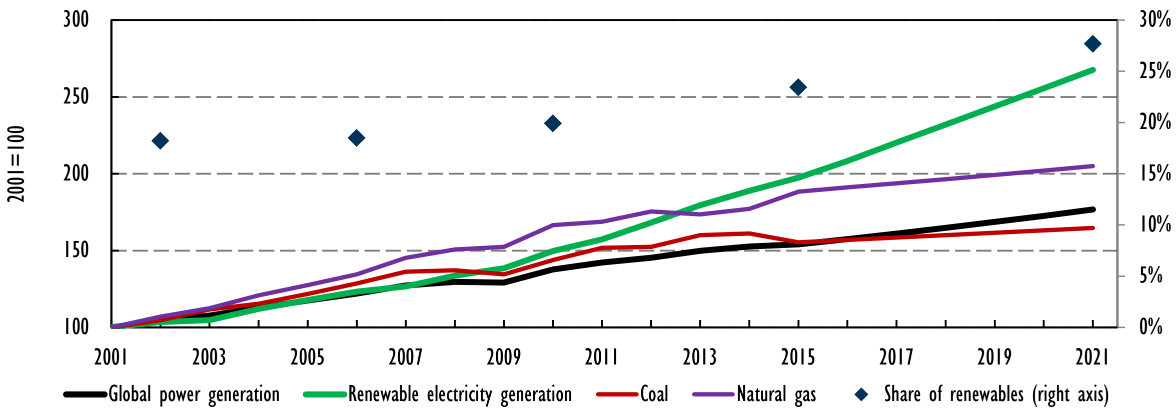
- In 2015, renewable electricity generation grew by an estimated 5% and represented 23% of global power output. Hydropower provided 71% of total renewable electricity, followed by wind (15%), bioenergy (8%) and solar photovoltaics (PV) (4%). Wind (66 GW [gigawatts]) and solar PV (49 GW) together accounted for three-quarters of renewable additions in 2015, followed by hydropower (31 GW).
- Global renewable electricity generation is expected to grow by 36%, faster than any other source; its share in global power output will reach almost 28% in 2021. Non-hydro renewables are expected to lead this growth. Between 2015 and 2021, solar PV generation is forecast to triple and wind to double, while hydropower only grows by 13%.
- Onshore wind is forecast to generate more additional electricity than any other renewable source over the medium term, reaching one-third (733 terawatt-hours [TWh]) of total growth. This is a result of robust deployment (+300 GW) coupled with higher capacity factors from technology improvement and expansion to locations with better resources. As a result, global generation costs are expected to drop another 15% by 2021.
- Solar PV is expected to lead renewable capacity growth over the medium term, expanding by over 300 GW. Utility-scale projects will provide most of the deployment (63%). Since 2011 generation costs for utility-scale projects have declined by two-thirds, and another 25% reduction is expected by 2021. However, recent power purchase agreements (PPA) announcements from new growth markets (Mexico, Chile and United Arab Emirates) indicate further cost reductions are on the horizon with competitive tenders resulting in record-low prices ranging from United States dollars (USD) 30/MWh to USD 45/MWh.
- Hydropower annual additions continue to slow over the medium term due to weaker development of large projects in the People's Republic of China (hereafter "China") because of increasing investment costs and concerns over the social and environmental impacts. Global deployment is forecast to decline by more than one-third between 2015 and 2021 compared to the prior six years. However growth is expected for small hydropower and in pumped storage projects, which can provide flexibility and contribute to the integration of variable renewables.
- The most dramatic generation cost reductions are expected in offshore wind (40%) but grid connections challenges limit deployment (+24 GW). Bioenergy remains the third-largest source of renewable power in 2021, but the absence of strong cost reduction trends means forecast growth over 2015-21 (+35 GW) is expected to be steady compared to the previous six years. Capacity growth for geothermal (+4 GW) and concentrating solar power (CSP) (+6 GW) technologies remains modest. The main challenges to deployment are high generation costs for CSP and pre-development risks for geothermal.
- There is an increasing trend in renewables policies to move from government-set tariffs to policy-driven competitive auctions with long-term contracts. This has improved the risk perception of renewables and will continue to channel competitive financing in the sector. Policies remain important to sustain growth, especially amid lower fossil fuel prices.

Technology deployment overview

- **In 2015, renewable electricity capacity expanded at its fastest pace to date with 153 GW of new grid-connected capacity becoming operational.** Wind power represented over 40% (66 GW) of these additions, followed by solar PV (49 GW) and hydropower (31 GW). Bioenergy, geothermal, CSP for solar thermal electricity (STE) and ocean additions also contributed. For the first time, cumulative renewable electricity capacity surpassed global coal capacity. However, coal remained the dominant fuel for electricity generation, accounting for almost 40% of global power output, followed by renewables.

- **Renewable electricity generation is expected to grow by 36% from an estimated 5 660 TWh in 2015 to 7 672 TWh in 2021,** driven by policies aimed at enhancing energy security and sustainability. The share of renewables in global electricity generation is expected to increase from over 23% in 2015 to 28% in 2021 as renewable power output is anticipated to grow much faster than global power from coal, natural gas and overall electricity generation (Figure 2.1).

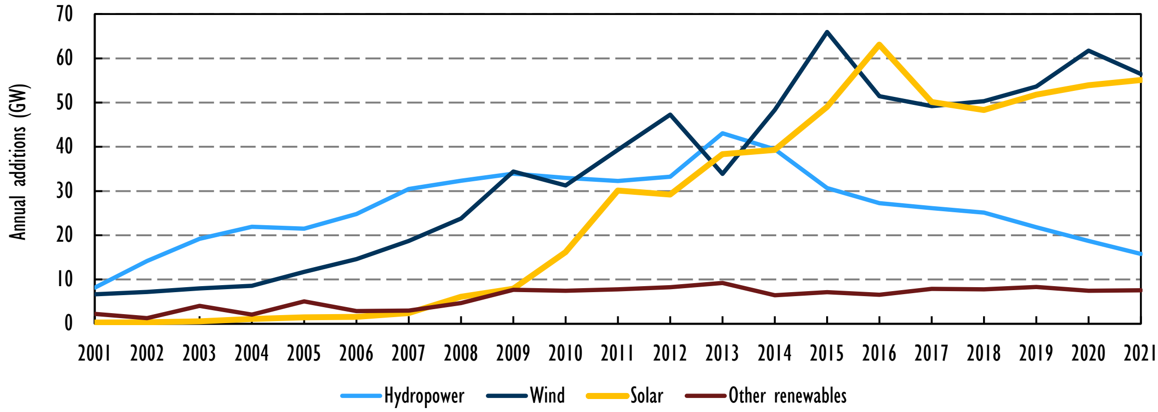
Figure 2.1 Indexed electricity generation by source (2001-21)



Sources: Analysis based on IEA (2016a), *World Energy Statistics and Balances 2016* (database), www.iea.org/statistics/; IEA (2016b), *Medium-Term Gas Market Report 2016*.

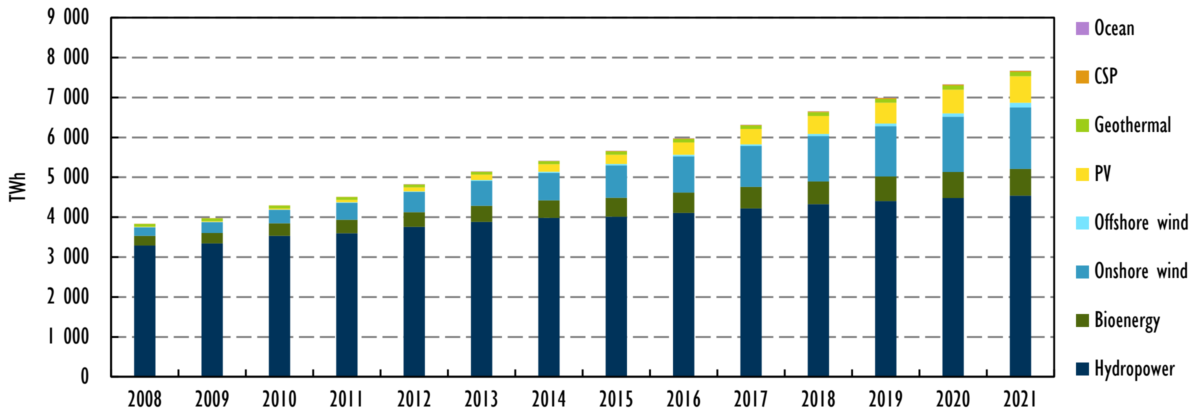
- **Solar PV and wind together represent close to 80% of this additional capacity, driven by support policies and significant cost reductions.** Hydropower provides 16% of renewable capacity additions over the medium term, but its growth slows because fewer large-scale conventional projects are expected to be commissioned in China and projects delays in other countries. Other renewable technologies grow at a slower rate and annual growth trends remain stable over 2015-21. Among them, bioenergy leads the growth, representing 4% of new additions in the medium term, followed by CSP, geothermal and ocean.

Figure 2.2 Renewable net additions to capacity by technology (2001-21)



- **Hydropower remains the largest source of renewable electricity generation, but its overall share in total renewable output decreases from 86% in 2008 to 60% in 2021 (Figure 2.3).** This is largely due to the slowdown of new large-scale projects in China from increasing social and environmental concerns. The expansion of large hydropower is envisaged in other regions such as Asia and Pacific, Latin America, and sub-Saharan Africa, while older markets including Europe, North America and Eurasia should see growth in pumped-storage plants (PSPs), refurbishment and small hydropower.

Figure 2.3 Renewable electricity generation by technology, (2008-21)



Sources: Historical data based on IEA (2016a), *World Energy Statistics and Balances 2016* (database), www.iea.org/statistics/.

- **Onshore wind leads the increase in generation, almost doubling its output with close to 300 GW of grid-connected capacity expected to come on line over 2015-21.** China remains the driver of wind expansion, providing 40% of global additions as grid integration challenges are progressively addressed. With the long-term extension of federal tax credits, the United States (US) is expected to become the second-largest onshore wind market over the medium term, ahead of the European Union (EU), where policy uncertainty, grid integration challenges and increasing social acceptance issues slow growth. However, new capacity additions are strong in emerging markets with excellent resource availability in Latin America, the Middle East and Africa, and are spurred primarily by competitive tenders.

- **Solar PV represents the largest source of renewable capacity growth over the medium term.** Asia, including China, provides over 60% of new additions globally over 2015-21. Utility-scale projects dominate solar PV growth (63%), driven by feed-in tariffs (FITs) in China, the long-term extension of the Investment Tax Credit (ITC) in the United States and state auctions in India. Aside from these three countries, auctions drive the majority of new additions, primarily in Latin America, the Middle East and Africa. The commercial segment is projected to represent approximately 25% of new deployment over the medium term, and residential is projected to represent 12%. The growth in these segments is expected to be driven by FITs in Japan, Europe and China, as well as self-consumption models and state-level incentives in the United States.

- **Bioenergy's** global annual growth in capacity remains stable in the medium term, while generation rapidly expands primarily in Asia. This will be driven by waste-to-energy projects in China, generous FITs in Japan, increasing co-firing activities in Korea, strong agricultural residue resources in India, and energy access needs in Indonesia and Thailand. **Offshore wind's** cumulative capacity more than triples over the medium term, spurred by competitive auctions in Europe and FIT support in China. **CSP** deployment continues to spread to new markets, though deployment expectations have been reduced due to specific market and technology risks, as well as policy frameworks that do not adequately remunerate storage in some markets. **Geothermal** expansion is expected to be stable with new deployment occurring in the United States, Turkey, Indonesia and the Philippines, while drilling and development risks remain challenges for further uptake.

Table 2.1 World renewable electricity capacity and forecast, main and accelerated cases (GW)

	2015	2016	2017	2018	2019	2020	2021	2021 accelerated
Hydropower	1 205	1 232	1 258	1 283	1 305	1 324	1 340	1 369
Bioenergy	105	110	116	122	129	134	140	159
Wind	417	468	517	568	621	683	740	815
Onshore	405	455	502	548	598	652	703	772
Offshore	12	13	16	19	24	31	36	43
Solar PV	225	288	338	386	438	492	547	654
CSP/STE	5	5	6	7	8	10	11	15
Geothermal	13	13	14	14	15	16	17	18
Ocean	1	1	1	1	1	1	1	1
Total	**1 969**	**2 117**	**2 251**	**2 382**	**2 518**	**2 660**	**2 795**	**3 031**

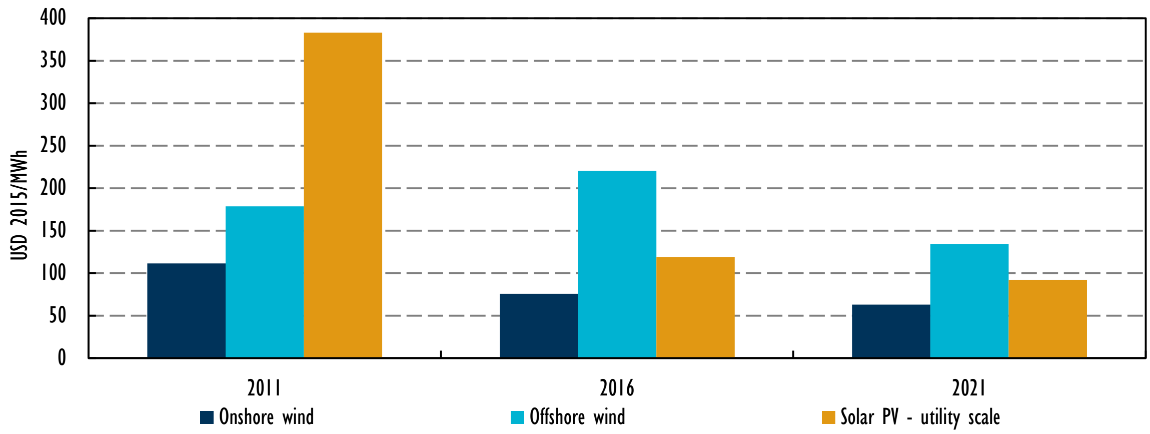
Notes: Capacity data are rounded to the nearest gigawatt and are presented as cumulative installed capacity.

Renewables costs and comparison with fossil fuels

Renewable electricity deployment is expected to be increasingly cost-effective. Costs of renewable generation, especially of solar PV and onshore wind, have been falling dramatically in recent years. The cost-effectiveness of renewable options has improved due to a combination of sustained policy support, technology progress, expansion into newer markets with better resources, and better financing conditions, supported by market frameworks based on price competition for long-term PPAs. From 2010-15, indicative global average generation costs for new onshore wind plants decreased by an estimated 30% on average, and those for utility-scale solar PV fell by two-thirds. Over the forecast period, the *Medium-Term Renewable Energy Market Report 2016* (*MTRMR 2016*) expects generation costs for onshore wind to fall another 15% and those for utility-scale solar PV to drop another 25%. Offshore wind generation costs including all transmission costs are anticipated to decrease by over 40% over the medium term, the largest reduction among all renewables (Figure 2.4).

Overall, fewer economic incentives are needed for some renewable electricity technologies. However, appropriate market design and regulatory frameworks remain critically important to attract investment in capital-intensive renewables and further drive their costs down.

Figure 2.4 Global weighted average LCOEs for new grid-connected projects



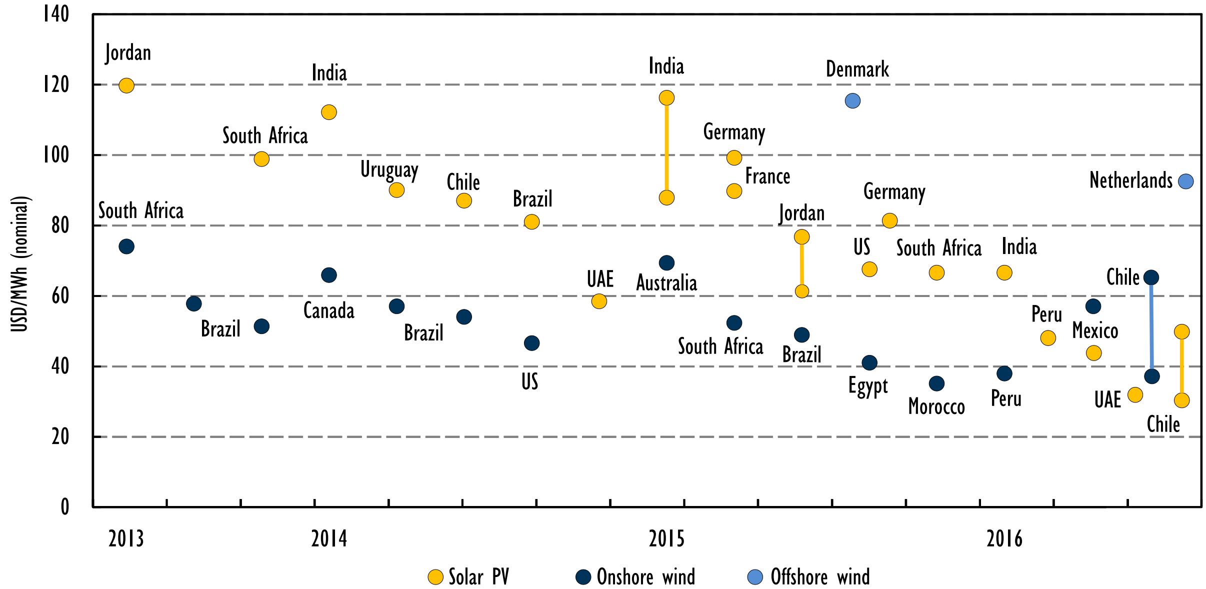
Notes: LCOEs = levelised costs of energy; USD = US dollar; MWh = megawatt-hour. The values are indicative estimates of the global weighted average LCOE based on the *MTRMR* capacity and generation forecasts and may not represent specific developments in a given market. Offshore wind estimates include all transmission costs.

Price discovery through competitive auctions for long-term power purchase contracts has reduced the risk perception of renewables and lowered financing costs. Renewable power policies, especially for utility-scale projects, are moving slowly from government-set tariffs to policy-driven competitive auctions with long-term PPAs. While both schemes aim to provide a long-term revenue certainty that aims at decreasing investment risk premiums, the private sector's involvement in price discovery has not only resulted in lower prices in some markets but also increased competitive pressure throughout upstream and downstream supply chains. The increasing involvement of equipment manufacturers, financers, insurance companies, operation and maintenance (O&M) service providers, and legal firms in the preparation of renewable competitive auction/tender schemes has resulted in better understanding and management of project risks by different stakeholders.

Recent announcements of long-term remuneration contract prices from PPAs awarded through competitive bidding for solar PV and wind show that a further acceleration in price reductions is possible for projects commissioned over 2016-21 (Figure 2.5). Some of these contract prices may reflect different market-specific factors such as price escalations, special low-cost financing, exceptional capacity factors, and additional subsidies for land and grid connection, which make comparisons among different markets (or even different projects within the same market) difficult. In addition, delivered project costs may ultimately be different from those reported at the time of the auction or the signature of the PPA. Still, these auction results signal a clear acceleration in the reduction of some renewable generation costs. For instance, winning bids for solar PV declined by

30% in India in just one year, both wind and PV bids declined by the same amount in South Africa over two years, and solar PV prices almost halved in Jordan between 2013 and 2015. In Chile, the average awarded contract price during the energy auction held in August 2016 was USD 48/MWh, 60% lower than the previous auction held in 2015, with solar PV developers winning contracts as low as USD 30/MWh.

Figure 2.5 Recent announced long-term remuneration contract prices for renewable power by date of announcement and to be commissioned over 2016-21



Notes: Values reported in nominal USD; UAE = United Arab Emirates. US values are implied excluding tax credits; US wind value corresponds to Interior Region for commissioned projects in 2014. Other values reported correspond to projects that are expected to be commissioned over 2016-19. Offshore wind bid prices include transmission costs, which are estimated.

A number of countries launching an auction for the first time in 2015-16 immediately achieved record low prices, as low as USD 35/MWh for wind onshore in Morocco and USD 30/MWh for solar PV in Dubai. While offshore wind prices remain relatively high in absolute terms, recent tender results for projects expected to come on line in 2019-21 in Denmark and in the Netherlands show 40-50% decreases compared with prices of the Contract for Difference (CfD) auctions held in 2014 in the United Kingdom (UK).

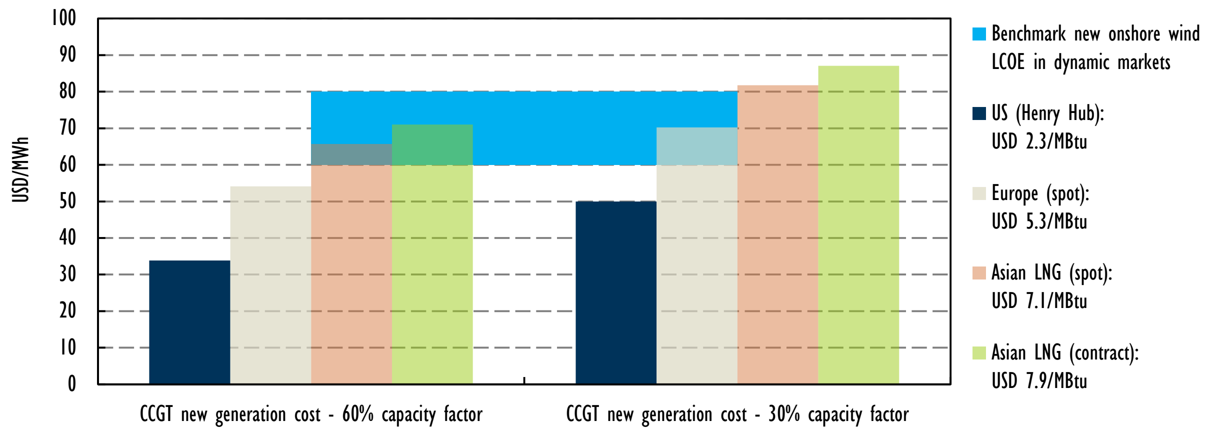
Auction results and deployment plans suggest that new onshore wind projects can be built today in a number of countries for USD 60/MWh to USD 80/MWh, while new PV projects can be contracted at USD 80/MWh to USD 100/MWh, with the best case for wind and solar PV at around USD 40/MWh. The most recent auctions suggest that new benchmark generation prices over the medium term in countries with excellent resources and good financing conditions could further drop to USD 45/MWh to USD 65/MWh for onshore wind and USD 60/MWh to USD 80/MWh for solar PV, with possible best cases well below these levels for both technologies.

While levelised renewable electricity generation costs might be comparable to or even lower than new-built fossil fuel alternatives in some countries, an assessment of their competitiveness

requires a closer look at the value of electricity. While these benchmark cost ranges are increasingly comparable with generation costs from new gas power plants in some countries (Brazil, Uruguay, Chile and South Africa), fuller competitiveness assessments would need to quantify integration costs, as well as the value of the injected electricity to the system, according to the load profile of demand and the time and location of generation. On the other hand, the negative environmental externalities associated with fossil fuel generation and the potential hedge value of renewables against fuel price volatility would also need to be accounted for.

Over the medium term, deployment of renewable electricity is largely sheltered from reduced fossil fuel prices by policy measures already in place. Over the last two years, weakening supply and demand fundamentals and lower oil prices have resulted in lower gas prices and strong gas price convergence across different regions. Well-supplied gas markets are forecast to keep global spot prices under pressure over the next few years (IEA, 2016b). However, benchmark LCOEs and contract prices for onshore wind, utility-scale solar PV and some bioenergy technologies can be increasingly comparable with generation costs from new natural gas plants in some markets, even with the lower oil and gas prices (Figure 2.6). However, it is important to note that investment decisions in new power-generating capacity necessitate a complex decision-making process, not made only based upon LCOEs, and strongly dependent on specific market and regulatory frameworks. Despite current lower fossil fuel prices, an investment in new capacity needs to take into account a number of risks. The price volatility of fuel, future possibility of tighter environmental regulations, risk of lower-than-planned capacity factors due to the merit-order effect and overcapacity in countries with stagnating demand growth, and downward pressure on wholesale prices for the same reasons remain important risk premiums to invest in new fossil fuel generation that would operate for 20-30 years. On the other hand, without a simultaneous increase in system flexibility (grid reinforcement and interconnections, storage, demand-side response and other flexible supply), variable renewables are more exposed to the risk of losing system value at increasing shares of market penetration, as wholesale prices are depressed precisely when there is an excess of wind and solar production versus demand.

Figure 2.6 LCOE of gas-fired generation at January 2016 gas prices versus onshore wind benchmark costs



Notes: MBtu = million British thermal units; LNG = liquefied natural gas; CCGT = combined-cycle gas turbine. LCOE CCGT assumes efficiency of 60%; 7% discount rate; no carbon price is assumed; capital cost and O&M assumptions based on IEA and NEA (2015), *Projected Costs of Generating Electricity 2015*.

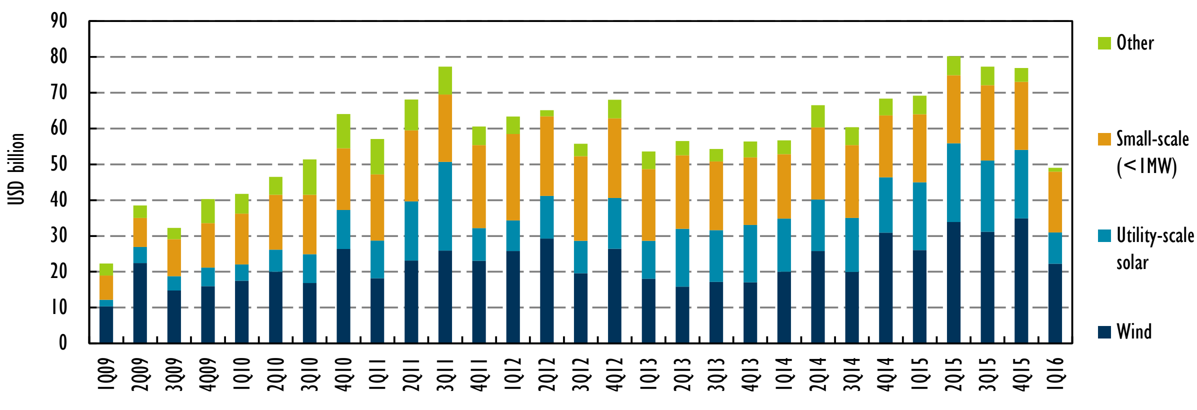
Renewable power investment and financing trends

In 2015, renewables represented around 70% of new investment in power generation capacity. Annual investment in renewable power stood at USD 288 billion in real terms, down 1.5% from 2014. This small year-on-year (y-o-y) decline in investment, despite the 15% growth in annual capacity additions, is a result mostly of technology progress and cost declines of the most dynamic renewable technologies (onshore wind and solar PV). Onshore and offshore wind combined accounted for over 35% of total investment, followed by solar PV for one-third. Hydropower represented over 20%, though its share has been declining, while other sources (bioenergy, CSP, geothermal) accounted for nearly 10% of investment.

The required cumulative investment in renewable power capacity that is forecast in *MTRMR 2016* main case is estimated around USD 1 450 billion in real terms over 2015-21, or USD 242 billion annually on average. Average annual investment levels going forward are forecast to be lower than investment in both 2015 and 2014. This decrease emerges as a result of 1) a trend of relatively flat yearly capacity additions as a result of declining conventional hydropower growth mainly in China; and 2) expected cost reductions for onshore wind, offshore wind and solar PV over the medium term. Wind and solar PV together account for more than two-thirds (around USD 1 040 billion) of required investment to commission based on this report's capacity projections. Hydropower (USD 250 billion) and bioenergy (USD 120 billion) are expected then to follow.

Recent asset financing trends are in line with the *MTRMR 2016* forecast for solar PV and wind over the medium term (Figure 2.7). Unlike investment figures, which represent actual turnover of the capital stock in a given year, the latest financing figures indicate the potential value of renewable power that will be commissioned within a one- to four-year time horizon. Renewable financing activity has grown significantly since early 2014, despite the decreasing trends of both fossil fuel prices and costs for onshore wind and solar PV. However, the decline in the first quarter of 2016 is partly due to financing and project commissioning rushes in 2014-15 in the United States and China. In the United States, some investors were expecting the expiration of federal tax credits in 2015 (which were eventually renewed in December 2015) and in China, wind developers rushed to finance and commission their projects before the FIT cuts in January 2016. In addition, lower renewable financing activity in Latin America due to the current macroeconomic environment also contributed to this downward trend.

Figure 2.7 Renewable power capacity asset financing (2009-16)



Notes: MW = megawatts. Clean Energy Pipeline (CEP) database takes into account only hydropower projects less than 50 MW.

Source: Analysis based on CEP (2016), *Investment Dataset for the IEA.*

Hydropower

Technology, manufacturing and cost developments

Hydropower is currently the largest source of renewable power in the world, with potential for the technology to further contribute to global clean electricity supply. Hydropower is a mature technology, yet continues to evolve. Recent trends are focusing on maximising efficiency and adapting the technology to provide system flexibility and stability, especially where the share of variable renewables is increasing rapidly. In particular, reservoir hydropower and PSPs can provide valuable system services, but inadequate market design and regulatory barriers can prevent these plants from reaching their full potential.

Hydropower technologies can be classified into many different categories depending on site characteristics, plant size and technology type. Definitions are not often mutually exclusive and vary among markets and industry stakeholders. For the purpose of this report, hydropower plants will generally be referred to as those with storage capabilities (reservoir and PSPs) and those without (run-of-river), taking into account that the latter may still have a small reservoir or pondage. PSPs can be either pure or mixed, which further complicates categorisation. Hydropower classification by size remains challenging as the cut-off between large and small usually depends on country-specific definitions and whether the accounting is made at plant or unit level. In this report, large hydropower refers to plants greater than 10 MW while small hydropower refers to plants less than or equal to 10 MW.

Hydropower investment costs span a wide range because they are extremely site-specific. Many of the technical parameters such as hydraulic head and flow rate dictate equipment choice while construction costs are based on geologic and hydrologic characteristics that are unique to each river basin. Equipment costs and civil works together can represent as much as 75% to 90% of total investment costs, although wide ranges in these shares exists and vary by plant size (IRENA, 2015). The remaining costs, often called balance-of-system costs, include feasibility and socio-environmental assessments, grid connection and transmission build-out costs, civil engineering and services, and licensing and permitting, among others.

In 2015, investment costs for new-build large hydropower projects typically ranged from USD 1 300 per kilowatt (kW) to over USD 2 500/kW, and for small hydropower the range was between USD 2 030/kW to over USD 3 500/kW, although costs outside these ranges have been observed (IEA, 2016c). For both sizes, costs in China, Eurasia and the Russian Federation (hereafter “Russia”) fell at the lower end of the range while those in North and Latin America (excluding Brazil) fell at the higher end. While investment costs in many markets have been relatively stable in recent years, costs for large hydropower in China have started to rise since 2013, in part due to gradually increasing costs in labour and materials (BNEF, 2015a). In addition, increases in resettlement expenses, taxes paid to local governments and construction of transmission lines for some projects located far from demand centres also contributed to rising costs in China. Investment costs for PSPs also span a wide range due to site-specificity with ranges assessed between USD 500/kW and USD 2 000/kW (IEA and MME, 2012). Costs for variable speed turbines, which can reach up to USD 3 200/kW in the United States (DOE Office of Scientific and Technical Information, 2016), tend to be higher than for fixed-speed.

Over the medium term, substantial declines in hydropower investment costs due to innovation are not expected for large conventional hydropower given that the technology is relatively mature. With efficiency maximised for most components, equipment manufacturers are placing more focus on developing equipment that will help new and existing projects provide more flexibility and stability to the power system, a role well-suited for storage hydropower. In practice, this means developing technology that will allow plants to operate over a wider variety of load profiles where faster ramp-ups and -downs are required in shorter periods of time, particularly to accommodate an increasing penetration of variable renewable technologies. Such is the case for PSPs, where technology innovations continue to improve the performance and applications for both variable-speed pump-turbines and ternary machines. In particular, cost reductions are expected in the technologies for synchronous motor-generators with full-power converters (HEA, 2015). Other developments are directed towards reducing the environmental impacts on fish and water quality, such as fish-friendly, oil-free and/or aerating turbines (IEA and MME, 2012).

Globally, LCOEs for large conventional hydropower are estimated between USD 20/MWh and USD 150/MWh depending on, among other things, size, the cost of capital and capacity factors (IRENA, 2015). The design of the plant to operate either as base-load or peaking can result in capacity factor ranges from 20% to 90%, which significantly influence the LCOE. Lower weighted average generation costs have been observed for new projects built in regions with untapped economic potential, whereas higher costs were observed in regions where much of the lower-cost resources have already been exploited, such as in Europe and North America (IRENA, 2015).

Over the medium term, substantial declines in LCOEs due to equipment cost reductions are not expected for new-build large conventional hydropower. Further reductions in generation costs will likely come from decreasing balance-of-system costs, O&M, and financing as well as minimising project lead times and increasing the operational life. Advancements continue to be made in technologies that help increase the lifetime of the parts and lower the maintenance requirements such as in new types of abrasion-resistant coatings and developing stronger and more corrosion-resistant materials (HEA, 2015). Such improvements can also increase the economic potential of some sites as they allow projects to operate in flows with a wider variety of silt profiles.

Since hydropower projects are highly capital-intensive, financing conditions will continue to play a key role on the LCOEs over the medium term. Recent financing trends tend towards risk-sharing between the private and public sector. Projects that illustrate regional co-operation, where multiple countries benefit from the power, are likely to find more favourable financing going forward. For example, the 150 MW Ruzizi III, a public-private partnership (PPP) project among Rwanda, the Democratic Republic of Congo and Burundi, reached financial close at the end of December 2015 with favourable financing from the African Development Bank.

Still, the economic attractiveness for large hydropower going forward is not without challenges. In India, cost over-runs from long drawn-out environmental assessments, resettlement issues and unexpected geological conditions have challenged the competitiveness of large hydropower with coal (PwC and ASSOCHAM, 2016). An increasingly unpredictable climate and inadequate precipitation levels can result in lower capacity factors, which increase the risk of incurring financial losses. Recently hydropower operators in Brazil incurred losses as a result of being forced to purchase more expensive electricity from the spot market; otherwise they would not have been able to fulfil their power supply contracts because their generation was restricted to conserve water during recent droughts.

Globally, LCOEs for small hydropower are estimated from USD 30/MWh to over USD 230/MWh (IRENA, 2015; IEA and MME, 2012). Cost reductions for small hydropower will likely focus on continuing to develop standardised products for smaller plants. Technology improvements in variable-speed bulb turbines that operate in a variety of low-head conditions should also allow more sites to become economically attractive (HEA, 2015). Reducing the cost and time required for permitting and licensing for small hydropower projects in some markets and easier access to affordable financing would also decrease generation costs in several markets (Liu, Masera and Esser, 2013).

Refurbishment projects may become increasingly economically attractive over the medium term in markets with ageing fleets because of the improved performance relative to the low investment cost required. Investment costs are estimated at USD 500/kW to USD 1 000/kW with LCOEs estimated in the range of USD 10/MWh to USD 50/MWh, depending on the project (IEA and MME, 2012; HEA, 2015). Refurbishments can include repowering, upgrading parts, uprating capacity or rehabilitation of the site as well as modernisation and retrofitting existing sites to incorporate new technologies that increase the plant's ability to provide flexibility to the grid.

It should be noted that the LCOE is only one metric for assessing hydropower costs, and it does not capture the real value of electricity that storage hydropower technologies bring to the system such as flexibility, firm capacity and storage ability. An increasing penetration of variable renewables requires a system that can respond to fluctuations in supply and demand, and balance loads quickly. Technologies such as reservoir hydropower and pumped storage that can regulate output and ramp up and down quickly will be needed for such a system to provide ancillary services such as quick start, black start, spinning reserve, frequency response and voltage regulation, among others. Despite the potential to meet the demand for such services, market designs that fail to adequately value flexible generation or do not remunerate ancillary grid services may challenge the economic attractiveness of storage hydropower and can limit future deployment. For PSPs in particular, older business models based strictly on energy arbitrage are no longer viable in markets where lower electricity prices are squeezing generators' margins. In such markets, PSPs are becoming less economically attractive in the absence of products that allow grid services to be monetised. Other challenges to deployment include paying double grid fees in some markets, for both pumping and generating, which further deters investment (HEA, 2015). Less liberalised markets that have yet to incorporate time-differentiated pricing or tariff structures (peak, off-peak) can also limit reservoir hydropower's potential as dispatchable generation able to meet peak demand.

The true economic value of some hydropower projects can be difficult to assess, as oftentimes the dam associated with the plant is used for water-related services other than electricity generation that may not be monetised, such as irrigation, flood control and municipal water supply. The value of these multipurpose services can be difficult to quantify and assess relative to the cost of the infrastructure, which may underestimate the true value of a hydropower project. Conversely, trade-offs between power generation and other water services, particularly when multiple stakeholders are involved, can occur and affect the project economics. To this end, the water availability and management are seen playing an increasing role in future hydropower development.

Market status

Global hydropower net additions, including PSPs, fell in 2015, with only 31 GW commissioned in 2015 compared with the peaks seen in 2014 (39 GW installed) and 2013 (43 GW installed). This downward global trend is largely influenced by China, which installed approximately 15 GW in 2015, almost half of the world's new additions, but nearly 40% less than in 2014. Approximately 40% of the rest of the deployment was concentrated in ten countries, each adding between 500 MW and 3 GW: Brazil, Canada, Turkey, India, Iran, Viet Nam, Malaysia, Lao People's Democratic Republic (Lao PDR), Colombia, and Peru.

At the end of 2015, global cumulative installed hydropower capacity stood at 1 205 GW with an estimated 80% of large conventional hydropower (>10 MW, excluding PSPs), 11% of PSPs, and 6% of small conventional hydropower (<10 MW, excluding PSPs). However, there is some uncertainty associated with these estimates as the numerous configurations and complexities of hydropower plants make tracking and classifying the global fleet into distinct categories difficult. Hydropower market segment data are highly sensitive to classification details that are not always uniformly available across markets during data collection, such as whether or not data is aggregated at the unit level or plant level or how mixed PSPs are treated.

In 2015, approximately 2.6 GW of PSPs were added, bringing the total capacity to almost 140 GW, around 11% of the global fleet, although some estimates for cumulative installed PSP capacity are as high as 148 GW (REN21, 2016; IHA, 2016). Differences in PSP figures can arise from difficulties in monitoring the different configurations as well as the lag time between construction finish, testing mode and full commercial operation. For example, China's 1.2 GW Qianyuan became operational in November 2015 although some of the turbines may not reach full generation speed until 2016. The 430 MW Reisseck II in Austria began testing in 2015 and will be fully commercial by late 2016. Over 80% of cumulative installed PSPs are located in Europe, Japan, China and the United States. However, activity is spreading to other regions. In 2015, Iran commissioned the Middle East's first PSP, the 1 GW Siah-Bishe, and in early 2016 South Africa completed the first two units of Ingula 1 totalling 666 MW.

Table 2.2 Hydropower capacity and forecast by region (GW)

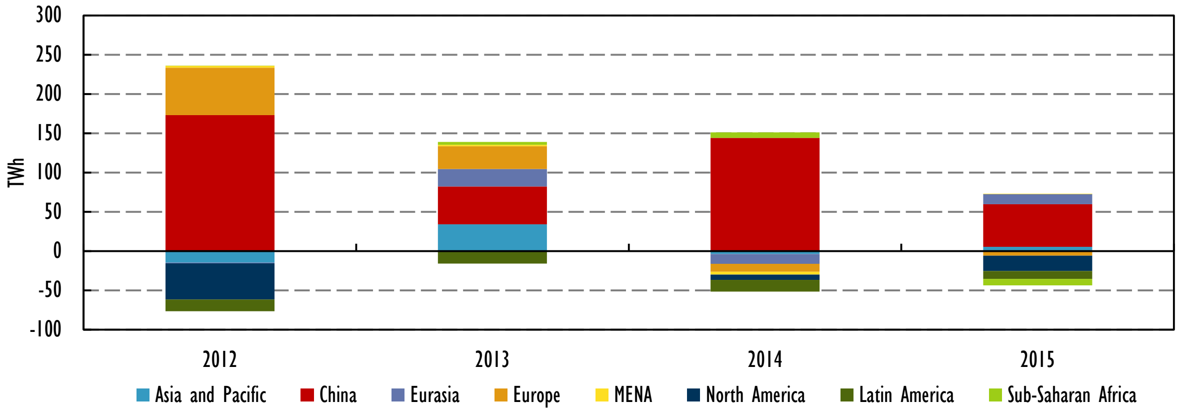
	2014	2015	2016	2017	2018	2019	2020	2021
North America	190	193	193	194	195	195	196	196
Latin America	157	161	166	171	176	180	182	184
Europe	227	230	233	235	237	239	240	241
Asia and Pacific	176	181	186	191	196	201	204	208
China	304	319	330	339	348	356	363	368
Eurasia	76	77	77	77	78	79	80	81
MENA	20	21	22	22	23	24	24	25
Sub-Saharan Africa	23	23	25	28	30	32	34	36
Total	**1 174**	**1 205**	**1 232**	**1 258**	**1 283**	**1 305**	**1 324**	**1 340**

Note: MENA = Middle East and North Africa.

Sources: Historical data based on IEA (2016d), *Renewables Information 2016* (database), www.iea.org/statistics/; Platts (2016), *World Electric Power Plants Database*; IHA (2016), *Hydropower Status Report 2016;* IJHD (2015), *2015 World Atlas and Industry Guide*; IRENA (2016b) *Renewable Capacity Statistics 2016*.

Hydropower continued to be the largest source of renewable power in 2015 with an estimated 4 012 TWh produced, generating approximately 17% of the world's total power generation. China generated the most, around 1 119 TWh or 30% of the world's hydropower, followed by Canada, Brazil and the United States. However, the estimated y-o-y increase in global hydropower generation was only 30 TWh in 2015, 70% less than the additional amount generated in 2014, due to lower-than-average precipitation levels in some countries. Some regions have experienced multi-year droughts beginning in 2012, such as Brazil, Venezuela, Colombia and western parts of the United States, which led to lower reservoir levels and declines in hydropower generation continuing into 2015. The El Niño weather phenomenon, which causes either above- or below-average precipitation levels depending on the region, has added to the volatility in country-level generation figures over the last year.

Figure 2.8 Hydropower annual change in generation by region (TWh)



Sources: Historical generation from IEA (2016a), *World Energy Statistics and Balances 2016* (database), www.iea.org/statistics/.

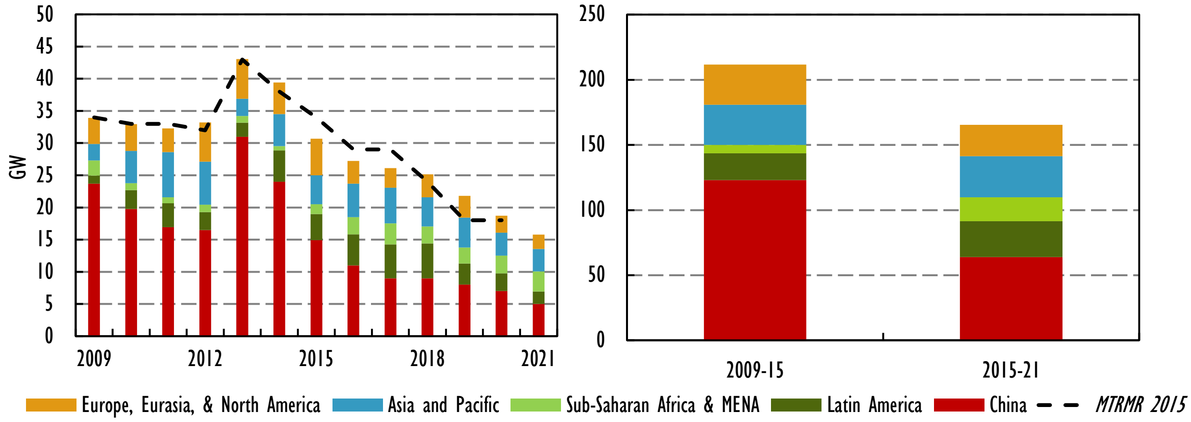
Market outlook: Main case summary

Hydropower capacity is expected to grow 135 GW over the medium term, reaching 1 340 GW by 2021. More than half of the expected global growth comes from three countries: China (+49 GW), Brazil (+16 GW) and India (+10 GW) as large hydropower projects under construction are completed in the near term. However, concerns over the cost and impacts of such projects have limited new-build construction in these markets and, as a result, cause global annual additions to slow by 2021 (Figure 2.9). Overall, fewer global additions are expected over 2015-21 compared to the previous six years owing to the large influence of China's slowdown (Figure 2.9). China's role in the global market is seen declining over the medium term, accounting for less than 40% of new-build hydropower over 2015-21, compared with the 60% market share it held during the previous six years. Instead, growth is seen moving to markets in Southeast Asia, Latin America and sub-Saharan Africa for large hydropower projects and to older markets such as Europe, North America, and Eurasia for refurbishment, PSPs, and small hydropower.

Large conventional hydropower projects (>10 MW) are still expected to dominate the forecast; however small hydropower, driven by government support in the form of auctions, FITs, and rural electrification in some cases, is seen growing in Eastern Europe and Eurasia, as well as in Asia and Brazil. PSP growth is expected to continue into 2016 from units commissioned in South Africa, Austria, Switzerland and Portugal. China is expected to lead PSP deployment over the medium term, followed by Europe. These regions combined make up approximately 80% of PSP capacity currently under construction. However on an annual level, Europe's deployment slows by 2021 as the economic attractiveness becomes increasingly challenged under the current market design.

China is expected to add almost 50 GW of hydropower capacity over 2015-21, a third from PSPs alone, reaching a total of 368 GW by 2021. However, annual deployment is expected to slow significantly over the medium term compared with its peak in 2013, when 31 GW was installed, as concerns over the social and environmental impact, grid integration challenges, and a sluggish power demand growth have challenged the economic attractiveness of large hydropower and created a smaller pipeline of multi-gigawatt projects under construction. By 2021, annual additions are expected to level off at 5 GW, down from 15 GW in 2015. However, faster commissioning of two mega projects (Bhaetan, 16 GW, and Wugonde, 10 GW) could alter this trend over the medium term.

Figure 2.9 Hydropower annual net additions (left) and cumulative additions to capacity (right)



While ambitious 2015 targets under the 12th Five-Year Plan (FYP) and growing power demand drove much of the large hydropower deployment to date, China's outlook remains uncertain as electricity consumption growth slows, the risk of overcapacity rises, and the new 2020 hydropower targets under the 13th FYP remain to be finalised. The targeted split between conventional and PSP, if such a differentiation is made, is particularly unclear, although an increasing penetration of variable renewables and a new incentive suggest a growing PSP market. Nonetheless, this report expects PSP to grow 50% (14 GW) by 2021 at a rate of 2 GW to 2.5 GW per year, though deployment could be higher depending on how it is prioritised in larger long-term energy plans and if any market reforms affect the attractiveness of the PSP incentive.

Installed hydropower capacity in the Asia and Pacific region is expected to grow 15% by 2021, relative to 2015, reaching 208 GW and surpassing North America to become the third-largest region for cumulative installed hydropower capacity (behind China and Europe). **India**, in particular, is expected to add 10 GW, less than the amount planned in recent years. Much of the planned capacity has had prolonged periods of development and difficulty starting construction due to disputes among local governments sharing the same river basin, grid integration challenges, and stop-and-go approval processes regarding resettlement and environmental impacts. As a result, the targets for installed hydropower capacity in the last two FYPs have been missed (PwC and ASSOCHAM, 2016). Meanwhile, India's growing demand for power, among others in the region, and the opportunity for regional power trade are driving deployment in other markets, which should be facilitated by the newly commissioned transmission lines between India and Nepal, and Indonesia and Malaysia in early 2016 (IHA, 2016). Cross-border trading is one of the main drivers of deployment in Bhutan, Lao PDR and Nepal, which are seen adding more than 6.5 GW collectively over the medium term. Pakistan and Indonesia are each seen commissioning 2.7 GW and 1.6 GW respectively by 2021 to meet their growing demand.

Sustained hydropower growth is expected in Latin America with the region adding over 23 GW over 2015-21 with almost 70% (16 GW) coming from **Brazil** alone. Large hydropower drives the bulk of Brazil's growth, which is expected to peak halfway through the forecast period as units from several large multi-phase projects nearing completion are commissioned. However, the annual deployment pattern is highly sensitive to project-specific events that can delay commissioning such as court-ordered construction freezes, approval cancellations and licence suspensions, which have already beset some of these large projects. In April 2016, the licensing for Brazil's 8 GW Sao Luiz do Tapajos dam was suspended over the environmental assessment results of the project's impact on the local community and could delay plant operations. By 2019, Brazil's annual growth is expected to slow and taper off by 2021 as the pipeline for new-build large hydropower under construction dwindles. Nevertheless, there is potential for smaller hydropower growth in Brazil, as over 1 GW of small to medium-sized plants have been tendered since 2012. In the remaining countries, increased interconnection and the potential for regional power trade are seen as drivers for growth. Over 7 GW is expected from Peru, Colombia, Ecuador, Chile and Bolivia, which are part of the Andean Electrical Interconnection System (SINEA) project where two transmission lines are under development to connect the markets.

Sub-Saharan Africa is expected to increase its role in global hydropower deployment from 1% over 2009-15 to 10% over the medium term by adding 13 GW through 2021, driven by new capacity needs to meet fast-growing power demand. The largest additions are expected to come from **Ethiopia** (+4.3 GW) and **Angola** (+2.5 GW). **South Africa** is expected to complete the continent's largest PSP project by 2017, Ingula III, which when completed will be approximately 1.3 GW. Other large additions are expected to come from **Zambia**, **Uganda** and **Mozambique**. However, recent droughts and an over-reliance on hydropower have raised concerns about diversification. Uneven precipitation levels across the region have created surpluses in some hydropower plants and droughts in others. To this end, cross-border projects are increasingly seen as essential to meeting regional power demand, particularly to help balance the increasing variation in precipitation levels among countries.

Europe is expected to add 10 GW over the medium term, driven by large new-build projects in **Turkey** and by PSPs in the rest of Europe. With over 3 GW currently under construction, Turkey is expected to account for almost 35% of Europe's hydropower growth over the medium term, driven by increasing power demand and government plans to further attract private developers to exploit the remaining untapped economic potential (IJHD, 2015). However, projects in the east of the country face an increasing risk of delay from the recent geopolitical situation. Excluding Turkey, 45% of Europe's hydropower deployment over the medium term is expected to come from PSPs, driven by large projects nearing completion in **Austria**, **Switzerland** and **Portugal** where a construction pipeline of over 4 GW has emerged due to a well-suited topology for PSPs and a need to balance Europe's increasing penetration of wind and solar PV. However, falling electricity prices and insufficient remuneration for the ancillary grid services PSPs provide risk limiting further PSP development going forward. Limited economic potential remains for greenfield large hydropower projects in Western Europe, and outside of PSPs, the future market growth is likely to be focused on refurbishment and small hydropower. A majority of the remaining 2 GW in the construction pipeline is a split between large upgrades at existing facilities, repowering or modernisation, and smaller projects less than 50 MW. Small hydropower growth is expected particularly in the Balkan countries, where untapped potential coupled with government support policies in **Macedonia**, **Montenegro** and **Serbia** have created a pipeline of planned projects. Though a number of Western European countries also have FITs for small hydropower plants, it is unknown if support levels are sufficient to spur additional deployment in the region. Meanwhile, **France** opened the country's first tender for small hydropower in 2016.

Stable annual growth is expected in North America, Eurasia and the Middle East over the medium term, when each region is expected to add approximately 4 GW over 2016-21. **Canada** is expected to continue to lead deployment of large hydropower in North America by adding more than 2 GW while **Russia**, **Georgia** and **Belarus** are each expected to add over 1 GW by 2021. **Iran,** the only country in the Middle East where hydropower deployment is expected over the medium term, is seen adding just under 4 GW. The **United States**, which has the second-largest hydropower fleet in the world behind China, is expected to deploy almost 1 GW over the medium term. Most of the deployment is expected to be refurbishments of pre-existing hydropower projects or transformation of pre-existing water management structures into hydropower plants; these transformations are supported by the appropriation of funds for the third consecutive year of Section 232 of the Energy Policy Act of 2005, the Hydroelectric Incentive Program, which allows generators to receive up to USD 1.80/MWh (USD 2005) (USD 2.30/MWh [USD 2015]) for hydropower plants built on existing dams completed before 2005.

Hydropower is expected to remain the largest source of renewable power over the medium term, accounting for over 60% of renewable generation and 16% of total generation by 2021. Hydropower generation is forecast to reach 4 540 TWh by 2021, although exact figures will depend on multiple factors that affect capacity factors such as rainfall patterns, reservoir levels, and how the economic outlook and resulting impact on power demand affects specific markets' fleets. The El Niño weather pattern characterised by heavy rainfalls and droughts unevenly distributed across the world has caused a surplus of rainfall in some regions and exacerbated drought conditions in others. Northern parts of Brazil, California and Ethiopia are likely to experience increased capacity factors and generation relative to previous years, while other parts of Latin America and sub-Saharan Africa are likely to face a shortage of hydropower generation. In Tanzania, for example, hydropower stations were shut down in early 2016 to avoid a potential collapse of the dam from dangerously low reservoir levels. The risk of overcapacity in Brazil and China over the medium term as power demand slows also adds uncertainty to the hydropower generation forecast as it remains to be seen how generation from new hydropower plants will be dispatched relative to seasonal water availabilities and the growth coming from other technologies such as solar PV and wind – and, in China, coal.

Market outlook: Accelerated case summary

The potential for accelerated hydropower deployment is in some ways limited to the current pipeline under construction and will depend on how fast civil works and permitting are completed at projects currently under development. Given the large pipeline, quantifying the accelerated case globally is somewhat difficult, but it is worth noting the dynamics that could affect the upside potential in different markets. China's deployment could be 9 GW to 17 GW higher by 2021 if several remaining large mega projects reach financial close and begin construction, potentially also causing a second peak in annual deployment over the medium term if finished before 2021.

Other market segments could accelerate, such as the refurbishment market in North America and the small hydropower segment in Europe and Eurasia, if support levels are raised. Small hydropower for rural electrification in sub-Saharan Africa and Asia also has the potential to be tapped if access to low-cost financing were more readily available. PSPs could be much higher under enhanced market conditions where ancillary grid services were adequately remunerated.

Onshore wind

Technology, manufacturing and cost developments

Over the last five years, the onshore wind industry has focused on maximising electricity generated per megawatt of capacity installed in order to lower the cost of energy and to unlock more sites with lower wind speeds. Overall, wind turbines have become bigger, with taller hub heights and larger rotor diameters with a greater swept area. Furthermore, these machines are now available with a wide range of rated generation capacity, allowing the industry to expand its product offerings to address site-specific conditions for a variety of wind resources. High-hub and large-swept-area machines originally developed for low- and medium-wind-speed sites can now be installed in relatively high-wind-speed sites provided that the level of turbulence remains acceptable.

Turbine demand trends vary geographically depending on local market dynamics, wind sites and the design of the incentive scheme. For example, Chinese wind turbine manufacturers, which supply the significant majority of local demand, mostly produce machines with 1 MW to 2 MW rated capacity and rotor diameters of 80 metres (m) to 90 m for high- and medium-wind sites. China’s FITs for onshore wind did not change over 2011-15 despite turbine cost reductions, so developers initially focused on developing high-wind-speed sites to maximise profits. However, this trend has already started to change as the FIT was reduced substantially for high-wind-speed sites but still remains attractive for lower-wind-speed sites closer to demand centres where the curtailment levels are low.

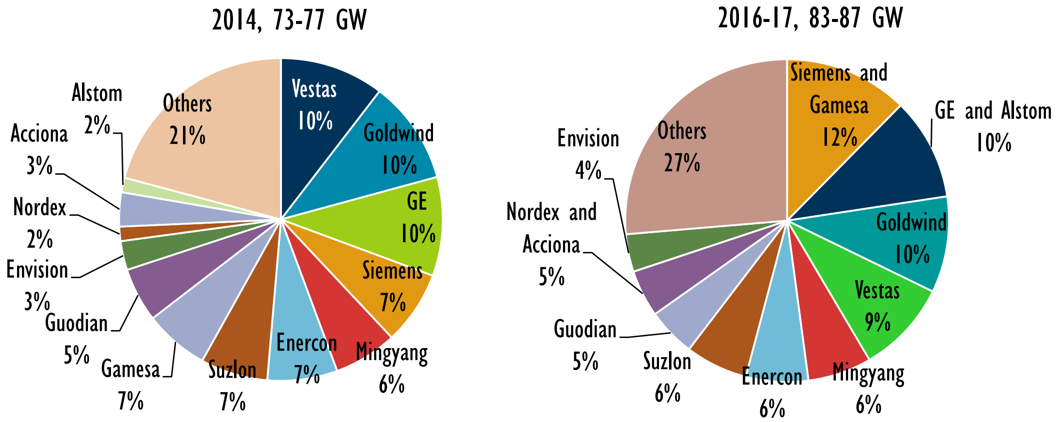
In India, developers have largely focused on realising tax benefits under the accelerated depreciation scheme, which is based on investment costs rather than output. Thus, local manufacturers have focused on producing low-cost turbines with 1.5 MW to 2 MW rated capacity and 85 m to 90 m rotor diameters. In general, European companies manufacture 2 MW to 4 MW turbines with larger swept areas. With the decreasing availability of high-wind-speed sites and reduced incentives, developers in Europe aim at maximising generation to get the most out of their benefits from existing incentives, which are mostly generation-based. The US market is also dominated by turbines with larger rotor diameters, although average nameplate capacity for new plants installed in 2014 remained below 2 MW. In the United States, the majority of new onshore wind installations are located in high-wind sites (the Interior Region). In some of these sites, some developers installed turbines with larger rotors (depending on turbulence levels) that were originally designed for medium-wind-speed sites in order to achieve higher capacity factors of 40-45%.

Global turbine manufacturing capacity ranged 73 GW to 77 GW in 2014, with the top ten manufacturers representing over 70% of the overall supply (Figure 2.10). In 2015, manufacturing capacity increased by an estimated 10 GW, with the majority of expansion taking place in China as a result of increasing local demand. Globally, a Chinese company (Goldwind) became the largest turbine manufacturer after this expansion in 2015, followed by the Danish company Vestas and American GE. However, this ranking is set to change in 2016-17 with several wind company mergers. With the acquisition of Alstom in November 2015, GE became the largest manufacturer globally. In

June 2016, Siemens and Gamesa signed binding agreements to merge Siemens' wind business with Gamesa. With the completion of this merger, the new company is expected to overtake GE's lead position. In addition, Nordex and Acciona completed their merger in April 2016.

Despite growing global and local demand, China's turbine market remains oversupplied with limited international expansion. The turbine market in China is dominated by three to five large companies, but there are also more than 20 small wind manufacturers. Further consolidation of the market is still expected, especially after the new quality standards introduced by the National Energy Administration (NEA) in late 2015.

Figure 2.10 Global wind turbine manufacturing capacity by company



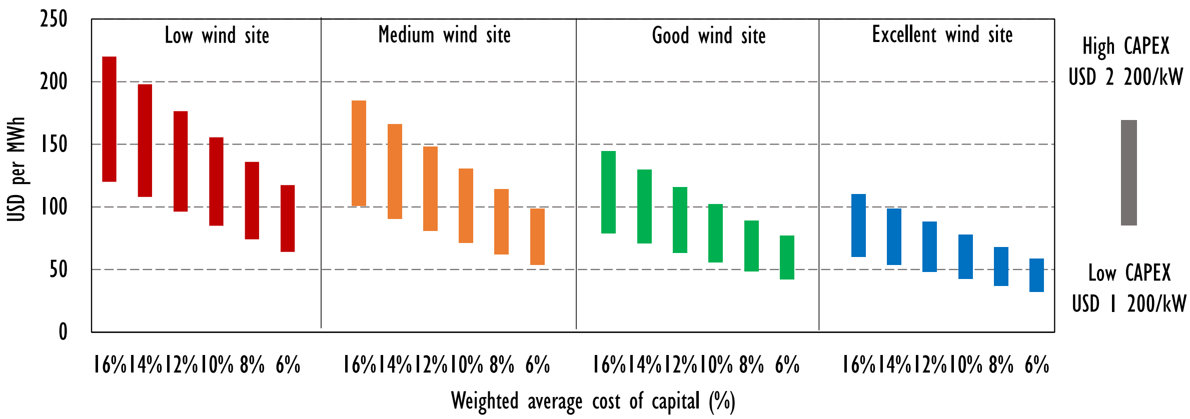
Source: Analysis based on BNEF (2016d), *Wind Manufacturing Plants Database.*

In general, wind turbine prices were stable over the last year and were estimated at USD 950/kW to USD 1 200/kW for high-wind-speed turbines and USD 1 150/kW to USD 1 250/kW for low- to medium-wind-speed turbines. Prices higher than these ranges (up to USD 1 500/kW) can also be observed for specific turbines designed for extreme weather conditions. However, some regional nuances remain. Overall, the pricing depends on complex local and global market dynamics that include competition for tenders, the design of financial support levels, project size and additional services (i.e. O&M) included in the final purchase contract.

- In China, prices for domestic turbines have increased slightly over the last couple of years due to growing local demand, with foreign manufacturers starting to offer lower prices to compete with local manufacturers.
- In Brazil, turbine prices have slightly increased due to strict local content requirements (LCRs) and the depreciation of the Brazilian real (BRL) against the US dollar which resulted in more expensive imported parts. Over the last year, LCRs have disqualified certain manufacturers' eligibility from the Brazilian Development Bank's (BNDES's) low-cost financing, impacting the demand-and-supply balance. In the rest of Latin America, turbine prices have been decreasing, with rising competitive pressure to supply new markets such as Mexico, Peru, Uruguay and Argentina.
- In the United States, the onshore wind market is highly dominated by large-scale projects (100 MW to 200 MW) in the interior region, where economies of scale have contributed to competitive pricing among many turbine manufacturers.

Turbine costs usually represent 65-80% of overall capital expenditure of an onshore wind project, depending on its size and location. Balance-of-system (BOS) costs can also vary significantly by country, depending on other expenditures associated with grid connection, construction and pre-development. While total system costs remain an important variable, weighted average cost of capital (WACC, or the cost of financing) and capacity factors are key in understanding the high variation of generation costs across countries (Figure 2.11). For the same investment costs and capacity factors, a two-percentage-point increase in WACC results in 11-15% higher generation costs.

Figure 2.11 Onshore wind generation cost variables and LCOE ranges



Notes: CAPEX = capital expenditure. Capacity factor assumptions: low wind site=21%, medium wind site=25%, good wind site=32, excellent wind site 42%.

The lowest onshore wind generation costs are observed in countries where excellent wind resources and a low cost of financing are available together. Thus, the lowest LCOEs are estimated in several large sites in Brazil and the United States, where capacity factors can be over 45% in some locations and developers are able to obtain relatively low interest rates.

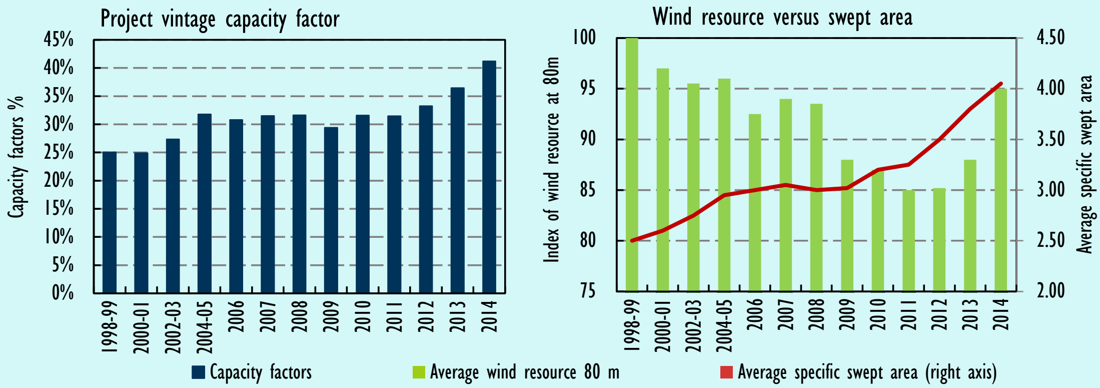
Box 2.1 Understanding wind energy capacity factor improvements, focus on the United States

Assessing the evolution of capacity factors of a large fleet of wind turbines with a great diversity of ages and technology types remains challenging. First, capacity factor calculations should be somehow normalised for yearly wind resource variations. Second, it is important to consider the exact commissioning date of newly added capacity, as some plants might be commissioned in the beginning of the year and others at the end. This plant-level information is usually not available in many countries, so capacity factor calculations should include assumptions on the commissioning date of the new capacity. If this assumption is consistent throughout the time series, it should reflect an accurate trend. Third, curtailment could be “offset” to isolate technology trends, or included to assess actual service to the system. The understanding of historically observed capacity and generation data points also remains challenging as these data might not fully reflect the decommissioning of some turbines.

A safer indication is given by the comparison of capacity factors of turbines of various vintages during one single year – and the performance of wind power in the United States, shown in Figure 2.12 above, delivers interesting lessons. Wind turbines erected before 2002 show capacity factors of 25%. Then the capacity factor increases; however, it plateaus around 30% over 2004-11. Then it increases again, reaching 36.5% in 2013 and 41% for projects commissioned in 2014.

Box 2.1 Understanding wind energy capacity factor improvements, focus on the United States (continued)

Figure 2.12 US onshore wind capacity factor, wind resource and turbine swept area by year



Sources: Berkeley Lab, quoted by Wiser and Bolinger (2016), *2015 Wind Technologies Market Report*, US DOE.

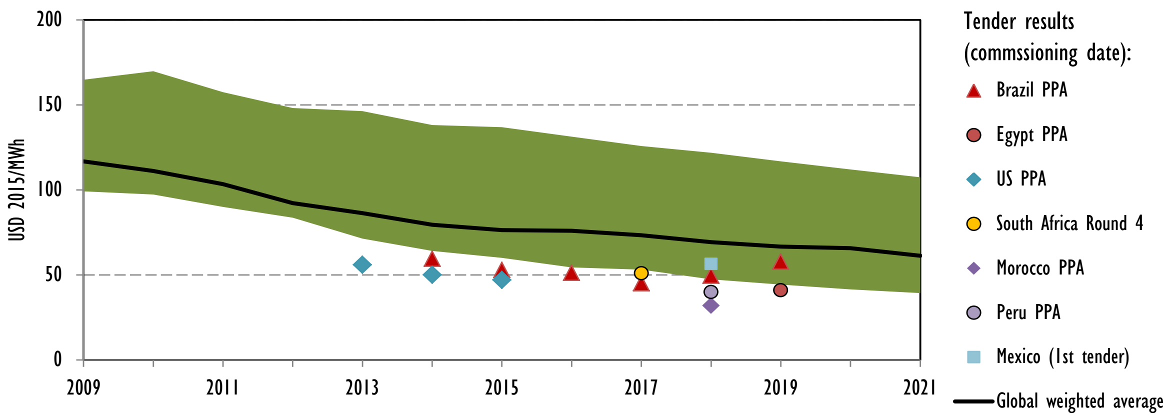
This evolution is best explained as a result of the variations of the specific swept area of the new build, together with the evolution of the average wind resource quality of the sites where they were installed, as reported in Figure 2.12. It shows how the emergence of machines with higher swept areas first led developers to investigate new, lower-wind-speed sites. Since 2011, machines were installed in higher-wind-speed areas while the average specific swept area continued to increase.

Without the Production Tax Credit (PTC), average PPAs for a selected number of projects in the United States ranged from USD 42/MWh to USD 51/MWh over 2015-16 (DOE, 2016). In Brazil, wind projects that signed PPAs as low as USD 50/MWh came on line in 2015. While the lowest onshore wind CAPEXs are observed in China and India (USD 1 100/kW to USD 1 300/kW), LCOEs in these countries are usually higher than in Brazil and closer to those estimated in the United States. In China, despite the availability of low-cost financing from state-owned banks, projects have in general low capacity factors in the range of 17-24% due to high curtailment rates. In 2015, LCOEs for typical projects were between USD 65/MWh and USD 80/MWh. In India, current generation costs are higher, USD 75/MWh to USD 95/MWh, as a result of low capacity factors and high interest rates.

Germany has one of the lowest WACCs (4-6%) globally but on average, investment costs are relatively high. The majority of projects commissioned over 2013-15 installed relatively more expensive turbines designed for medium- and low-wind-sites. In addition, costs associated with land, construction and permitting remain overall high in many European countries. Accordingly, current LCOEs were USD 70/MWh to USD 110/MWh, depending on the wind site. The highest LCOEs are observed in Japan, ranging from USD 130/MWh to USD 170/MWh for typical projects despite low interest rates. This is mainly due to high investment costs ranging from USD 1 900/kW to USD 2 200/kW, the highest globally. Difficult topography, expensive land, costly turbines adapted to special meteorological conditions, high construction and transportation costs, and lack of grid availability, combined with an expensive and long pre-development process, are the main factors behind these high investment costs.

Overall, typical LCOEs ranged from USD 60/MWh to about USD 140/MWh in 2015. In the majority of countries having some deployment experience, LCOEs for onshore wind projects are between USD 65/MWh and USD 85/MWh, with global weighted average generation costs estimated around USD 75/MWh. Over the medium term, weighted average LCOEs are seen decreasing by another 15%, reaching USD 64/MWh. However, recently signed PPAs in Mexico, Peru, Morocco and Egypt for projects expected to come on line 2017-20 indicate possible lower generation costs (Figure 2.13). These projects are seen having either exceptional capacity factors (40-50%) and/or favourable financing conditions. This trend is expected to continue over the medium term as more countries are expected to open renewable energy tenders where wind resources are still untapped, such as in Argentina, Egypt and Morocco.

Figure 2.13 Historical and forecast LCOEs for typical onshore systems, beginning year



Market status and outlook: Main case summary

In 2015, onshore wind generation increased by an estimated 120 TWh to reach over 810 TWh (17% y-o-y). Global cumulative grid-connected capacity stood at 405 GW, 18% higher than in 2014. In 2015, new grid-integrated onshore wind installations were over 62 GW. China represented more than 50% of this new capacity, with 32 GW coming on line, as developers rushed to connect their projects to take advantage of relatively higher tariffs before planned FIT reduction. The European Union added 10 GW of new capacity led by Germany (3.7 GW), Poland (1.3 GW), France (1.1 GW) and the United Kingdom (0.7 GW). Outside of the European Union, annual installations were strong in Turkey (1 GW). In Latin America, Brazil connected 2.7 GW while smaller additions came from Chile, Uruguay and Peru. In India, annual capacity additions reached 2.6 GW in 2015, 14% higher versus 2014.

Over the medium term, global cumulative grid-connected onshore wind capacity is expected to grow from 406 GW in 2015 to 703 GW in 2021 (Table 2.3). Compared with *MTRMR 2015*, the cumulative capacity is 50 GW higher in 2020 mainly due to the long-term extension of the PTC in the United States, the announcement of a new wind capacity target in China and successful policy implementation in Mexico. Onshore wind generation is expected to almost double over the medium term and reach around 1 545 TWh in 2021. Its share in global electricity generation is forecast to increase from 3% in 2014 to over 5% in 2021. Overall, onshore wind remains the second-largest renewable generation source after hydropower.

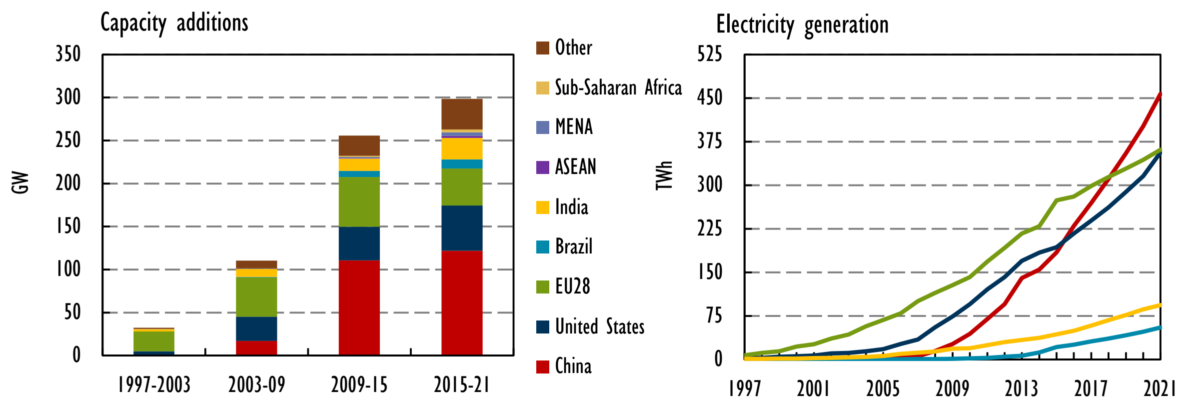
Table 2.3 Onshore wind capacity and forecast by region (GW)

	2014	2015	2016	2017	2018	2019	2020	2021
North America	77.1	87.9	98.4	107.2	116.7	127.9	142.5	153.4
Latin America	7.5	11.1	14.5	16.2	18.9	21.2	23.9	26.9
Europe	125.3	136.6	147.0	156.0	163.0	171.2	179.4	187.6
Asia and Pacific	32.9	36.5	41.8	48.8	55.2	61.1	67.0	71.9
China	96.2	128.3	148.3	167.3	186.8	206.8	227.8	250.3
Eurasia	0.6	0.7	0.8	0.9	1.1	1.4	1.6	2.1
MENA	1.7	2.0	2.4	2.9	3.6	4.3	5.1	6.0
Sub-Saharan Africa	0.9	1.5	1.9	2.5	3.0	3.7	4.4	5.0
World	**342.1**	**404.7**	**455.1**	**501.7**	**548.3**	**597.7**	**651.7**	**703.2**

Sources: Historical data based on IEA (2016d), *Renewables Information 2016*, www.iea.org/statistics/; GWEC (2016), *Global Wind Statistics 2015*; WindEurope (2016b), *Wind in Power 2015 European Statistics*; IRENA (2016b), *Renewable Capacity Statistics 2016*.

By 2021, **China**'s grid-integrated onshore wind capacity is expected to be over 250 GW, representing over 35% of cumulative onshore wind installations globally. The country is the main driver of the global onshore wind outlook, with 122 GW of new additions expected to be commissioned over 2015-21. This capacity growth represents more than 40% of global onshore wind deployment over the medium term. China's onshore wind generation is set to more than double, reaching 460 TWh as integration challenges are seen improving over the forecast period. This report expects improvements in the capacity factor of new plants. China's electricity generation from onshore wind is anticipated to surpass the United States by the end of 2016 and the European Union by 2018 (Figure 2.14).

Figure 2.14 Onshore wind cumulative net capacity additions and generation (1997-2021)



Note: ASEAN = Association of Southeast Asian Nations.

Sources: Historical capacity data sources same as Table 2.3. Historical generation data based on IEA (2016a), *World Energy Statistics and Balances 2016* (database), www.iea.org/statistics/.

The US onshore wind market should follow China, with over 52 GW expected to be deployed over the medium term, reaching 126 GW in 2021. With the long-term extension of the PTC, US onshore wind cumulative additions over the five-year period are seen 80% higher versus *MTRMR 2015.* The average capacity factor of the US onshore wind fleet was over 30% in 2015, high compared with 19% in China. However, this report expects capacity factors of new plants to be higher than aforementioned values for both countries. In the United States, the availability of good sites in the

Interior Region combined with turbine technology improvements is expected to result in higher full-load hours compared with cumulative fleet average. In China, overall capacity factors for both the existing fleet and new additions are seen slowly increasing over the forecast period, reflecting expected improvements in curtailment rate and grid expansion.

The European Union remains the third-largest market with new additions reaching 43 GW over 2015-21. Germany is expected to lead this growth (+16.7 GW), followed by France (+7.3 GW), the United Kingdom (+3.5 GW) and Poland (+0.9 GW). Overall policy uncertainty concerning 2030 targets in the European Union has influenced the outlook, along with macroeconomic challenges affecting project financing. Onshore wind expansion has stalled in some countries in Southern and Eastern Europe due to retroactive policies and/or drastic cuts in incentive schemes. In addition, grid integration and social acceptance issues are expected to slow growth in several countries in Europe including France and United Kingdom. Despite these challenges, the European Union is seen keeping its second position after China in terms of cumulative installed capacity (174 GW) in 2021.

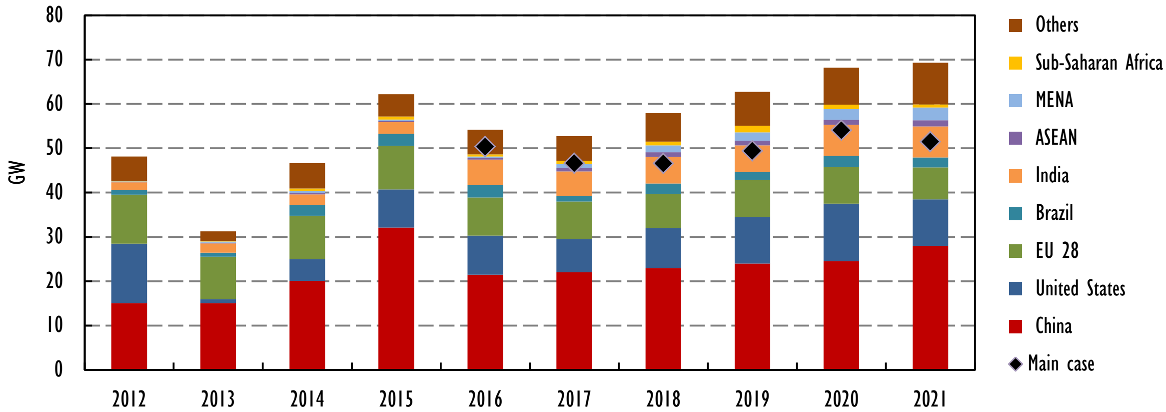
India's onshore wind capacity is forecast to grow by 25 GW over the medium term. However, the forecast is revised down versus *MTRMR 2015* mainly due to changing incentive schemes and challenges concerning grid integration and land use. In Brazil, onshore wind is expected to grow despite current macroeconomic challenges and increasing financing rates. The forecast is revised down but remains robust, with 11 GW of new capacity expected to come on line over the medium term.

In the MENA region, renewable energy auctions, PPPs and procurement programmes, usually combined with long-term PPAs, should drive deployment. The majority of deployment is anticipated to come from **Egypt** (+1.5 GW), **Morocco** (+0.8 GW) and **Iran** (+0.5 GW). Overall, sub-Saharan Africa's onshore wind potential remains mostly untapped over the forecast period. With well-designed policy frameworks, onshore wind projects can attract both domestic and development financing. However, grid connection and integration pose significant challenges to deployment. **South Africa** leads the growth in the region with 2 GW of new capacity expected to come on line, followed by Kenya (+0.5 GW) and Ethiopia. In ASEAN, excellent wind resources in some countries and recent government initiatives to help exploit them will pave the way for the modest deployment of just over 2.5 GW of onshore wind in the medium term, led by **Thailand and the Philippines**.

Market outlook: Accelerated case summary

Under the accelerated case conditions described in the regional sections of Chapter 1, global cumulative onshore wind capacity could reach 730 GW to 772 GW in 2021. This would imply an additional 30 GW to 70 GW of onshore capacity growth globally with the range reflecting uncertainty of the enhancements occurring in concert both within and between markets. In 2021, under accelerated deployment, annual onshore wind installations could reach 70 GW (Figure 2.15). China alone represents 30% of this accelerated growth, followed by India (17%), the European Union (16%), MENA (10%) and the United States (10%). Achieving enhanced deployment would require alleviating some of the challenges highlighted above and repeated through this report. These include, but are not limited to, the rapid clarification of policy uncertainties in some markets; greater measures to ensure the grid, system and market integration of variable renewables; improved reductions in non-economic barriers; and faster-than-expected decreases in onshore wind technology and generation costs.

Figure 2.15 Onshore wind annual additions by region under accelerated and main cases



Solar PV

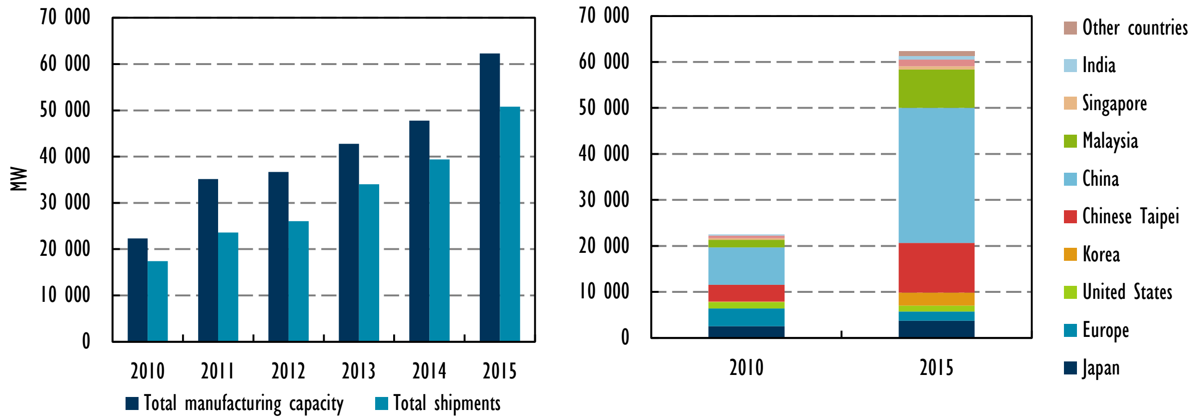
Technology, manufacturing development

Falling system prices and increasing annual global deployment in newer markets continue to mark the trend for solar PV development. Module price reductions have flattened while reductions in BOS costs are stimulating lower investment costs, with the lowest industry-reported system prices for some large-scale utility projects below USD 1 000/kW. With attractive financing and good resources, low contracted remuneration prices were achieved in an increasing number of markets, supporting deployment with lower levels of financial support.

Module prices declined by around 70% over 2010-15 globally, while remaining largely stable over the last year in major markets including China, Japan and Germany. In early 2016, global average module prices ranged from USD 0.55 per watt (W) to USD 0.75/W. Country differentials remain as local demand-and-supply dynamics, trade measures and support schemes continue to play a role in local module and panel pricing. China remains at the lower end of the module price range despite increasing domestic demand, which provided some price stabilisation in the country. Japan is at the higher end of the module pricing spectrum with local manufacturing focusing predominantly on high-quality products. High FIT levels are likely to have played a role in relatively elevated solar panel prices. However, with the increasing imports of lower-cost modules, primarily from China, to meet growing demand, average module prices in Japan are expected to decrease over the medium term.

In 2015, global manufacturing capacity increased by 30% and reached around 62 GW (Figure2.16) while shipments (or sales) were close to 51 GW (SPV Market Research, 2016). Shipment utilisation of capacity was around 82%, up from 70% in 2011-12. More than half of global solar module/cell manufacturing capacity is located in China. However, Chinese companies continue to invest in new manufacturing capacities elsewhere in Asia. In 2015, Chinese Taipei and Malaysia together represented 30% of global manufacturing capacity and emerged as important manufacturing hubs for some Chinese companies to avoid import tariffs. With the European Union and the United States expanding the geographical coverage of their trade duties against Chinese manufacturers over the last year, other Asian economies including Thailand, Korea, Viet Nam and the Philippines are expected to play a larger role in cell manufacturing going forward.

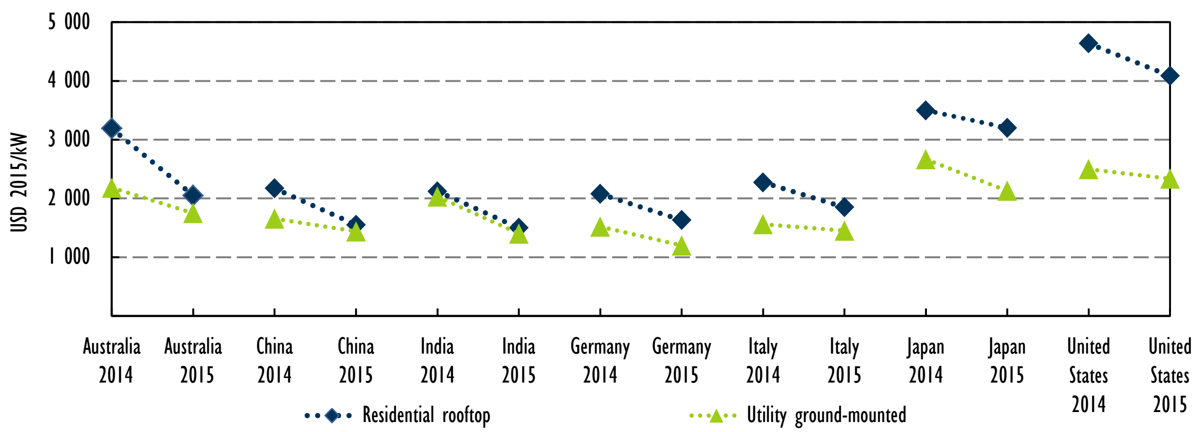
Figure 2.16 Solar PV total manufacturing capacity and shipments (left) and manufacturing capacity by country/region (2010-15)



Sources: SPV Market Research (2016a), "The solar flare – Issue 1"; SPV Market Research (2016b), "The solar flare – Issue 2".

In 2015, the weighted average solar PV system prices for both utility- and residential-scale projects continued to decrease. It is important to note that average prices are calculated based on a representative selection of commissioned projects, not on the basis of final investment decision. For utility-scale installations, the time between final investment decision, or financial closure, and actual commissioning may vary significantly from one year up to four years for some large-scale projects. This time also explains price differences with recently announced PPAs and auction results. In 2015, average system prices for commissioned projects ranged from USD 1 200/kW to USD 2 400/kW with the lowest prices observed in Germany, China and India (Figure 2.17). Higher prices were observed in Japan due to generous FIT prices, appropriate land availability constraints and grid connection and permitting challenges. In the United States, relatively high average system prices in 2014-15 for utility-scale projects stemmed, in part, from the commissioning of relatively high-cost projects signed with supply contracts and PPAs over 2011-13. Residential prices are usually higher than those of utility-scale projects, ranging from USD 1 250/kW to USD 4 000/kW. Commercial rooftop prices are generally closer to utility-scale prices due to their relatively larger size. Significant differences remain among markets and segments depending on business models, the regulatory environment and the nature of financial incentives provided.

Figure 2.17 Typical solar PV average system prices for commissioned projects (2014-15)



Source: Analysis based on IRENA (2016a), *Costing Alliance*, dataset provided to the IEA.

Looking ahead, solar PV investment costs are likely to decline due to a combination of continued global learning in module production and local improvements in BOS costs. Average crystalline module prices are expected to range from USD 0.35/W to USD 0.55/W, in real terms, by 2021 given this report's expected solar PV deployment outlook. However, solar PV modules constitute only a limited portion of overall system costs while BOS costs can represent up to 70% in some markets. Therefore, the cost reduction potential for BOS remains high while its achievement can be dependent upon local market dynamics.

Non-hardware, "soft" costs of PV systems remain diverse depending on market maturity, financing schemes and the policy environment and are expected to fall drastically with market maturation, increased competition and the mitigation of excessive support levels. Reductions of soft costs are expected to represent over half of the total reductions in global capacity-weighted average solar PV system costs in the next five years (IRENA, 2016c).

Where system costs are already the lowest, future cost reductions will continue to be driven primarily by technology improvements. More efficient processes for manufacturing wafers and cells, such as diamond wire sawing, will progressively replace the most widespread current technologies, such as slurry-based sawing, improving silicon efficiency, reducing losses and thus manufacturing costs. Similarly, the amount of silver per cell could be reduced. Meanwhile, conversion efficiencies continue to increase in each family of crystalline cells as well as thin films. Furthermore, the most efficient families increase their market shares, pushing the average efficiency of the existing fleet up slowly. The industry expects an increase of the share of monocrystalline silicon (mono-Si) to roughly half the total module market in ten years, of which a majority would be of the more efficient n-type, including heterojunction and back-contact technologies (IRTPV, 2016). This increase in cell efficiency means less surface per watt and remains a primary factor for cost decreases in the hardware of systems, from module manufacturing to cabling, racking and mounting, and other hardware-related BOS costs.

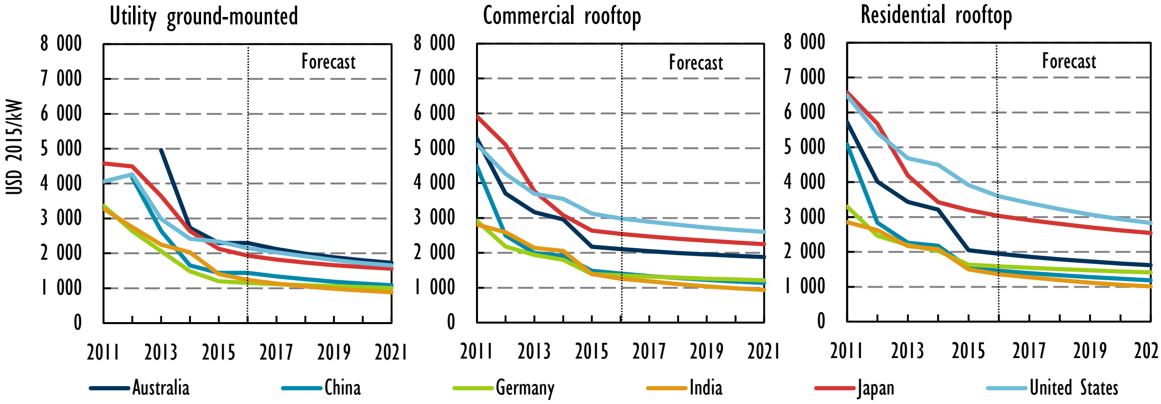
In addition to reductions in investment costs, improvements in capacity factors are also observed with new technology deployment. The costs of one-axis trackers fell considerably while their reliability increased. As a result, the share of sun tracking systems in utility-scale projects has increased, notably in California. The majority of these plants are equipped with crystalline silicon technology, but some developers also started to install a growing share of thin-film panels with trackers over the last two years, at an extra cost of USD 0.30 per watt alternating current (W_{AC}) (Bolinger and Seel, 2015). This trend was likely encouraged by time-of-delivery payments, as tracking the sun on one axis not only increases the annual average electricity output by 12% to 25% but creates a high value for the system in hours of peak demand, notably in late afternoons.

For utility-scale projects, increasing price competition stimulated by recent tender and auction schemes is expected to reduce supply chain margins for BOS costs. As developers become global players, their multi-market development experience may contribute to lowering cost inefficiencies in more countries. This report expects the majority of cost reductions over the medium term to come from BOS. Accordingly, typical utility-scale solar PV system costs could, in real terms, reach as low as USD 850/kW in India and China in 2021 (Figure 2.18).

For distributed-scale projects, increasing competition among developers, access to low-cost financing, and a better regulatory environment that reduces permitting and licensing costs are expected to contribute to system cost reductions. Accordingly, commercial rooftop systems can fall below USD 950/kW in India and USD 1 200/kW in Germany, while residential deployment below

USD 1 500/kW is expected to occur in China, India, Australia and Germany. Average costs are likely to remain relatively higher than these levels in Japan and the United States.

Figure 2.18 Historical and forecast typical solar PV investment costs, average for new capacity

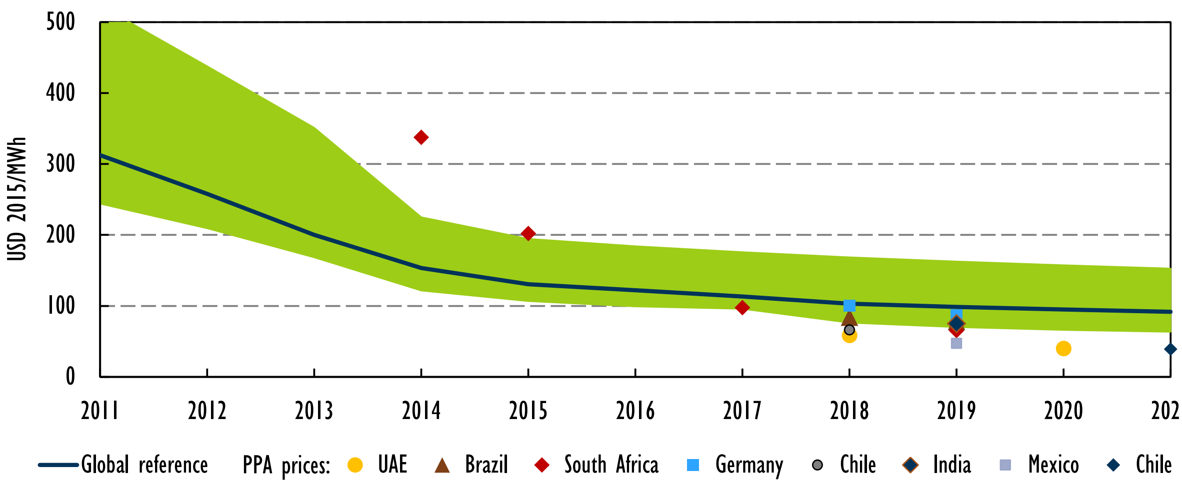


Notes: Investment costs are overnight costs and include value-added tax or sales tax where relevant; costs are indicative and may not represent all transactions. National currencies converted to US dollars at average 2015 exchange rates. Historical data points omitted for Australia, where market was not well established.

Sources: Analysis based on IRENA (2016a), *Costing Alliance*, dataset provided to the IEA; IEA-PVPS (2016), *PV Cost Data for IEA,* dataset provided to IEA.

Globally, LCOEs without subsidies for typical utility-scale projects fully commissioned in 2015 are estimated from above USD 100/MWh to over USD 195/MWh (Figure 2.19). Within this range, China and India are at the low end, while Japan and the United States are at the high end. In 2016, the estimated global reference suggests that weighted average deployment can take place around USD 120/MWh, 60% lower than in 2011. Over the medium term, continued system cost reductions, driven primarily by BOS costs and capacity expansion into newer markets with better resources, could reduce global reference LCOE for weighted average deployment to around USD 90/MWh in 2021. LCOEs for typical utility-scale projects could range from USD 60/MWh to USD 150/MWh.

Figure 2.19 Historical and forecast LCOE range for typical utility-scale solar PV plants



Notes: Costs are indicative, and ranges reflect differences in resources and local conditions. Global reference is the estimated global weighted average based on *MTRMR* generation forecast. Tendered prices are nominal values based on auction announcements and correspond to dates when commissioning of auctioned capacity is expected. Delivered project costs may ultimately be different from those reported at the time of the auction, the signature of the PPA or the commissioning date indicated in the figure. For more data assumptions behind the calculations, see table 5.2 in "Analytical framework" chapter.

However, recent PPA announcements from newer markets indicate that potentially much lower costs could be achieved for projects commissioned in coming years. In Mexico, weighted average bid prices for winning projects were around USD 45/MWh, with the lowest price at USD 35/MWh (but with a time-of-delivery bonus worth USD 5/MWh, on average). In Peru, solar PV developers signed 30-year PPAs at USD 48/MWh in 2015. In India, recent state-level auctions awarded prices for PPAs around USD 65/MWh. Solar PV was awarded as low as USD 60/MWh in Zambia, which benefits from advisory services and partial risk guarantees from the World Bank's Scaling Solar programme. In the latest auction in the United Arab Emirates, the lowest winning bid was around USD 30/MWh for an 800 MW plant awarded in July 2016. In Chile, a 120 MW solar PV plant won the August 2016 auction with just over USD 29/MWh, which is expected to be commissioned in 2021.

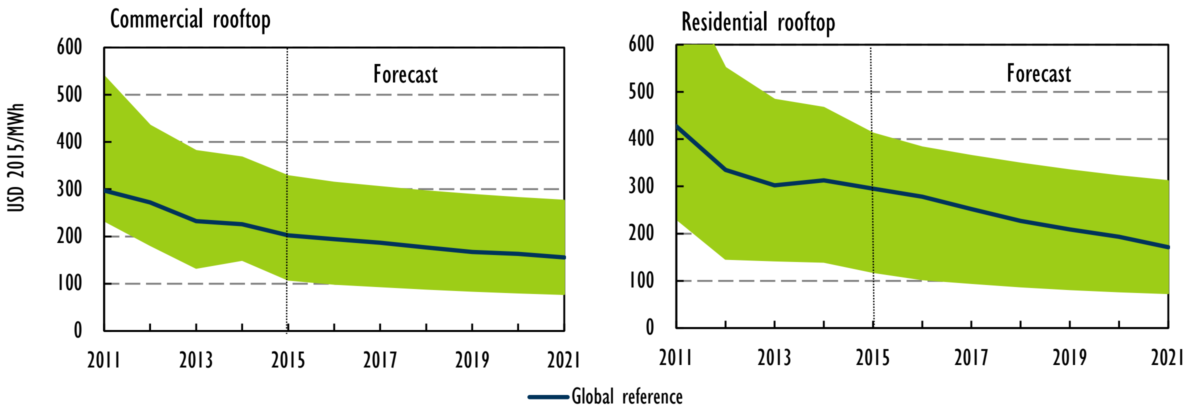
It is important to note that these tender results and PPA announcements are not directly comparable with LCOE calculations, as projects may have particular assumptions on capacity factors and WACC depending on the particular site and developers' financing resources. In addition, specific auction designs and contract types may have an impact on overall generation costs. Moreover, delivered project costs can ultimately be different from those reported at the time of the auction or the signature of the PPA. Still, these numerous data points signal a strong acceleration in the reduction of generation costs where deployment is starting to ramp up quickly. The significant majority of utility-scale solar PV deployment over the medium term in Latin America, the Middle East, Africa and parts of Asia (particularly in India) should be driven by competitive auctions with long-term PPAs.

Overall, the generation cost outlook suggests a growing economic attractiveness of solar PV, with fewer incentives, versus other bulk power sources. Still, a fuller competitiveness assessment versus other power sources would need to take into account the system value of solar PV, where it reaches a high level of penetration in power generation, and where and when its electricity is produced. In general, the system value of solar PV will be greater in sunny countries with daytime peak demand. However, the value can quickly decrease when solar PV reduces this peak, displaces mid-merit and base-load generation, and decreases wholesale prices through the merit order effect. These self-cannibalisation effects can be partly mitigated at increased penetrations with options such as tracking the sun or different orientations of modules, which could face both east and west, or simply west, instead of the equator, offering higher capacity factors and inverter load (or direct current/alternating current [DC/AC]) ratios.

Generation costs for distributed solar PV are also improving. For new commercial-scale projects, the global reference, in real terms, is moving from USD 205/MWh in 2015 to around USD 155/MWh in 2021 (Figure 2.20). Costs at or below this average are seen in markets such as Italy and Germany. In China and Australia, generation costs for typical systems are expected below USD 100/MWh in 2021. For new residential-scale projects, the global average reference for installed projects is moving from USD 300/MWh in 2015 to USD 180/MWh in 2021, with much lower values expected in China, Australia, Germany and Italy, where financing costs are low. In these countries, LCOEs are expected to range from USD 110/MWh to USD 140/MWh in 2021.

Falling costs are supporting the development linked to the concept of grid or "socket" parity – when the LCOE of distributed solar PV systems becomes lower than the variable portion of retail electricity prices that system owners would otherwise pay. Reaching socket parity in itself may or may not be sufficient to trigger deployment, which will depend on the match between solar PV generation and power demand for self-consumption and the remuneration available for excess electricity injected into the grid.

Figure 2.20 Historical and forecast LCOEs for typical commercial- and residential-scale solar PV plants



Note: Costs are indicative, and ranges reflect differences in resources and local conditions. Global reference is the estimated global weighted average based on *MTRMR* generation forecast. For more data assumptions behind the calculations, see table 5.2 in "Analytical framework" chapter.

In the case of net energy metering, still the prevalent scheme in most of the United States, the surplus electricity injected implicitly receives the retail tariff, although some states (i.e. Nevada) already switched remuneration level from the retail price to wholesale price. In other countries, the level of remuneration goes down to that of wholesale electricity markets, sometimes topped up by components representing avoided increases in generation capacity, avoided network strengthening costs or various externalities of the most likely alternatives. Overall, the match between solar PV generation and power demand will likely have a stronger influence on the structure of cost-reflective schemes.

Based on arguments related to economic efficiency and fairness among different categories of customers, retailers and utilities often advocate for tariff reforms that would reduce the volumetric component of retail electricity prices. Cost recovery would then rest on an increase of a fixed or power-related component (or both). A slightly more sophisticated method would be tariff-setting based on the individual power demand at times of consumption peaks and other time-based energy pricing. While in some cases such tariff reforms drove sudden and significant changes in market dynamics, in others they were or will be progressive enough to prevent massive disruptions in distributed solar PV deployment (see box 2.3, "A Rooftop solar PV in Australia").

Box 2.2 Battery storage and distributed solar PV

Inexpensive and economical battery storage is often announced as "just around the corner". However, prices continue to start at USD 1 100 per kilowatt-hour (kWh) for small systems and USD 550/kWh for large systems (e.g. Tesla Powerwall and Powerpack in the Australian market). Such high prices make the profitability of battery systems challenging for homeowners who want to increase their self-consumption from rooftop solar PV, as payback time may exceed technical lifetime. The cost trend can change over the next few years if the learning curve for battery storage begins to resemble that of solar PV modules. For example, the manufacturing capacity for battery storage can ramp up quickly with the rapid dissemination of electric vehicles. Meanwhile, demand-side management options, which allow for piloting the consumption of a variety of appliances (e.g. directing excess power to electric water heaters) remain a more economical option to increase self-consumption today.

Box 2.2 Battery storage and distributed solar PV

Some utilities have recently introduced new products and contracts for distributed solar PV systems, including battery storage, to meet the increasing demand from customers despite the high costs. However, maximising self-consumption without enabling customers to sell their surplus (aka "self-use"; see IEA, 2014) may lead to smaller solar PV systems compared with available building space, and may disincentivise efficiency improvements. Instead of increasing PV capacities on the condition of selling surplus to the grid, an important priority in the residential sector of temperate climates, maximising self-production (aka "self-sufficiency") would create the opposite effect.

Where selling surplus energy back to the grid is not prohibited, using battery storage to increase self-consumption when it becomes profitable is unlikely to help reduce peak injection in the middle of the day as batteries can become overfilled. Time-based tariffs may be required to induce a different use of battery storage, which has the ability to reduce peak injection by over 50%. However, an even cheaper option remains to downsize the AC capacity of the inverter to 70% of the DC capacity of the distributed PV systems, therefore increasing the DC-to-AC capacity ratio or "inverter load ratio" to the detriment of only a few percentage points of annual energy. This would significantly increase the effective capacity factor relative to the AC capacity.

Market status

In 2015, solar PV generation increased by an estimated 44 TWh to reach over 233 TWh (23% y-o-y). Global solar PV cumulative capacity grew by an estimated 49 GW, 25% higher than the annual installations in 2014. Globally, it is estimated that over 60% of new additions came from utility-scale projects, followed by commercial (23%) and residential (15%) applications. Overall, two countries in Asia represented more than 50% of the annual market in 2015, with record level installations in China (15 GW) and Japan (11 GW). The United States continued to remain the third-largest solar PV market globally with a record 7.3 GW additions, followed by the United Kingdom (3.8 GW) and India (2 GW).

Table 2.4 Solar PV cumulative capacity forecast by region (GW)

	2014	2015	2016	2017	2018	2019	2020	2021
North America	20.8	28.8	38.5	46.4	56.3	67.9	79.9	90.7
Latin America	0.7	1.7	3.1	4.2	5.8	7.7	9.0	10.5
Europe	87.9	96.1	102.7	107.9	113.2	118.4	124.0	129.6
Asia and Pacific	35.5	51.6	68.3	84.9	97.2	109.3	123.1	136.9
China	28.1	43.2	70.2	87.2	104.2	122.2	140.2	160.2
Eurasia	0.5	0.6	1.0	1.2	1.4	1.8	2.0	2.2
MENA	0.8	1.4	1.8	3.0	4.0	5.6	7.6	9.5
Sub-Saharan Africa	1.3	1.3	2.2	3.1	4.0	5.0	6.1	7.3
World	**175.6**	**224.6**	**287.7**	**337.8**	**386.1**	**437.9**	**491.8**	**546.9**

Sources: Historical data based on IEA (2016d), *Renewables Information 2016* (database), www.iea.org/statistics/; IRENA (2016b), *Renewable Capacity Statistics 2016*; Masson, G. (2016), *2015 Snapshot of Global Photovoltaic Markets*.

In 2015, **China** connected over 15 GW of new solar PV capacity. More than 90% of new additions occurred in the utility-scale segment as legal and financing challenges remain for distributed projects, especially for commercial and industrial-scale applications. The majority of solar PV deployment is located in the northern provinces, where curtailment levels are high for all renewables. In 2015, the average curtailment for solar PV was around 10%, and initial data from the NEA show that it increased to 13% in the first quarter of 2016.

Japan led the Asia and Pacific region with record-level capacity additions, adding 11 GW, driven by a generous FIT. Commercial applications represented around half of new installations, followed by utility-scale (39%) and residential (9%) projects. Since the introduction of the FIT in 2012, distributed generation has led the solar PV market as utility-scale projects face challenges concerning grid connection and permitting. As of March 2016, the Ministry of Economy, Trade and Industry approved 53 GW of solar PV projects in total. However, a new regulation published in June 2016 requires these projects to submit their grid connection agreements with integrated electricity and power companies (EPCOs) by March 2017 in order to keep their FIT eligibility, which suggests that many could be cancelled. **India's** annual solar PV additions marked a record with 2 GW connected to the grid in 2015, primarily from utility-scale projects that were awarded under the federal government's Jawaharlal Nehru National Solar Mission and state-level auctions. In 2015, **Korea** installed 1 GW of new capacity for the second year in a row, driven primarily by renewable portfolio standard (RPS) obligations and Renewable Energy Certificates. In ASEAN, annual additions increased from 0.6 GW in 2014 to 0.9 GW in 2015, due to higher additions recorded in **Thailand** (0.7 GW) last year versus 2014 (0.5 GW) as some projects face grid connection and financing challenges. The solar PV market picked up in **the Philippines** under the government's FIT programme, with 130 MW coming on line in 2015.

In North America, **the United States** deployed 7.3 GW, with growing economic attractiveness and support from the ITC and state-level incentives for net metering. Utility-scale projects continued to dominate, representing close to 60% of annual additions, followed by residential and commercial installations. California led the new additions, representing about 45% of the annual market in 2015, followed by North Carolina (16%) and Nevada (6%); Massachusetts (4%) and New York (3%) followed with smaller additions. In **Canada**, annual solar PV additions were stable at 0.6 MW with Ontario leading the growth with its FIT and public procurement programme. **In Mexico**, the annual market was just above 100 MW.

In the European Union, solar PV additions increased by close to 8% to 7.6 GW in 2015 versus 2014. This increase is thanks to a record level of installations in the **United Kingdom** (3.7 GW) as developers rushed to finish their projects before the end of the utility-scale incentive scheme. New solar capacity also peaked in **Denmark,** with project owners rushing to complete projects to take advantage of subsidies. Aside from the United Kingdom and Denmark, annual installations dropped the second year in a row to 1.4 GW in **Germany** due to a continued decrease in incentive levels and the phase-out of the FIT for large systems. **In France**, new solar PV capacity was around 0.9 GW, roughly 10% lower compared with 2014 deployment.

In Latin America, annual solar PV additions almost doubled thanks to deployment in **Chile** (0.45 GW) and Honduras (0.39 GW), mostly from utility-scale projects. In MENA, around 95% of new additions came from only two countries: **Israel**[1] (0.22 GW) and **Algeria** (0.27 GW). In **South Africa**, annual additions dropped from 0.75 GW in 2014 to only 6 MW in 2015 due primarily to a lull in the project pipeline.

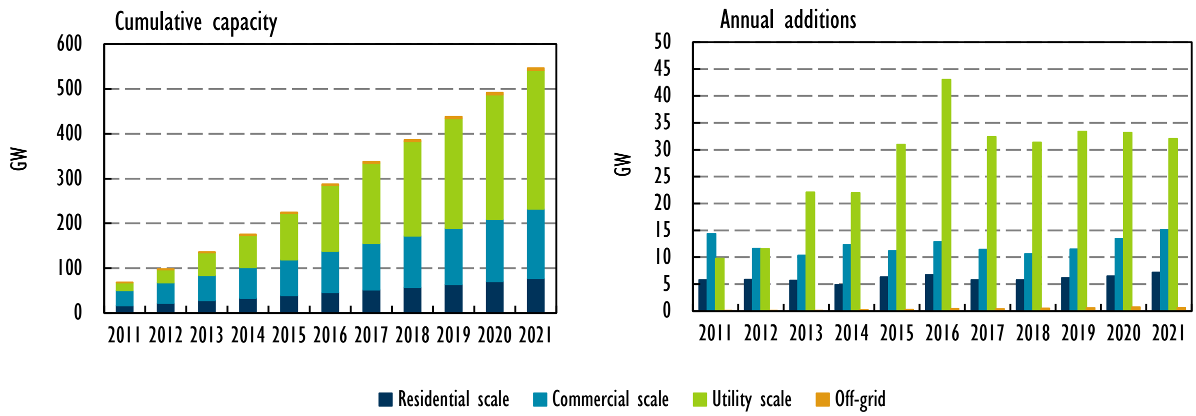
[1] The statistical data for Israel are supplied by and under the responsibility of the relevant Israeli authorities. The use of such data by the OECD is without prejudice to the status of the Golan Heights, East Jerusalem and Israeli settlements in the West Bank under the terms of international law.

Market outlook: Main case summary

Looking ahead, global solar PV cumulative capacity is expected to rise from 225 GW in 2015 to almost 547 GW in 2021 (+16% annually, on average). The forecast is revised up by almost 60 GW in 2020 compared with *MTRMR 2015*, reflecting more optimistic growth prospects across a number of markets including China, India, Mexico and the United States, and due to improving policy environments and cost reduction expectations. Solar PV generation is expected to grow by around 435 TWh over 2015-21. Its share in global electricity generation should increase from less than 1% in 2015 to close to 2.5% in 2021.

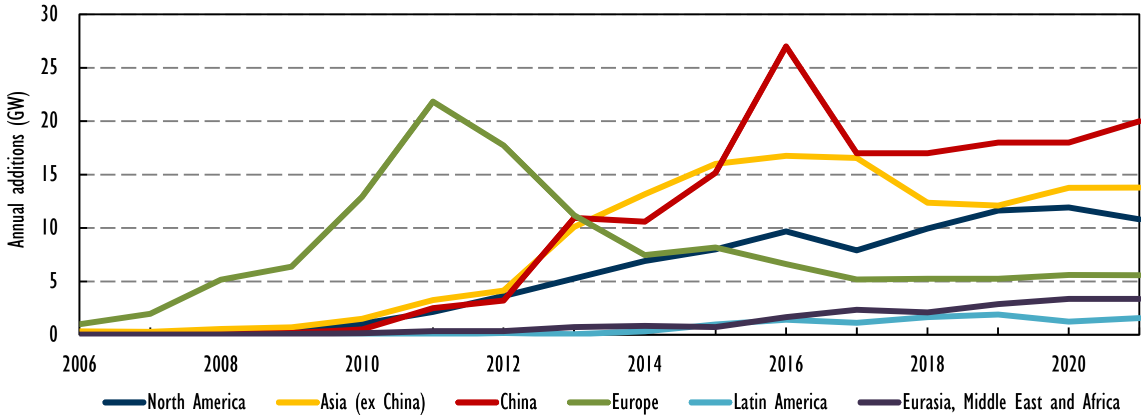
Over the medium term, utility-scale projects are expected to dominate the growth and account for over 60% of new additions. In China, the FIT should continue driving growth, while the US ITC is expected to maintain its important role in utility-scale deployment looking ahead. Aside from these two countries, policy-driven and government-administrated auctions should spur the majority of new additions, especially in Latin America, the Middle East and Africa. The commercial segment is projected to represent 25% of the new deployment over the medium term, and the residential segment 12%. The growth in these segments should be driven by FITs in Japan and Europe, and self-consumption models and state-level incentives in Australia (see Box 2.3, "Rooftop solar PV in Australia") and the United States.

Figure 2.21 Solar PV capacity and deployment by market segment



Overall, Asia (including China) represents close to 63% of global solar PV capacity growth with 202 GW of new additions over 2015-21, led by China, India and Japan. In 2021, **China's** cumulative grid-connected solar PV capacity is anticipated to reach 160 GW. The country's cumulative solar PV capacity should represent around 30% of global installations in 2021, while the country's outlook is guided by an expected annual market of 17 GW to 27 GW. With these additions, China's total solar PV capacity is expected to surpass that of the European Union in 2019, becoming the largest solar PV market globally. Utility-scale projects should dominate new additions driven by the country's attractive FIT. However, grid integration may continue to pose a challenge to this outlook. It is expected that new deployment will start shifting slowly to demand centres where the FIT is higher and curtailment risk is lower. For distributed projects, the financing of commercial-scale PV projects remains a significant barrier, with banks concerned over the creditworthiness of some project owners (or the off-taker in the case of third-party ownership) and potential asset recovery issues.

Figure 2.22 Solar PV annual capacity additions, historical and forecast by region (GW)



In Japan, solar PV is expected to expand by 26.5 GW over the medium term to reach over 60 GW in 2021, driven by generous FIT levels despite recent tariff reductions. The annual deployment pattern should be volatile with strong growth seen in 2016-17, as developers are expected to rush connecting their plants in order to keep their FIT eligibility. This report expects that many projects that received FIT eligibility in 2012-13 but do not have grid connection will be cancelled. Thus, deployment is expected to slow significantly after 2018, resulting in a dip in annual additions in Asia. **In India**, national and state-level auctions for utility-scale projects should drive the growth with 38 GW of new capacity expected to come on line over 2015-21. Despite some policy improvements both at national and state levels and price reductions observed in recent auctions, India's solar PV growth is not fast enough to reach its ambitious 100 GW target by 2022. This is due primarily to challenges concerning the financial state of utilities, low implementation of federal renewable purchase obligation targets, project delays and grid connection.

Box 2.3 Rooftop solar PV in Australia

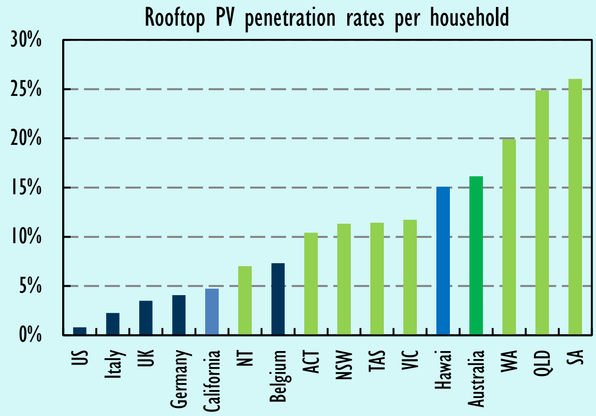
Australia ranks as the number one country globally with the highest deployment rate of rooftop PV, with over 1.5 million systems (16% of all households equipped). In Queensland and South Australia, solar PV installations per dwelling reach 25% (30% of detached and semi-detached houses), while in some suburbs of Brisbane and Adelaide (the capitals of these states) rooftop solar PV is installed on every other house (Figure 2.23). Australian rooftops also support nearly 1 million solar water heating devices.

Despite this performance, Australia ranks sixth in overall PV capacity per capita, following Germany, Italy, Greece, Japan and Belgium. Australia ranks eighth in the world with respect to solar PV's contribution to total electricity generation at 2.5% in 2015. This is due to the fact that 85% of Australian solar PV capacity consists of small rooftop systems while in other countries, the share of residential systems as a part of total solar PV capacity is relatively smaller – a fourth in Japan and Germany and even less in Greece and Italy. In Belgium only, the share of rooftop solar is around 72%, but with a population about half that of Australia, and electricity consumption at only a third.

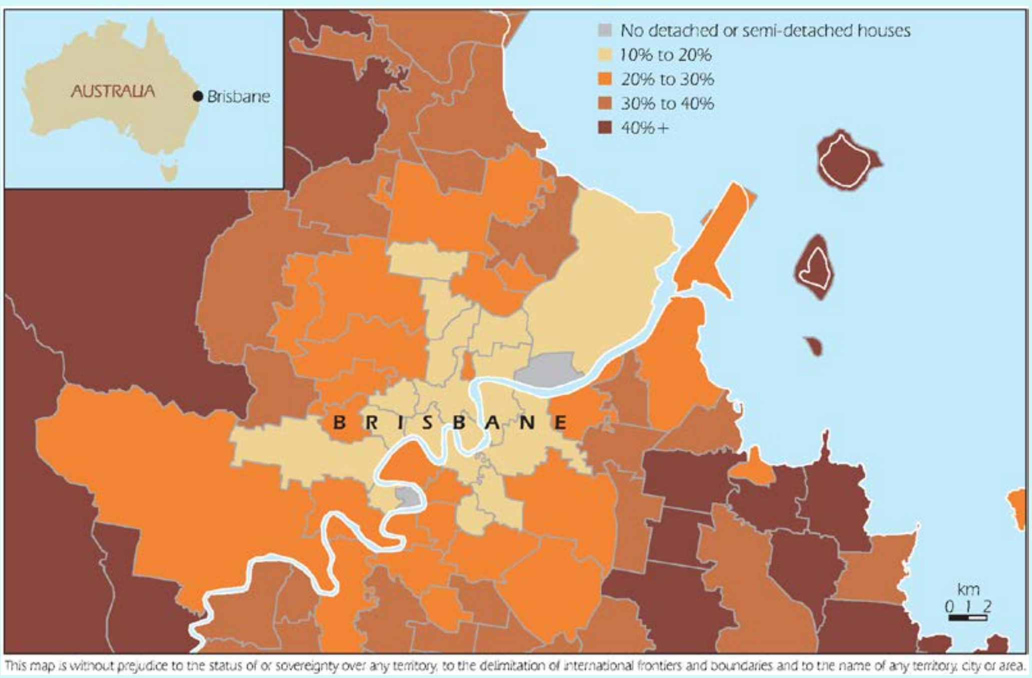
Installation began in 2009 and peaked in 2011 (for system numbers) and 2012 (for capacity) driven by state-level FITs and tax incentives – but for small systems only. After the early schemes were discontinued, a new scheme was introduced, the Small-Scale Renewable Energy Scheme (SSRES). Installations by numbers decreased from 352 000 in 2011 (with individual capacity of systems capped at 1.5 kW) to 137 000 in 2015 (with an average capacity of systems of 4.2 kW in the residential sector and 4.9 kW in total). This is driven by the rapidly growing share of commercial systems (up to 100 kW), reaching 20% of capacity installed in 2015.

Box 2.3 Rooftop solar PV in Australia (continued)

Figure 2.23 Rooftop penetration rates per household in Australia with international comparison



Rooftop PV penetration rates in Brisbane, Australia



Notes: The figure (left) shows the percentage of number of residential rooftop PV systems over the number of dwellings in selected countries or States/territories. The map (right) shows the percentage of residential rooftop PV systems over the number of detached or semi-detached houses in the area of Brisbane, Queensland, Australia. SA = South Australia; Qld = Queensland; WA = Western Australia; VC = Victoria; Tas = Tasmania; NSW = New South Wales; ACT = Australian Capital Territory; NT = Northern Territory.

Map source: APVI (2016), Mapping Australian Photovoltaic installations

Under the SSRES, small-scale technology certificates can be created with new systems delivering electricity or hot water. Each certificate represents 1 MWh equivalent to the estimated electricity that will be generated or displaced over the lifetime of the system. In 2015, around 16 million certificates were created. Residential solar PV systems received the majority of certificates (89%) followed by solar water heaters (9%) that were installed over 2014-15. Liable entities, mostly electricity retailers, were required to procure and surrender 20.6 million small-scale technology certificates in 2015, or approximately 12% of the electricity they bought

Box 2.3 Rooftop solar PV in Australia (continued)

This percentage is calculated each year based on the estimated amount of certificates to be created, the excess or shortfall from previous years, and the estimated electricity demand of liable entities – accounting for exemptions for energy-intensive trade-exposed activities. Thus, the SSRES has no strict quantitative objective but a “national”, uncapped target of 4 000 gigawatt-hours (GWh) and adjusts to markets. Certificates can be traded through a clearing house at a fixed price of 40 Australian dollars (AUD), or on the open market with lower prices. If necessary, the Clean Energy Regulator can create additional (but temporary) certificates so the fixed price effectively caps the price of certificates. In practice, their sale covers one-third of the investment in rooftop PV systems (AUD 11 300 for a 5 kW system in 2016).

A mature solar PV market with a competitive supply chain leading to low prices, a support scheme covering one-third of the investment, and high retail electricity prices explain the robustness of the rooftop solar PV market in Australia. In the absence of net energy metering provisions, self-consumption is the main driver, with a relatively good match between generation and peak demand, which is driven by air-conditioning loads in the summer. Energy exported to the grid is paid at the value of the wholesale price (around AUD 50/MWh in 2015), while the variable component of the retail tariff avoided with self-consumption is worth AUD 150/MWh to AUD 250/MWh depending on the location and average consumption. The payback period for residential PV systems – a quite rough but popular proxy for profitability – ranges from six to ten years in the various states and territories, assuming 50% self-consumption (Green Energy Markets, 2016).

Prosumers would like to increase their level of self-consumption, and global companies in battery storage are watching Australia’s market closely. The Energy Networks Association expects the cost of solar panels to fall by one-third in the next ten years while battery storage costs can fall by almost two-thirds, creating the potential “for increased cross-subsidies among customers if the cost-reflectivity of tariffs is not addressed” (CSIRO and ENA, 2015).

As in other countries, Australian network operators face concerns about their revenue shrinking as electricity demand stalls. They would support tariff modifications geared toward higher fixed or power-related components and lower variable energy. The electricity demand in Australia has declined in the past few years, even accounting for self-generation. This means the demand met by the grid and centralised generation was shrinking faster. However, concerns about cross-subsidies tend to vanish when distributed generation is made accessible to all. For example, electricity retailers, many of which are also involved in conventional electricity generation, established novel policies in order to support further rooftop deployment with a broad range of business models including third-party financing and leases.

Retail tariffs may evolve towards a greater share of fixed and peak-power related components, and a lower share of volumetric components, marginally affecting the profitability of rooftop solar PV. However, stakeholders do not expect that the tariff will change drastically, which would severely damage the business case for rooftop solar. The expansion of solar PV under these conditions is expected to continue, while stakeholders modify their business models. Electricity retailers started to include solar offers in order to keep their clients (20% of Australians change retailer every year). Network owners, such as TransGrid on its Sydney West site, demonstrate that distributed PV generation combined with storage and demand-side management can help reduce peak demand – the primary determinant of network costs – by up to 50%.

While the residential market may reach saturation in Queensland and South Australia, solar PV system upgrades and the rise of the commercial market are expected to drive growth of distributed capacities looking ahead. The average penetration of solar PV and wind together reached over 40% of electricity consumption in South Australia, a state weakly connected with the rest of the National Energy Market, where the last coal-fired power plant switched off in early May 2016.

In **the United States** solar PV capacity is expected to grow by 51.5 GW over 2015-21. The outlook is more positive versus *MTRMR 2015* primarily due to the long-term extension of the ITC. Accordingly, projects from all segments are eligible to benefit from the 30% tax credit if they commission their projects before the end of 2020. Therefore, this forecast expects annual deployment to reach 10 GW in 2020. However, the evolution of net metering rules and electricity rate design in some states raises a number of uncertainties over the scale-up of distributed PV over the medium term.

In the European Union, solar PV is expected to expand by more than 27.5 GW over 2015-21. **Germany** and **France** together represent 52% of this growth, followed by the United Kingdom and Italy. The European Union's annual solar PV additions have continued to decrease dramatically since 2011 due to policy changes that significantly reduced incentive schemes in many countries, resulting in boom-and-bust deployment cycles in Italy, Bulgaria, Romania, the Czech Republic, Spain, Greece and Croatia. Over the medium term, annual additions are expected to settle around 4 GW to 5 GW. For utility-scale projects, tenders in Germany and France (also for large commercial installations) can drive future growth. Deployment in the distributed segments will depend on the evolution of debates in a number of countries over the allocation of fixed network charges under net metering schemes and self-consumption. Outside the European Union, **Turkey's** solar PV capacity is expected to grow by over 4 GW over 2015-21, driven by FITs. The majority of this growth is anticipated to come from 0.2 kW to 2 MW of ground-mounted and commercial rooftop projects, while larger utility-scale projects are forecast to contribute after 2018-19.

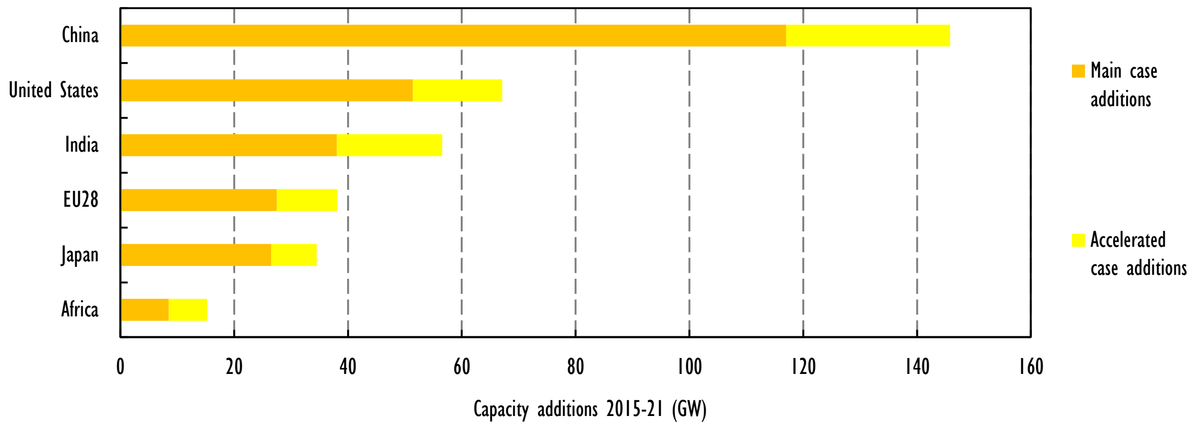
In Brazil, capacity is expected to increase by 3.4 GW supported primarily by energy auctions held in 2014 and 2015 for utility-scale projects. However, delays are expected as some projects face financing challenges under current macroeconomic conditions. In the Middle East and Africa, the majority of new solar PV capacity is expected to come from utility-scale projects under government-administrated renewable energy auctions/tenders. South Africa is expected to increase by almost 2.4 GW primarily due to large-scale projects under the Renewable Energy Independent Power Producer Procurement Programme (REIPPPP), despite grid connection delays. Notable additions are expected in Algeria, Cameroon, Egypt, Ethiopia, Jordan, Morocco and the United Arab Emirates.

Market outlook: Accelerated case summary

Under the accelerated case conditions described in the regional sections of Chapter 1, global cumulative solar PV capacity can reach 582 GW to 654 GW in 2021. This would imply a world annual market of 60 GW to 70 GW by 2021, with the range reflecting uncertainty of the enhancements occurring in concert both within and between markets. Achieving accelerated deployment would require alleviating some of the challenges enumerated above and repeated in this report. These include the rapid clarification of policy uncertainties in some markets; the implementation of stable and sustainable policy frameworks that give greater certainty about the long-term revenue streams of renewable projects; greater measures to ensure the grid and system integration of variable renewables; the implementation of fair rules and appropriate electricity rate design for allocating the costs and benefits from fast-growing distributed solar PV; and improved reductions in non-economic barriers.

Under the accelerated case, the largest growth belongs to China, India, the United States and Japan (Figure 2.24). **In China**, faster-than-expected uptake in distributed systems could translate into an additional 10 GW to 30 GW of solar PV by 2021 compared with the main case. In particular, the risks associated with distributed solar PV development may require measures to facilitate access to attractive financing and stronger incentives to make projects bankable. **In India**, greater timeliness and predictability of government auctions, an expansion of distributed solar PV frameworks, stronger expansion and upgrade of the grid, and better financing conditions could result in the deployment of 10 GW to 20 GW more by 2021. **In Japan**, rapid progress in implementing overarching electricity reforms, reducing non-economic barriers, and achieving a stronger build-out of the grid and other forms of flexibility, such as storage, could help solar PV capacity reach 5 GW to 8 GW higher in 2021 than under the main case. **In the United States**, solar PV capacity could reach 6 GW to 16 GW more by 2021, with greater-than-expected uptake in the residential and commercial sectors spurred by more favourable conditions for deployment under self-consumption.

Figure 2.24 Solar PV capacity additions over 2015-21 for selected markets



Bioenergy for power

Compared with other renewable technologies, bioenergy presents an additional level of complexity due to the range of different bioenergy power generation technologies, as well as the variety of biomass fuels and feedstocks used. As a result, this section includes market analysis for both bioenergy technologies and wood pellet markets. It should also be noted that within the *MTRMR*, bioenergy encompasses electricity generation from waste fuels.

Bioenergy costs

The variety of different bioenergy technologies in the power sector results in a great disparity of associated investment and generation costs. Even when considering the same bioenergy technology, these span a wide range globally (Table 2.5), depending on capacity e.g. as a result of economies of scale, level of technical sophistication, and locational factors such as the cost of capital and compliance with applicable regulatory regimes. Furthermore, for co-generation[2] plants the pattern of

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

heat off-taker demand will also affect generation costs. Conversely, for those technologies with more uniform capital and fuel costs such as low-level co-firing or landfill gas plants, less variation in generation costs is observed. Many bioenergy technologies are considered mature and therefore offer limited scope for further cost reductions and generally, and especially at larger capacities, project costs are bespoke according to the specifics of the plant and fuel/feedstock used.

Table 2.5 Reference global investment cost and LCOE ranges for bioenergy power technologies

Bioenergy technology type	Investment cost (USD/kW)	LCOE (USD/MWh)	Comment on investment costs
Biogas	1 000-8 500	50-190	Average biogas investment cost in Europe USD 3 500-5 500. Lower-end investment costs refer to Asian countries, e.g. China, India & Thailand.
Coal-to-biomass conversion	350-1 800	Not available	Costs are highly bespoke to each project. The use of steam-exploded pellets resulted in investment costs of around USD 50/kW in one project.
Dedicated biomass electricity	800-4 500	80-200	The lowest investment costs are generally found in India for plants fuelled by agricultural residues.
EfW	2 600-8 000	40-220	Higher-end costs in Europe and Japan, lower-end costs in China and Thailand.
Gasification	2 000-8 000	50-250	Covers technologies using a range of feedstocks such as municipal wastes, black liquor, and agricultural and forestry residues.
Landfill gas	1 800-2 300	40-90	The investment cost range is more uniform over different regions than observed for other bioenergy technologies.
Low-level co-firing	260-600	40-120	Refers to <10% biomass shares by energy combusted in coal power plants.

Notes: Costs are indicative, and ranges reflect the system cost, fuel/feedstock and finance differences among countries. Range boundaries may not be illustrative of the cost level at which the majority of deployment is occurring. Furthermore, specific project investment or LCOE values can be above or below ranges provided. Co-firing costs refer to use of biomass fuels in existing coal plants. For landfill gas plants it should be noted that as gas production varies over the lifetime of the landfill, adjustments to the number of gas engine modules may be required, with a consequential effect on project costs.

While there are discrepancies in investment costs for a given technology between regions, e.g. investment costs for biogas plants in China and India can be half of those in Europe, these technologies are often not comparable like-for-like. Higher investment costs found in regions such as Europe and North America are generally linked to more advanced bioenergy technologies that offer higher availability and efficiency as well as reduced O&M requirements, all of which favourably affect generation costs. It should be noted that since LCOE results do not take into account the value of electricity produced (determined according to the time and location of generation), making direct LCOE comparisons between variable renewable energy (VRE) and bioenergy technologies may be misleading.

In 2015, bioenergy technologies were included in auctions undertaken in Brazil, South Africa and the United Kingdom. In Brazil, two PPA renewable energy auctions awarded a combined total of 575 MW of bioenergy capacity to come on line in 2018 and 2020, in the range of BRL 211 per MWh to BRL 275/MWh (USD 60/MWh to USD 90/MWh). Lower end costs were attributable to projects fuelled by agricultural residue (bagasse and rice husk). In South Africa, one 25 MW plantation forestry-fuelled project was awarded a PPA at 1 450 rand (ZAR) per MWh (USD 121/MWh), for delivery in 2018.

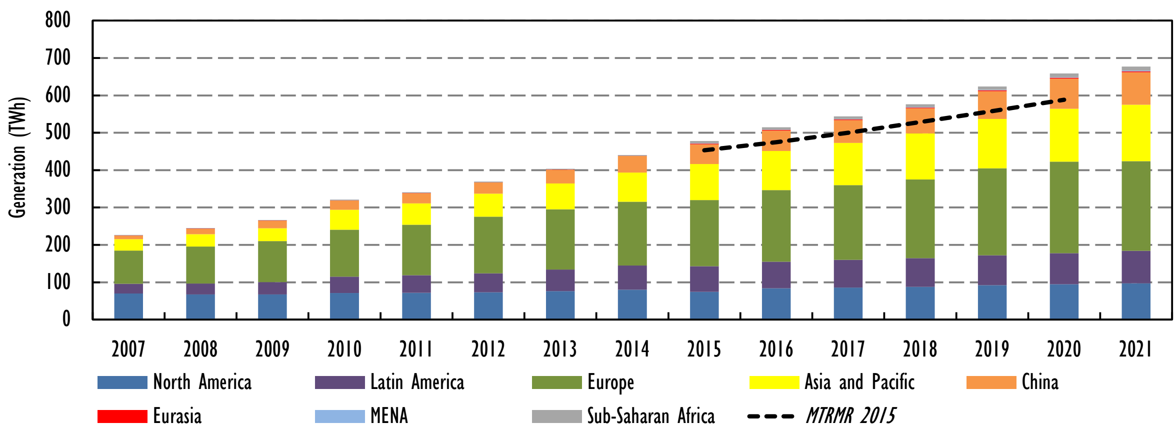
In the United Kingdom, the initial auction for 15-year CfDs awarded 540 MW of gasification projects and energy-from-waste (EfW) co-generation projects for delivery during 2018 at between 84 pounds (GBP) per MWh and GBP 126/MWh (USD 129/MWh to USD 193/MWh). In addition, confirmation was also provided later in the year of CfD investment contracts (not awarded at auction) for one coal-to-biomass conversion plant of over 400 MW capacity at GBP 114/MWh (USD 174/MWh) due in 2017 and a biomass co-generation plant of almost 300 MW capacity at GBP 132/MWh (USD 202/MWh) to come on line in 2018.

The transition towards auctions and competitive bidding for renewable energy support in many countries is likely to focus deployment on those bioenergy technologies in the power sector that benefit from lower investment costs and have access to a competitively priced fuel supply. However, the ability of bioenergy technologies to contribute to wider policy objectives such as rural development, waste management or security of supply[3] should still be a driver for deployment in many countries and regions.

Market status and outlook: Main case summary

In 2015, global bioenergy power generation was 474 TWh, an 8% increase on 2014 levels. By 2021, bioenergy generation is forecast to grow at an annual average growth rate of 6% to reach around 670 TWh, an upward revision on the *MTRMR 2015* (Figure 2.25). In 2015, the United States remains the largest generator of electricity from bioenergy (69 TWh), followed by China (53 TWh) and Germany (51 TWh). Some of the fastest average annual growth rates in major markets for bioenergy generation over the medium term are found in Asia, with leading countries including Thailand (9%), China (9%) and Japan (8%).

Figure 2.25 Bioenergy power generation, historical and forecast, by region (2007-21)



Source: Historical data based on IEA (2016a), *World Energy Statistics and Balances 2016* (database), www.iea.org/statistics/.

In **the United States**, bioenergy generation is expected to grow at an average annual growth rate of 3% over the medium term, reaching about 84 TWh in 2021. This represents a slight upward revision

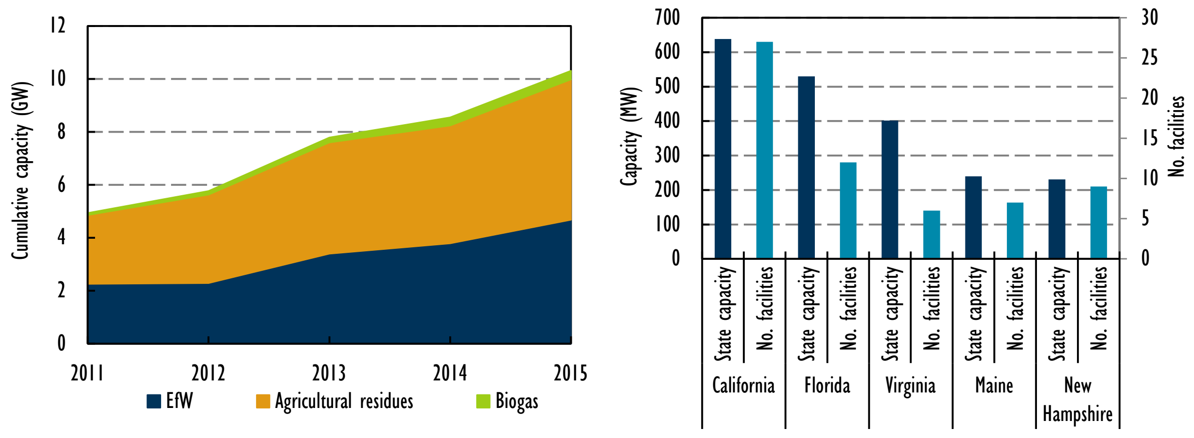
[3] This is particularly relevant to the ability of domestic biomass resources to offset natural gas consumption for power generation and particularly heat demand.

of the *MTRMR 2015.* Annual bioenergy capacity additions are expected to be stable in the range of 200 MW to 350 MW until 2021. However, the extension of the PTC[4] for biomass and landfill gas technologies, with the requirement that construction commences before 2017, should result in higher annual capacity additions over the first half of the medium term. However, uncertainty is associated with the limited timescale for biomass projects to obtain the necessary regulatory compliance permits and secure fuel supply agreements to move into construction before 2017.

Biomass is recognised within the Clean Power Plan (CPP) by the US Environmental Protection Agency (EPA), and individual states will have flexibility to determine the role of bioenergy in their implementation plans within the context of the US EPA's Framework for Assessing Biogenic CO_2 Emissions from Stationary Sources. However, there is still uncertainty regarding the exact role for bioenergy both within the CPP generally and also in individual states. Although the largest source of biomass power generation remains industrial facilities such as pulp and paper mills, Virginia has a programme to convert coal plants to biomass in line with the state's goal of 15% of electricity from renewable sources by 2025 (US EIA, 2016b). The country's largest capacity EfW plant came on line in Florida during 2015 with the state containing one-fifth of national EfW capacity (US EIA, 2016a).

Bioenergy generation in **China** increased 19% y-o-y in 2015, and it is anticipated to become the global leader in bioenergy generation by 2021 with output around 87 TWh. However, this is a downward revision of the *MTRMR 2015* forecast, reflecting the proposed reduction of the target for biomass power capacity in 2020 within the 13th FYP to 15 GW.[5] However, current deployment rates mean this new target is likely to be exceeded. Bioenergy in China is dominated by EfW and agricultural residue (mainly straw) generation as shown in Figure 2.26. These both benefit from unified national FIT support of 0.75 Yuan renminbi (CNY) per kWh (USD 0.12/kWh) for agricultural and forestry waste and residues and CNY 0.65/kWh (USD 0.10/kWh) for EfW.

Figure 2.26 Bioenergy capacity breakdown in China (2011-15) (left) and capacity and number of facilities for selected states in the United States in 2015 (right)



Note: EfW capacity in China is considered to reflect the total capacity and not prorated to adjust for non-renewable content of waste.

Sources: China National Renewable Energy Centre (CNREC) (16/03/2016), conversation with author; United States Biomass Power Association (2016), *U.S. Biomass Power Facilities*.

[4] The ITC was also re-introduced for biomass and co-generation technologies.

[5] The 12th FYP target was 30 GW.

Europe accounted for over a third of global bioenergy generation in 2015, and the region will continue to lead bioenergy generation over the medium term with annual average growth of 5%. In **Germany**, where biogas accounts for the majority of installed capacity, bioenergy generation is set to increase to 54 TWh by 2021 and is revised upward from the *MTRMR 2015*. Prospects are boosted as a result of the anticipated introduction of 100 MW to 150 MW of bioenergy capacity in annual feed-in premium auctions until 2019, rising to 200 MW for the rest of the medium term. Within the main case, new plants are not anticipated to account for all of the annually tendered capacity, as existing plants nearing the end of their FIT support will also be eligible to apply.

In **Poland**, bioenergy generation is expected to increase from 10 TWh in 2015 to 25 TWh by 2021. New renewable energy auction requirements in Poland, which entered into force in July 2016, should favour bioenergy technologies due to the creation of dedicated auction "pots" for EfW and projects with a minimum capacity factor of 40%,[6] and therefore there is an upward revision of the *MTRMR 2015* forecast. In addition, an amendment to limit the electricity purchase obligation requirement to electricity generated by renewable plants with capacity less than 500 kW will not apply to biogas plants, supporting their attractiveness relative to other renewable technologies. The introduction of an amendment requiring biomass fuels to be sourced within 300 kilometres (km) from the point of use may limit the contribution from biomass fuel imports to power generation.

Table 2.6 Bioenergy capacity forecast by region (GW)

	2014	2015	2016	2017	2018	2019	2020	2021
North America	15.8	17.0	17.4	17.8	18.2	18.5	18.8	19.1
Latin America	16.7	17.9	18.6	19.2	20.0	20.7	21.5	12.2
Europe	36.4	38.1	39.4	41.6	43.0	44.8	45.8	46.8
Asia (ex. China) and Pacific	17.8	19.2	20.6	22.2	24.1	26.0	27.8	29.6
China	9.5	10.3	11.7	13.0	14.4	15.7	17.1	18.4
Eurasia	0.4	0.4	0.4	0.5	0.5	0.6	0.6	0.6
MENA	0.1	0.1	0.2	0.2	0.3	0.3	0.4	0.4
Sub-Saharan Africa	1.5	1.6	1.7	1.8	1.9	2.2	2.5	2.8
World	**98.2**	**104.5**	**109.9**	**116.3**	**122.4**	**128.9**	**134.4**	**139.9**

Sources: Historical data based on IEA (2016d), *Renewables Information 2016* (database), www.iea.org/statistics/; Platts (2016), *World Electric Power Plants Database*; IRENA (2016b) *Renewable Capacity Statistics 2016*.

In the **United Kingdom**, bioenergy capacity increased strongly in 2015 with EfW plants the main contributor to deployment. Furthermore, the partial conversion of a 645 MW capacity coal generation unit to co-fire biomass at high percentages was also completed in 2015. The closure of the Renewables Obligation in 2017 should reduce the pipeline of bioenergy projects. However, two large-scale (299 MW and 420 MW) bioenergy projects have been awarded CfDs and are anticipated to deploy over the medium term. As a result of increased certainty regarding these projects, the forecast is revised up from the *MTRMR 2015*, and generation is forecast to reach 40 TWh by 2021. The deployment for emerging technologies such as gasification will depend on their performance in the three forthcoming CfD auctions proposed before 2020.

[6] Determined on the basis of 3 504 MWh of generation per megawatt of capacity per annum.

Table 2.7 Phase-out of coal capacity in selected EU28 countries

Country	Announcements regarding phase-out of coal
Austria	Coal potentially phased out by 2025. Of three plants, one closed in 2016, another announced it will go fossil fuel-free by 2020 and the final has announced it will go off line by 2025.
Belgium	Now coal-free after the closure of the last operational coal plant in 2016, which has since been sold to a biomass pellet producer for coal-to-biomass conversion.
Netherlands	The minimum required efficiency for coal-fired power plants increased to 38% in 2016 and will rise to 40% on in 2017, which is anticipated to lead to the closure of a number of plants. The Dutch government has also stated its intent to research the closure of further coal plants. Biomass co-firing is included within the SDE+ (Promoting Sustainable Energy Production) subsidy scheme and could be employed in several remaining plants.
United Kingdom	Announcement made in 2015 to close all unabated coal-fired plants from 2025, and restrict their use from 2023. Several coal-to-biomass conversions already delivered and one plant is in receipt of a CfD for future conversion.

In **France** bioenergy generation is anticipated to increase from 5.5 TWh in 2015 to 6.7 TWh by 2021. A 150 MW coal-to-biomass conversion project is anticipated to commission in 2016, and medium-term deployment will also be supported by annual auctions for 60 MW of co-generation capacity over 2016-18. In **Spain**, the delivery of projects associated with the 2016 auction for 200 MW of bioenergy capacity is expected to see generation increase 7% over the medium term to reach just over 6 TWh in 2021. In **Denmark** bioenergy generation is anticipated to increase to 7.4 TWh by 2021 as a number of large coal-to-biomass conversion co-generation projects come on line. These principally serve district heating networks and are fuelled by imported wood chips. Bioenergy generation in **Sweden** is forecast to reach 12.5 TWh in 2021, with the forecast driven by large-scale municipality co-generation projects that also provide district heat, including a 130 MW electricity (280 MW thermal capacity) plant that came on line in Stockholm in 2016. The phase-out of coal generation capacity in several European countries also creates opportunities for coal-to-biomass conversion projects (Table 2.7).

Some of the most robust medium-term growth in bioenergy is expected within Organisation for Economic Co-operation and Development (OECD) Asia. Bioenergy generation in **Korea** is anticipated to increase from 5.6 TWh in 2015 to 13.7 TWh in 2021 due to an increase in both dedicated bioenergy capacity and biomass co-firing. Considering recent trends, it is expected that generation from biomass co-firing will continue to grow over the medium term as a result of state-owned power generation companies' co-firing activities[7] to support RPS compliance (see 'Biomass wood pellets for power generation: Market status and outlook' section). However, the government has recently introduced a voluntary implementing plan in order to achieve a more diversified expansion of renewable technologies, the implementation of which could alter the bioenergy generation forecast presented in this report.

In **Japan**[8] a sharp increase in bioenergy generation from 36 TWh in 2015 to over 58 TWh by 2021 is expected, a significant upward revision from the *MTRMR 2015* forecast. As bioenergy technologies are not subject to grid capacity restrictions, project pipelines approved for 20-year support under the FIT scheme indicate in the region of 2.4 GW of capacity additions over 2015-21. FIT support for

[7] Besides wood pellets, co-firing also includes liquid biofuels.
[8] Please note that due to the availability of new data sources the baseline for bioenergy capacity in Japan has been revised up.

bioenergy is available within five categories according to biomass origin and in some cases capacity. For example, forestry residues used in plants of greater than 2 MW capacities attract a rate of 32 yen (JPY) per kWh (USD 0.26/kWh), EfW JPY 17/kWh (USD 0.14/kWh) and waste wood JPY 13/kWh (USD 0.10/kWh).[9] Co-firing of biomass is also eligible for FIT support and is on an upward trend (see *Biomass wood pellets for power generation: Market status and outlook* section).

Strong medium-term growth in bioenergy generation is also expected from emerging economies. In **India**, generation stood at 28 TWh in 2015 with annual bioenergy capacity additions more than doubling y-o-y. Generation is anticipated to increase by 40% to over 39 TWh by 2021, consistent with the *MTRMR 2015*. Prospects for growth are boosted by the clear role for biomass outlined in India's Intended Nationally Determined Contribution (INDC), which includes a 10 GW target for 2022, potential for bioenergy to provide energy access and also opportunities to maximise bagasse generation from within the sugar industry in cases where access to low-interest finance is available.

Biomass resources pose no constraint on growth as India's significant agriculture sector creates abundant volumes of agricultural residues. However, storage (essential due to production seasonality) and the logistics of collection and transportation of dispersed resources pose challenges in project development. Incidences of fuel price escalation for completed projects and State Electricity Board off-taker risk pose downside risks to the forecast.

In **Brazil**,[10] bioenergy generation is forecast to grow from 48 TWh in 2015 at an annual average growth rate of 4% over 2015-21 to reach just over 60 TWh, consistent with the *MTRMR 2015*. A global high of over 900 MW of new bioenergy capacity came on line in 2015. Bioenergy deployment is underpinned by large-scale co-generation plants fuelled by biomass co-products primarily serving industrial heat and power loads. Bagasse capacity not linked to energy auctions may be delivered by the sugar and ethanol industry, although investment in the sector has been on a downward trend. In addition, the fragile economic state of many sugar mills that generate electricity from bagasse poses downside risk to the forecast.

In **Thailand**, where bioenergy is considered a valuable means of improving energy access, just under 9 TWh of bioenergy generation was delivered in 2015, and this should grow strongly at an annual average growth rate of 9% to reach just under 15 TWh by 2021. The 2015 Alternative Energy Development Plan includes ambitious long-term targets for more than 6.6 GW of EfW, solid biomass and biogas deployment by 2036, which should boost deployment during the medium term. Industrial-scale biogas applications are financially competitive and have deployed strongly aided by access to affordable finance. However, some negative public perceptions towards bioenergy and EfW technologies have arisen due to previous projects failing to perform to anticipated standards, and therefore improved community consultation will be required to realise bioenergy's growth potential.

In **Indonesia** bioenergy generation is seen reaching just under 9 TWh by 2021. Bioenergy is considered a key means of offering energy access to the country's large rural population in accordance with government targets to increase electrification from 85% in 2015 to near 100% by 2020 (ADB, 2016). As such, biogas FIT rates are subject to a multiplier based on location and are

[9] The full range of bioenergy fuels included within the FIT are: EfW, methane gas, waste wood, forestry residues (separate rates for plants <2 MW and ≥2 MW) and general woody biomass.
[10] Please note that the baseline for bioenergy capacity in Brazil has been revised up.

considered attractive. Non-location-specific landfill gas and EfW FITs are also anticipated to spur some deployment, especially given waste management challenges associated with population growth and increasing urbanisation trends. The production of effluent from palm oil mills offers significant potential for industrial biogas deployment, but challenges associated with access to finance, planning and regulatory compliance have constrained uptake.

By 2021 global bioenergy power generation capacity will grow from 105 GW in 2015 at an annual average growth rate of around 5% to around 140 GW by 2021. This represents an upward revision on the *MTRMR 2015* forecast, although annual average growth is anticipated to be slower than over 2009-15 (8%). The brighter outlook is as a result of upward revisions in the United States, the United Kingdom, Germany and most significantly Japan, offsetting a downward revision for China. Some of the highest levels of bioenergy capacity additions over 2015-21 are found in emerging economies with increasing electricity demand trends such as China (8.1 GW), Brazil (3.1 GW), Thailand (2.2 GW) and India (2.1 GW). Bioenergy in Japan will also grow strongly during the medium term with 2.4 GW of additions. Capacity in Europe is expected to grow by just under 9 GW as countries seek to meet their National Renewable Energy Action Plan (NREAP) targets for 2020, led by additions in Denmark (1.4 GW) and the United Kingdom (1.5 GW).

Market outlook: Accelerated case

Under enhanced conditions, bioenergy capacity could be 9 GW to 19 GW higher in 2021 versus the main case. In **the United States** bioenergy capacity additions over 2015-21 could be 20-40% higher associated with pre-emptive CPP compliance. This is likely to need greater clarification around how biomass fuels and feedstocks can be demonstrated as "qualified biomass" and potentially a measure to incentivise early deployment of bioenergy, as is the case for wind and solar PV technologies within the Clean Energy Incentive Program. A key means of delivering higher deployment may come in the form of coal-to-biomass conversions in states that possess high levels of coal generation capacity and biomass resources. Examples include Arkansas, Iowa, Minnesota, Michigan, North Dakota, Illinois and Louisiana.

In **Germany** medium-term capacity growth could increase by around 17% provided full bioenergy capacity within feed-in premium auctions is awarded to new plants, with existing plants for which FIT support expires being suitably competitive to remain operational. In **the United Kingdom** bioenergy capacity could be higher by up to 1 GW, based on increased deployment of EfW projects supported via CfD, and further conversion of decommissioned coal plants to biomass. The latter would require allocation of funding within future CfD auctions. In **Sweden** and **Denmark** a combined 600 MW of further bioenergy capacity could be delivered through higher deployment of municipal co-generation plants fuelled by biomass and waste fuels in line with ambitious national decarbonisation goals.

In **China**, accelerated growth potential of 5 GW to 7.5 GW is associated with stronger EfW deployment primarily as a waste management solution for rapidly growing urban areas. EfW deployment holds key advantages when compared with landfills in terms of reduced land requirements, the avoidance of methane[11] greenhouse gas (GHG) emissions and energy production.

[11] Methane has a global warming potential 28 times higher than carbon dioxide (CO_2) over a 100-year timescale, according to the Intergovernmental Panel on Climate Change (IPCC) (UNFCCC, 2016a).

Realising this growth will require comprehensive consultation and communication to avoid public opposition, and steps to ensure that best available technologies are used to control emissions. This will also need to be complemented by more stringent regulation of emissions to gain public confidence. Agricultural residue projects can be supported by steps to counteract fuel price escalation such as long-term contracting or FIT flexible FIT tariffs.

Cumulative bioenergy capacity in **Brazil** could increase by up to 10% (around 1.5 GW) through future PPA auctions delivering high biomass capacity as a result of favourable criteria such as longer-term PPAs (e.g. 25 years as opposed to 20 years) and higher bid ceilings. Demand for biomass could be increased by the need to diversify Brazil's generation mix to compensate for potential weather-related hydropower shortages. An overall national plan for the biomass electricity sector could also spur higher levels of activity.

In **India** cumulative bioenergy capacity could be 16-22% higher, putting the country on a firm track to meet the 10 GW bioenergy target for 2022 stated within its INDC. Higher deployment could be delivered through the introduction of a generation-based subsidy for bioenergy, such as is available for wind, and measures to extend affordable finance to developers, especially for the sugar industry to facilitate investment in the optimisation of bagasse plants. Regular revision of biomass tariffs or the annual determination of feedstock prices based on independent surveys would protect the industry against fuel cost escalation. Furthermore, the efficiency of agricultural residue collection could be improved by the development of centralised collection and storage centres.

Indonesia could offer between 150 MW and 400 MW of additional capacity associated with the increase of FIT capacity caps for bioenergy technologies and increased tariffs within the islands of Java and Sumatra, and the expected growth in palm oil processing from the biodiesel industry boosting potential for industrial-scale biogas plants using palm oil effluent feedstocks. While not related to capacity, bioenergy generation could step up through higher co-firing in China, Japan and in the Netherlands (up to a cap of 25 petajoules per year).

Box 2.4 Flexible bioenergy plants in countries with high shares of VRE

As many countries achieve higher shares of wind and solar PV in their generation portfolios, the market dynamics for other technologies shift, with greater demand created for flexible plants able to generate during low-VRE infeed to supply residual system loads and then back down when VRE generation is high. Bioenergy technologies are inherently dispatchable. However, the ability of different technologies to operate flexibly in line with the needs of a high VRE power system varies and modifications to increase the flexibility of plants can require investment. Therefore, the prospects for flexible bioenergy technologies within high VRE power systems are defined by both technical and economic factors.

Flexible generation technologies need to modulate generation with a high degree of precision over a range of loads and timescales and with short response times. Examples of flexibility within biomass combustion technologies include utilising the turndown ratio of boilers to modulate generation, the use of liquid biofuel generators to serve peak loads, and the thermal storage of biomass co-generation plants to operate flexibly where there is a heat and power demand mismatch. Biogas systems offer a wide range of measures to increase flexibility. These include increasing the volume of gas storage and generator capacity, adapted feeding regimes to control gas production, and virtual power plant concepts to control a larger number of smaller-capacity systems in unison.

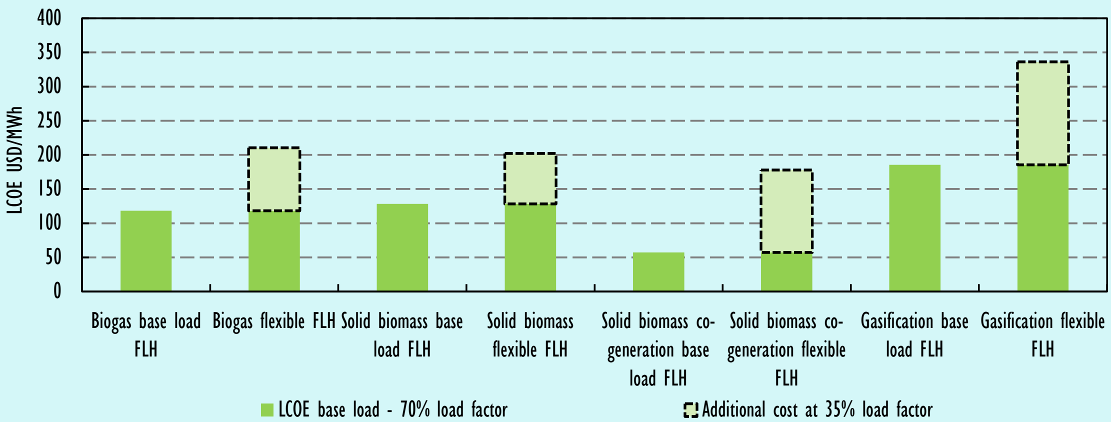
Box 2.4 Flexible bioenergy plants in countries with high shares of VRE (continued)

The ability to operate flexibly also requires consideration of economic factors. Flexible generation provides opportunities for bioenergy technologies to compete with hydropower and fossil fuel technologies to access revenue streams associated with the provision of balancing power, ancillary services and strategic generation to access peak power prices, which in Europe were on average 10% higher than base prices over 2011-15 (BNEF, 2016b). However, it will also challenge existing modes of operation for many plants as flexible operation entails reduced annual full-load hours (FLH) associated with backing down when VRE generation is high.

The capital costs of some bioenergy technologies necessitate operation over high FLH to be economically viable. This is especially relevant for less mature technologies with higher levels of investment risk and in markets where higher costs of capital are prevalent. As such, operation at reduced FLH (e.g. capacity factors of 20-45%) to cover residual loads may not be economically feasible for all plants (Figure 2.27). It should be noted that this issue is not specific to bioenergy and also applies to other forms of flexible generation. Therefore, the potential income stream from the provision of ancillary services needs to be carefully evaluated against the economic impact of reduced annual FLH.

Fuel costs are also a key consideration. Plants with lower marginal costs of generation realise lower fuel cost savings from operating at reduced FLH. With EfW plants, economic inflexibility may also exist where a gate fee is received. This results in negative fuel costs and an incentive to generate even when power prices and ancillary service income are low. Furthermore, plants using agricultural or forestry residues may face seasonal variations on fuel availability, which influences the ability to operate flexibly.

Figure 2.27 Example LCOE values for bioenergy technologies at 70% and 35% load factors



Given that operating flexibility often requires investment and a move away from traditional modes of operation, policy intervention may be needed to incentivise bioenergy technologies to cover residual loads. Examples include a premium for biogas flexibility included in the German EEG since 2012 (Szarka et al, 2013). As of early 2015, almost 3 000 plants had registered for the additional flexibility tariff (Thran et al, 2015). Other examples include incentives for biomethane injection into the gas grid in the United Kingdom, the Netherlands and Germany, and policies that delivered coal-to-biomass conversions in Canada and Europe.

There are also examples of bioenergy plants offering balancing system services. Just under 30% of solid biomass-fuelled steam and organic rankine cycle (ORC) power plants in Germany are offering flexibility, principally in the form of negative control power (Thran et al., 2015); biomass plants have participated in the United Kingdom balancing mechanism; and two Canadian coal-to-biomass conversion plants are providing backup to hydropower and variable renewable generation in Ontario.

Box 2.4 Flexible bioenergy plants in countries with high shares of VRE (continued)

In conclusion, opportunities for bioenergy to provide base-load power will still exist in many countries, but the ability of bioenergy technologies to economically contribute to meeting residual loads will influence market prospects in countries moving towards higher shares of VRE.

Biomass wood pellets for power generation: Market status and outlook

Global wood pellet demand for industrial (e.g. large-scale electricity-only and co-generation plants) and heating consumption increased by 13% in 2015 to reach just under 28 megatonnes[12] (Mt) (Hawkins Wright Ltd., 2016)[13]. The majority of the 3 Mt y-o-y increase in consumption was accounted for by the industrial market segment. Global wood pellet imports for both industrial and heat markets also increased during 2015 and were estimated at 14.6 Mt.

Imported wood pellet supply is a key consideration within the *MTRMR 2016* bioenergy main case forecasts for the United Kingdom, Belgium, Denmark, Japan and Korea, and complements domestic biomass resources in Sweden. In addition, wood pellet imports could underpin accelerated bioenergy deployment in the Netherlands and the United Kingdom. Furthermore, increased domestic consumption in Canada and the United States, both key global exporters of wood pellets, as well as Finland could also accelerate bioenergy deployment over the medium term.

Wood pellet imports to the United Kingdom are dominated by supply from the United States and Canada, with consumption of wood pellets sourced from outside Europe increasing by around 25% in 2015 to 4.7 Mt (HMRC, 2016). This continues an upward trend associated with large-scale coal-to-biomass conversions. Elsewhere in Europe the announced purchase of a large-scale coal plant in Belgium by a pellet producer company, with the aim of conversion to dedicated wood pellet use by the end of 2017, suggests a potential change in market dynamics. Consumption is also expected to increase in Denmark, Sweden and Finland over the first half of the medium term associated with large-scale coal-to-biomass, co-generation and district heating projects.

Wood pellet imports in Korea were around 1.5 Mt in 2015 (Korea Customs Service, 2016). As shown in Figure 2.28, consumption has increased since 2012 as a result of co-firing from state-owned power generation companies to support their compliance with RPS. Supply is sourced through tendering exercises that have principally awarded supply contracts to ASEAN countries, where pellet production capacity is on an upward trend. Viet Nam has emerged as a key supplier to Korea as a result of higher pellet production capacity compared with other ASEAN nations, access to waste material from the wood product manufacturing industry, and very low ocean freight costs to serve demand within Asia.

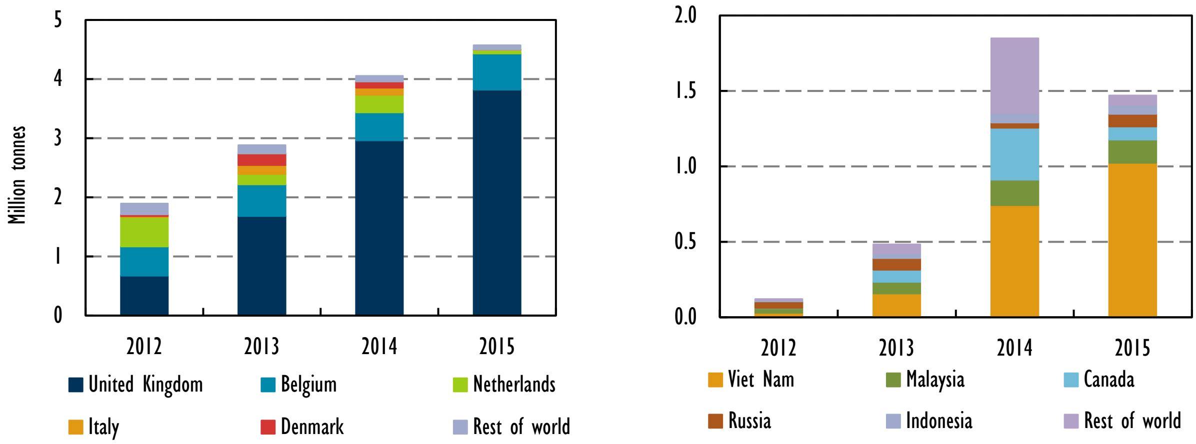
Canada is also a key supplier to Korea, although 2015 exports dropped by about one-third y-o-y, mainly due to price competition from ASEAN supply as well as lower Korean demand associated with

[12] Calorific values vary depending on specific fuel specifications. However, an approximate value for wood pellets of 17 gigajoules per tonne can be used to convert megatonne values to energy units.

[13] Wood pellet market data from Hawkins Wright Ltd. sourced via personal communication with Fiona Matthews in May 2016.

the revision of RPS[14] legislation. It remains to be seen if tenders will incorporate higher forestry certification requirements and stricter quality parameters, e.g. regarding ash content, which would allow higher co-fired percentages to be achieved. Demand should increase further in 2017 due to Korea's first coal-to-biomass conversion project (Doosan, 2016), while the use of liquid biofuels for co-firing is also included in the RPS and could scale up.

Figure 2.28 Wood pellet exports from the United States (left) and Korean imports (right), (2012-15)



Sources: United States International Trade Commission (2016), *U.S. Total Exports*; Korea Customs Service (2016), *Import/export by country*.

In Japan, where wood pellet demand increased y-o-y over 2012-15, imports jumped from just below 97 000 tonnes in 2014 to over 230 000 tonnes in 2015 (Ministry of Finance, 2016). Moving forward, demand should continue to rise strongly due to biomass deployment stimulated by the FIT scheme, complemented by co-firing in more plants and at higher percentages. In early 2016, direct Japanese investment was made in a Brazilian biomass (bagasse) pellet production company.

Overall, while international wood pellet trade can be anticipated to increase over the medium term, the market is still dominated by a relatively small number of large-capacity consumers and therefore can undergo notable changes as a result of technical or economic factors that affect demand from these plants, e.g. a plant coming off line for unplanned reasons or policy changes.

Wood pellet exports from the United States increased by 29% y-o-y in 2015, reaching around 4.5 Mt (United States International Trade Commission, 2016). This continues an upward trajectory with an average annual growth rate of 35% over 2012-15, underpinned by rising supply to the United Kingdom. In order to support increasing demand, around 2.2 Mt of additional pelletisation capacity was added in the United States during 2015. There were 107 operational wood pellet manufacturing facilities in the United States at the beginning of 2016 (Forisk, 2016), with an estimated combined installed capacity of 10.3 Mt. Prospects for increased domestic consumption associated with the CPP will be dependent on the role outlined for biomass within state authority compliance plans.

[14] RPS requirements were introduced in Korea in 2012 and established gradually increasing targets for the share of renewables in electricity generation. RPS quotas were originally established at 3.5% in 2015 and rising to 10% by 2022. The target of 10% of generation from renewable sources has since been revised from 2022 to 2024 with a consequential effect on annual quota percentage in preceding years.

Wood pellet exports from Canada have remained steady at around 1.6 Mt over 2013-15 (Government of Canada, 2015), with the United Kingdom, Korea and Japan principal consumers of pellets for power production. Reduced exports to Korea in 2015 were offset by a rise in demand from the EU28. Canada has 37 operational pellet-manufacturing plants with an estimated total installed capacity of about 4 Mt (Rebiere, 2016). Expansion of wood pellet production capacity in Canada is ongoing with plants under construction and proposed in Ontario, and a further number planned in British Columbia. Domestic consumption for power generation is aided by two converted coal plants in Ontario, and the growing market for wood pellet heating. Potential also exists for consumption by coal plants for co-firing elsewhere, particularly Alberta, where the introduction of a carbon levy from 2017 may act as a driver for biomass use, although the outlook for this is uncertain.

Wood pellet production capacity in the EU28 increased by around 2 Mt in 2015. New pelletisation plant capacity is mainly intended to serve heating markets, but pellet plants can be adapted to also supply industrial demand. Pellet production in Russia has experienced steady y-o-y growth and is now assessed at about 1 Mt (Argus Media, 2016); this could double towards the end of the medium term, aided by minimal competing domestic demand for sawmill residues. China has the potential to supply growing Korean and Japanese markets, although domestic availability of economically priced raw material supply and stiff price competition from increasing production capacity in ASEAN countries will influence export prospects. Wood pellet supply to Korea reduced significantly y-o-y from 287 000 tonnes in 2014 to just 3 000 tonnes in 2015 (Korea Customs Service, 2016), although this was balanced in part by higher exports to Japan.

European market access for wood pellet suppliers is maximised via obtaining recognised industry certifications such as Forestry Stewardship Council, ENplus and Sustainable Biomass Partnership (SBP). For example, the energy utility companies that initiated the SBP either favour or specify certification under the scheme within supply procurement. The SBP has also been evaluated and found compliant with sustainability requirements for the Renewable Obligation subsidy scheme in the United Kingdom (SBP, 2016), while scheme certification will also be used in Belgium.

Liquidity of supply markets could be enhanced through common sustainability and certification criteria alongside standardisation of quality requirements and trade terms. Furthermore, increased tradability of pellets across power and heating markets should be beneficial to both by allowing easier compensation for variability associated with unanticipated supply disruptions, weather-related heat demand and power plants coming off line expectantly. This would also facilitate increased management of pellet storage costs outside of the heating season (Argus Media, 2016).

Box 2.5 Biorefinery market developments

Biorefining, the processing of biomass into a range of bio-based products and bioenergy/biofuels, is an innovative and efficient approach to using available biomass resources for the co-production of power, heat and biofuels alongside food and feed ingredients, pharmaceuticals, chemicals, and materials.

Biorefinery facilities can be categorised as bioenergy/biofuel or product driven. Within recently constructed biorefineries, bioenergy/biofuel driven facilities are more common. In these, heat, power and biofuels are the main products, and process residues are used to produce additional bio-based products. In product-driven biorefineries, higher-value food and feed (e.g. starch, sugar) ingredients, pharmaceuticals, chemicals and/or fibrous materials (e.g. pulp, paper) are the main products, with low-quality biomass residues used for the production of bioenergy and less commonly, biofuels.

Box 2.5 Biorefinery market developments (Continued)

Assessing the number of biorefinery facilities currently in operation globally is challenging. However, as of 2014 more than 70 different demonstration, pilot and commercial-scale projects, either in operation or at various stages of development, were identified by Task 42 of the International Energy Agency (IEA) Bioenergy Technology Collaboration Programme (IEA Bioenergy, 2014). Of these, Austria, the Netherlands and Canada all had more than ten individual plant developments.

Industrial biorefineries are mainly found in the food, feed and dairy, and pulp and paper industries at the current time. In the medium term, further product biorefineries are anticipated to deploy in a variety of wider market sectors. Key opportunities for expansion relate to the conversion of existing industrial facilities to biorefineries, offering the benefit of reduced initial investment and time to market; in this respect examples of the conversion of petroleum product refineries to produce biofuels are already available with several conversion projects to produce hydrotreated vegetable oil biofuels in various stages of development.

Beyond the medium term, the portfolio of product-driven biorefinery concepts could expand further. For example, lignocellulosic feedstock, oleochemical and marine (algae) biorefineries may enter the market. However, expansion will require further technology development as product-driven biorefinery facilities are generally less technically mature than bioenergy/biofuel alternatives. In addition, current policy support is more favourable towards bioenergy and biofuels than the production of bio-based products. As such, facilitating the market development of product-driven biorefineries is likely to require more widespread policy frameworks to support bio-based products. However, since such materials are generally higher-value products than bioenergy and biofuels, expanding markets for bio-based products will be a key factor in product-driven refinery expansion.

Initiatives to support industry development include a Biorefineries Roadmap in Germany in 2012 and ongoing funding for innovative biorefinery projects from the US Department of Energy (DOE). Deployment in Europe should be boosted by the Bio-Based Industries Joint Undertaking, a partnership between the European Union and the private sector to invest USD 4.1 billion in innovative technologies and biorefineries to produce bio-based products from biomass wastes and residues. In addition, the European Commission’s circular economy package includes biomass and bio-based products as a priority sector and outlines the promotion of support to innovation in the bio-economy (Kubicki, 2016).

Bioenergy markets will play a central role in facilitating the growth of product-driven biorefineries through the development of sustainability certification processes and biomass fuel and feedstock supply chains. In addition, biofuel and biogas plants offer potential for upgrade to integrated biorefineries co-producing fuels and added-value bio-based products, with such facilities benefiting from diversified product streams and increased market competitiveness. Furthermore, even in the context of wider deployment of product biorefineries, lower-value biomass feedstocks such as agricultural and post-consumer residues that are less suitable for economic bio-based product manufacture are likely to remain destined for bioenergy markets.

Offshore wind

Technology and manufacturing development

The commissioning of large-scale projects in Europe and installation of larger turbines have marked the trend for the offshore wind market. Over the last year, European turbine manufacturers completed the construction of their new turbines in several test sites:

- In July 2015, Siemens installed its new 7 MW offshore turbine in a test field in Denmark. The turbine has passed final certification, and received its first order of 330 MW for the Walney Extension project in the United Kingdom.
- In April 2016, MHI Vestas installed its two V164-8 MW turbine for an onshore test project in Denmark. The company already signed a firm contract to deliver 8 MW turbines to the Burbo Bank Extension offshore project by 2018.
- Different parts of Adwen's new 8 MW turbine (a joint venture between AREVA and Gamesa) are being tested at the time of writing. The turbine is expected to initially supply French offshore projects, and the company is planning to build a manufacturing facility in Le Havre, France.
- With the acquisition of Alstom, GE is expected to become an important player in the market. Alstom's former Haliade 6 MW turbine will be produced by GE in France. These turbines are being installed for the first offshore wind project in the United States located off the coast of Block Island in the state of Rhode Island.

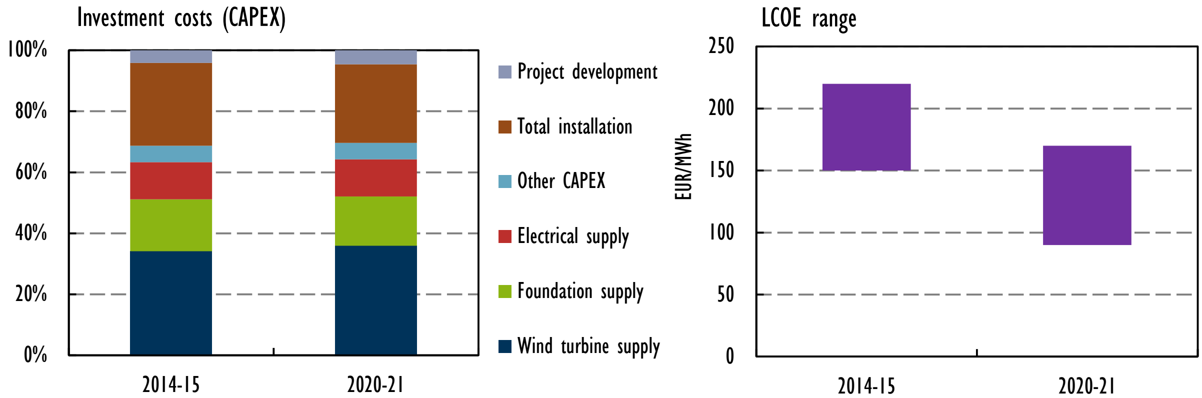
In Asia, mixed market developments were observed over the last year:

- Ming Yang installed its 6.5 MW two-blade prototype turbine for a test run in China's Jiangsu province. The turbine is expected to be installed in Norway's Marine Energy Test Centre in 2017 while the commercialisation of the turbine is expected before 2019.
- In Korea, the development of the offshore wind industry has been slow. Over the last year, large Korean companies have stopped their turbine research and development (R&D) activities. Samsung sold its test turbine located in Levenmouth, the United Kingdom, to the Offshore Renewable Energy (ORE) Catapult. However, the government initiated the tendering procedure of 60 MW of offshore wind capacity in 2016.
- In Japan, the research, development and demonstration projects are mostly focused on floating structures. Moreover, Hitachi installed its first offshore 5 MW turbine in 2015 which will be fully commissioned in late 2016.

Offshore wind investment costs vary significantly depending on the project's distance to shore and to the onshore substation, its water depth, the topography of the seabed, and grid connection time. At the end of 2015, the average water depth of operational wind farms was 27.1 m, and the average distance to shore 43.3 km in Europe (WindEurope, 2016a). In 2015, this average distance increased year-on-year primarily due to the large deployment in Germany, where offshore wind sites are located farther from the shore compared with other countries. The majority of planned projects are also expected to follow this trend. In Europe, the average project size almost doubled since 2010 and reached 338 MW in 2015 (WindEurope, 2016a). This trend is expected to continue over the medium term as the majority of projects under construction and in the development stage are between 300 MW and 750 MW. With the increasing size of projects, developers aim at taking full advantage of economies of scale, and reduce investment costs.

Total investment costs for offshore wind projects are highly variable and project-specific. In Europe, system costs for projects that became operational over the last year range from 3 700 euros (EUR) per kW (USD 4 100/kW) to EUR 4 500/kW (USD 4 995). This cost range includes both onshore and offshore electrical infrastructure required to commission a project. For projects connected to the grid in 2015, this report estimates that average total investment costs were around EUR 4 000/kW (USD 4 440) assuming 3 MW to 5 MW turbines, monopile foundations, 23 m to 30 m water depth, and 35 km to 40 km distance to shore. Turbines usually represent 35-40% of overall system costs, followed by total installation costs (30%), foundation supply (17%) and electrical infrastructure supply (13%) including substations (Figure 2.29).

Figure 2.29 Offshore wind breakdown of total investment costs and LCOE ranges



Sources: Analysis based on BVG Associates and KIC InnoEnergy (2015), *Future Renewable Energy Costs: Offshore Wind;* UK Trade & Investment (2014), *UK Offshore Wind: Opportunities for Trade and Investment;* CEP (2014), *Offshore Wind Project Cost Outlook 2014 Edition;* BNEF (2015c), *Route to Offshore Wind LCOE Target;* TKI Wind op Zee (2015), *Cost Reduction Options for Offshore Wind in the Netherlands FID 2010-2020.*

Over the project lifetime, wind turbine supply, total installation costs, O&M and financing costs represent over 75% of the LCOE. O&M costs have the largest share (around 25%) of total generation costs. Considering the number of turbines and their distance to shore, this report estimates annual O&M costs to be around 4% of the overall CAPEX. The financing rate also plays an important role in the overall generation costs. With a gearing ratio of 65% debt and 35% equity, the weighted average cost of capital for projects that came on line during 2014-15 is estimated between 7-9%, depending on the type of investors, project financing structures and investors' return expectations. Overall, capacity factors for projects connected to the grid over 2014-15 are expected to be 35-45%. Thus, generation costs for projects connected to the grid in Europe over the last year were estimated between EUR 170/MWh and EUR 235/MWh. However, it is important to note that these projects reflect the technology and final investment decisions made in 2010-12.

Going forward, offshore wind investment costs are expected to decrease significantly with the deployment of larger wind farms, increasing competition among turbine manufacturers and providers of other supply chain elements, the standardisation of some foundation structures, and more efficient O&M. Developers are moving from 3 MW to 5 MW turbine platforms to 6 MW to 8 MW platforms. The majority of projects that are expected to come on line during 2018-21 have already signed conditional or firm contracts for these new-generation turbines. Today, new-generation turbines with higher rated capacity are slightly more expensive compared with the 3 MW to 4 MW platform. However, as fewer foundations and array cables will be required, these turbines are expected to achieve a net reduction in overall construction and installation costs. This report expects total investment cost to decrease by 10-15%, ranging from EUR 3 400/kW (USD 3 775/kW) to EUR 3 900/kW (USD 4 330/kW) for projects coming on line in 2020-21, including transmission costs.

The increasing deployment of larger turbines should also result in lower generation costs. First, offshore projects should have lower O&M costs as servicing requirements decrease with fewer turbines. Second, larger rotor diameters are expected to increase the yield. Proposed projects are seen having higher capacity factors ranging from 45-50%, thus lowering generation costs significantly. In addition, new projects are expected to benefit from lower financing costs. Since 2013, the risk perception of offshore wind projects has evolved with the entry of different types of equity providers (such as pension funds and sovereign wealth funds), having lower risk appetite. Utilities have so far provided the majority of equity investment in offshore projects within Europe mostly on their balance sheets. This trend is expected to continue, but the weight of other investors is anticipated to increase slowly with a rising number of project finance deals over the medium term.

Recent offshore wind tender results in the United Kingdom, Denmark and the Netherlands offer evidence of lower generation costs over the medium term, driven by technology improvement, increasing competition and lower cost of financing. In the United Kingdom, two offshore wind projects won contracts for over 1.1 GW of capacity, offering GBP 114/MWh (EUR 156/MWh) and GBP 120/MWh (EUR 165/MWh), including transmission costs. These projects are expected to come on line in 2019-21. In Denmark, Vattenfall won the tender with EUR 103/MWh (USD 114/MWh) for 20 TWh (11 to 13 years of generation) to build the 400 MW Horns Rev 3 project, excluding transmission costs. This report estimated that the LCOE for this project including transmission costs should be around EUR 95/MWh. Horns Rev 3 is expected to be fully commissioned in 2019. In July 2016, the lowest contract price was achieved in the Netherlands, where Dong Energy offered EUR 73/MWh (USD 81/MWh) excluding transmission costs for the 700 MW Borssele offshore wind plant, which is expected to be operational in 2020-21. This average bid price was 40% lower than the ceiling price of EUR 124/MWh (USD 138/MWh) set by the government. Overall, the generation costs are estimated around EUR 90/MWh (USD 100/MWh) including all transmission costs.

Offshore wind LCOEs in Europe for projects becoming operational in 2020-21 are expected to range from EUR 90/MWh (USD 100/MWh) to EUR 170/MWh (USD 190/MWh). Projects in Denmark and the Netherlands roughly represent the lower bound, while the majority of plants in the United Kingdom, Germany and Belgium should fall in the middle of the LCOE range presented above. The first offshore wind projects contracted in 2013 in France, which are expected to be fully operational by 2020-21, are estimated to be at the higher end of the LCOE range as they are anticipated to have higher investment costs due to more difficult seabed conditions and relatively lower capacity factors compared with some plants located in the North Sea.

Market status and outlook: Main case summary

In 2015, global offshore wind generation reached an estimated 38 TWh, 50% higher than in 2014. At the end of 2015, global offshore wind cumulative capacity was 12 GW, with 3.4 GW of new capacity connected to the grid. Compared with 2014, annual additions more than doubled. This is mainly due to the commissioning of delayed projects (due to grid connection) in Germany. The European Union represented over 85% of new offshore wind capacity, with more than 3 GW connected to the grid in 2015. Germany led new installations with 2.3 GW, followed by the United Kingdom (0.6 GW) and the Netherlands (0.2 GW).

Globally, offshore wind capacity is expected to triple and reach 36.3 GW in 2021 (Table 2.8). Additions are anticipated to grow fast and peak in 2020, when the majority of projects in Europe are scheduled to come on line, leaving the project pipeline relatively empty in 2021. Overall, the share of offshore wind in global electricity generation is expected to be below 1% in 2021. Over the medium term, the cumulative capacity in the **European Union** is anticipated to reach almost 28 GW in 2021. Overall, the European Union should represent over 70% of the global cumulative offshore wind capacity, with its share in global generation likely to be higher, reaching over 80% as new projects are expected to have over 45% capacity factors.

Table 2.8 Offshore wind power capacity and forecast by region (GW)

	2014	2015	2016	2017	2018	2019	2020	2021
European Union	8.0	11.0	11.6	13.5	16.3	19.1	24.6	27.6
Belgium	0.7	0.7	0.7	0.7	0.9	1.2	1.6	1.8
Denmark	1.3	1.3	1.3	1.3	1.3	1.5	1.7	1.7
France	–	–	–	–	–	0.4	1.3	2.0
Germany	1.0	3.3	3.7	4.9	5.9	6.2	6.7	7.3
Netherlands	0.2	0.4	0.5	0.9	1.1	1.1	1.4	1.8
United Kingdom	4.5	5.1	5.1	5.5	6.7	7.8	10.6	11.4
Other EU countries	0.1	0.1	0.1	0.1	0.2	0.5	0.6	0.8
North America	–	–	0.0	0.0	0.0	0.3	0.4	0.6
China	0.7	1.0	1.4	1.9	2.6	3.6	5.1	6.8
Asia and Pacific	0.1	0.1	0.2	0.3	0.6	0.7	1.3	1.4
Other countries	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
World	**8.8**	**12.1**	**13.2**	**15.8**	**19.5**	**23.7**	**31.4**	**36.3**

Note: Rounding may cause non-zero data to appear as "0.0" or "- 0.0". Actual zero-digit data is denoted as "-".

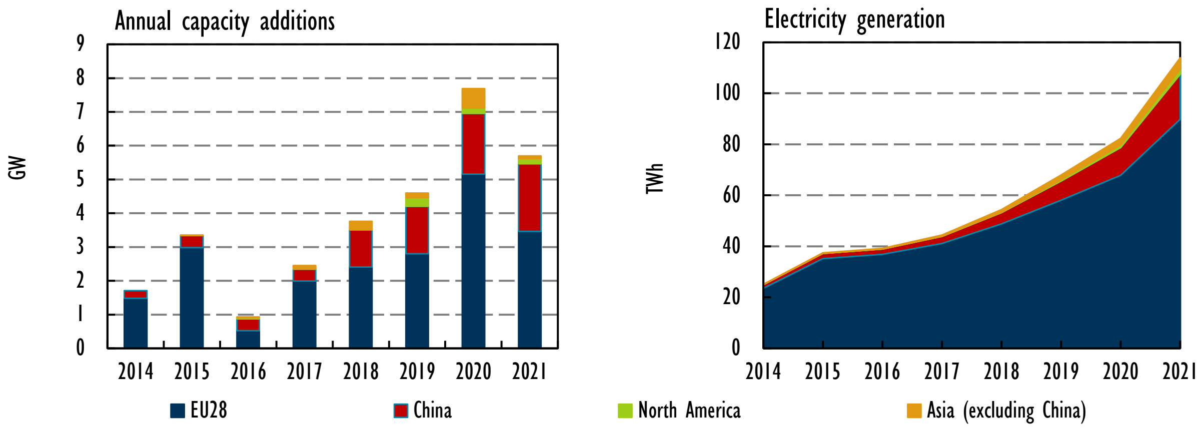
Sources: Historical data based on IEA (2016d), *Renewables Information 2016*, www.iea.org/statistics; GWEC (2016), *Global Wind Statistics 2015*; WindEurope (2016a), *The European Offshore Wind Industry – Key Trends and Statistics 2015*; IRENA (2016b), *Renewable Capacity Statistics 2016*.

With the late commissioning of the Dolwin Alpha offshore wind converter platform in early 2015, delayed offshore projects (around 0.8 GW) were connected to the grid in Germany over the last year. In August 2015, the world's most powerful offshore electrical converter station became operational on time. Three offshore wind projects (Gode Wind 1 and 2 and Nordsee 1), with a total capacity of 960 MW, will be connected to this station during 2016-17. With further improvements in grid connection and the current project pipeline under development and construction, **Germany** is forecast to reach its 6.5 GW target by 2020.

In **the Netherlands**, all foundations of the Gemini offshore wind plant (600 MW) were commissioned earlier than expected. The plant is projected to become fully operational in 2017. After the result of Borssele tender, the Dutch government is expected to hold annual tenders to contract further projects over the medium term. In **Denmark**, the energy agency accepted seven pre-qualification proposals for the 600 MW Kriegers Flak project, which is expected to be operational by 2022, two years later than initially planned. The forecast for Denmark is unchanged, and expects the commissioning of the Horns Rev 3 project over 2019-20 as planned. Overall, the Danish offshore wind capacity is forecast to reach 1.7 GW by 2021.

In the **United Kingdom**, the forecast is slightly more optimistic because of an additional project (the Galloper wind farm) in the pipeline. The government is expected to hold additional CfD auctions, but the timeline was not announced at the time of writing of this report. Two offshore projects, which signed contracts in the first quarter of 2015 in the previous CfD auctions, should close their financing during 2016-17 and start construction in 2018-19. However, the *Neart na Gaoithe* project's (448 MW) CfD incentive was terminated in March 2016 because it could not close its financing on time due to the judicial review initiated by the Royal Society for the Protection of Birds. Overall, UK offshore wind capacity is forecast to grow from over 5 GW in 2015 to 11.4 GW in 2021, representing the largest offshore wind cumulative capacity globally. France's forecast is revised up by 300 MW in 2020, as capacity from the first tender is expected to be fully operational before 2021. Thus, the country is expected to add 2 GW of new capacity over the medium term.

Figure 2.30 Offshore wind annual additions and generation forecast by region



In 2015, **China** installed 320 MW of new offshore capacity, the highest annual additions ever. With this expansion, the country reached 1 GW of cumulative installed capacity. However, China reached less than 20% of its 5 GW offshore target by 2015. The majority of offshore projects in China are developed by state-owned utilities such as Guodian Corporation. Offshore wind deployment has been slow mainly due to administrative issues on maritime zoning, the lack of experience in offshore project development and in construction, the low FIT, and high financing costs. In the beginning of 2015, NEA released the National Offshore Development Plan to prioritise projects and facilitate the permitting process. Over the medium term, China's offshore wind capacity is expected to grow rapidly from 1 GW in 2015 to 6.8 GW in 2021, though this falls short of its 30 GW target by 2020. Overall, China should represent around 20% of global cumulative offshore capacity in 2021.

Japan and **Korea** are anticipated to contribute to new additions in Asia over the medium term. The Japanese market is expected to focus on floating demonstration projects. A 7 MW (200 m height) floating demonstration project has been in operation since December 2015. Anticipated government tenders should drive the first large-scale offshore projects in Korea. In ASEAN, the first offshore wind deployment took place in **Viet Nam** with the commissioning of the Bac Lieu wind farm with Phase I (16 MW) in 2013. The second phase of this project (83.2 MW) was also installed in mid-2016.

In North America, the first offshore wind project is expected to come on line by the end of 2016. In the **United States**, the 30 MW Block Island wind farm is located 5 km from the shore in Rhode Island and will be equipped with 6 MW GE turbines (former Alstom Haliade) and jacket foundations. There are currently three other projects in the development stage with a total capacity of 36 MW. In addition, 13 projects representing around 6 GW of capacity have obtained exclusive development rights, or site control, from the government. However, this report expects only a small minority of these projects to become operational by 2021.

Market outlook: Accelerated case summary

Under the accelerated case conditions described in the regional sections of Chapter 1, global cumulative offshore wind capacity could reach 43 GW in 2021. Achieving enhanced deployment would require timely commissioning of offshore projects in Europe. More capacity could be installed with the introduction of additional tenders in various European countries such as Belgium and the Netherlands. In Asia, faster-than-expected cost reductions and faster commercialisation of floating turbines could lead to higher capacities in Japan and Korea. In China, offshore wind capacity could be 5 GW higher in 2021 with smoother administrative procedures, in addition to further cost reductions.

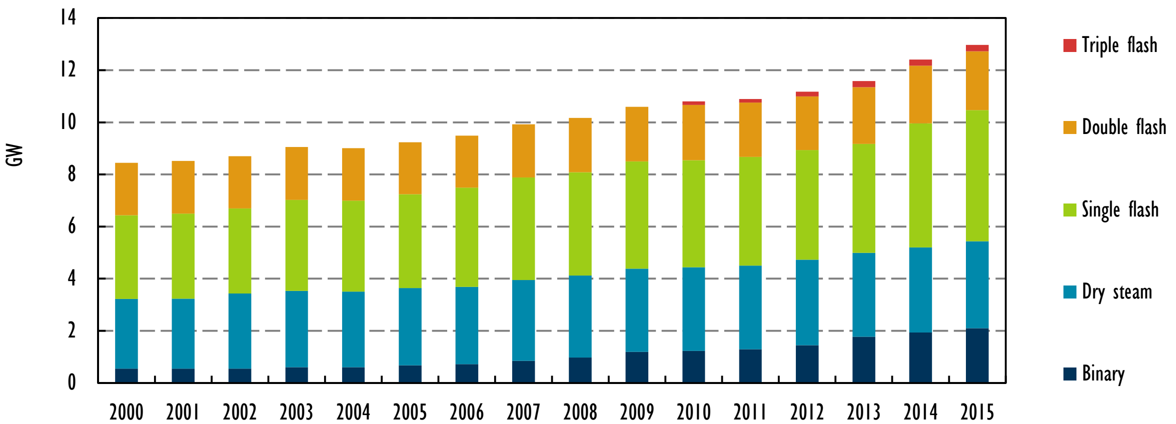
Geothermal

Technology development

Geothermal plants can generate power from three types of resources: high-temperature hydrothermal resources, low and medium-temperature hydrothermal resources, and hot rocks. Around 99% of geothermal plants deployed worldwide use the first two types, using steam turbine technology and binary cycles as power conversion.

Single-flash steam plants are installed where geothermal pools reach temperatures of 180°C and higher. In these high-temperature reservoirs, the liquid water component boils, or “flashes”, as pressure drops. Around 40% of global geothermal capacity installed in 2015 uses flash steam systems. Dry steam plants directly utilise steam from the geothermal pool for powering the turbine. These types of plants are less common and make up to 25% of cumulative geothermal capacity in 2015 (Figure 2.31).

Figure 2.31 Geothermal capacity segmentation per technology (GW)



Note: Plants using back-pressure turbines are included in the single-flash category.

Source: Analysis based on GEA (2016), *Capacity Dataset for the IEA*.

Binary plants provide around 15% of total world capacity and have expanded quickly over the last decade, as they are able to operate on low- to medium-temperature (70°C and as high as 180°C) geothermal pools, which are more geographically widespread than high-temperature ones. Binary plants integrated with organic rankine cycle (ORC) bioenergy technologies for co-generation have received attention in recent years with commissioning of a 4.5 MW plant in Germany (Oberhaching-Laufzorn region) in 2014 and 5 MW in Italy (Tuscany) in July 2015 (Enel Green Power, 2015).

Since 2012, several enhanced geothermal system (EGS) plants have been commissioned. EGS plants generate power from hot rocks by improving their permeability via injecting water at high pressure to fracture the rock where deployment of conventional geothermal plants is uneconomical due to few or no hot underground water resources. As such, EGS technology offers the opportunity to tap enormous geothermal potential globally for sustainable and base-load renewable energy generation. R&D has occurred in Australia, France, Germany, Switzerland and the United States. So far, operational power plants are based in France and Germany. The German experience indicates that facilities that produce both electricity and heat are more viable than electricity-only facilities. The theoretical energy potential from these systems is large; for instance, it is estimated that potential for EGS in the United States alone could be as high as 100 GW over the next 50 years (DOE Geothermal Technology Office, 2016). However, government policy support is still needed to overcome technological and economic challenges in order to tap this potential.

Geothermal investment costs are project- and site-specific. Typical investment costs of high-temperature geothermal electricity range from USD 2 000/kW to USD 5 000/kW, while the investment costs of binary plants range from USD 2 400/kW to USD 5 600/kW. Geothermal plants have one of the highest capacity factors among renewable energy technologies, usually ranging from 60% to over 90% depending on resource availability and the site. However, higher capacity factors up to 95% are also possible in some locations, such as Iceland. Generation costs for geothermal plants usually range from USD 35/MWh to USD 200/MWh, with binary plants generally at the high end of this scale. However, geothermal projects usually have long lead times of five to seven years, from the exploration, drilling and construction phases through to commissioning. High initial investment costs of exploration and drilling and risks associated with them remain an important challenge to the deployment of geothermal power globally.

Geothermal projects in most countries with suitable resources are entitled to renewable policy support measures such as FITs, energy auctions with long-term contracts, green certificates, capital grants and soft loans. However, there are cases where deployment of geothermal energy is targeted directly. For example, the government of Indonesia aims to organise geothermal-only auction rounds to contract 1.5 GW of new projects for commissioning over two years after 2021. International development finance institutions, especially the European Bank for Reconstruction and Development (EBRD), International Finance Corporation (IFC), World Bank, KfW Development Bank and others, play a key role in financing geothermal projects in developing countries.

So far, 31 countries have some geothermal capacity installed, 3 countries pledged specific geothermal targets in their INDCs, and around 20 countries have some form of national geothermal goals. The Global Geothermal Alliance, which was created in 2014 by a coalition of 23 countries and has since grown rapidly to 38 countries, issued a joint statement to the United Nations Framework Convention on Climate Change (UNFCCC) during the 21st Conference of the Parties (COP21) calling for a recognition and roll-out of geothermal energy. The goal of the alliance is to facilitate a fivefold growth in geothermal capacity by 2030, compared with 2014 levels (UNFCCC, 2016b).

Market status and outlook: Main case summary

In 2015, geothermal power generation increased by an estimated 6% to 82 TWh from 2014, while capacity grew by 575 MW to reach 13 GW. **Turkey** led deployment, adding over 200 MW, 37% of all new capacity installed globally from 2014-2015, driven by an attractive FIT, followed by the United States (+70 MW), Mexico (+50 MW), New Zealand (+50 MW) and Iceland (+45 MW). In 2015, new additions were 30% lower versus 2014 mainly due to slower growth in **Kenya**, which commissioned only 20 MW of capacity (compared with 330 MW in 2014). Single-flash steam continued to be a dominant geothermal technology responsible for about a half of all new installations added last year, followed by binary and dry steam plants.

Geothermal generation is expected to grow by 26 TWh to a total of 107 TWh by 2021. Capacity is expected to grow by 3.7 GW over the medium term in line with the *MTRMR 2015* forecast, and reach almost 17 GW by 2021 (Table 2.9). **Indonesia** and the **Philippines** together are expected to lead the deployment, accounting for 36% of new additions globally. Mexico, Turkey and the United States are expected to contribute with smaller additions.

Table 2.9 Geothermal capacity (GW) in selected countries and its contribution to renewable power generation in 2015 and 2021

	Cumulative capacity (GW)		% of renewable generation	
	2015	**2021**	**2015**	**2021**
United States	3.6	3.8	3%	2%
Philippines	2.0	2.4	49%	49%
Indonesia	1.4	2.3	32%	36%
New Zealand	1.0	1.2	22%	26%
Mexico	0.9	1.2	13%	10%
Italy	0.8	0.8	6%	5%
Iceland	0.7	0.8	27%	32%
Turkey	0.6	1.1	4%	6%
Kenya	0.6	1.0	56%	57%
Japan	0.5	0.6	1%	1%
Total	**13.0**	**16.6**	**1%**	**1%**

Sources: Historical data based on IEA (2016d), *Renewables Information 2016*, www.iea.org/statistics; GEA (2016), *Capacity Dataset for the IEA*; Platts (2016), *World Electric Power Plants Database*.

In several countries, geothermal projects deliver high shares of renewable power generation and constitute an important component of their total power generation. Geothermal delivers the highest shares of renewable power production in Kenya, the Philippines, Indonesia, Iceland and New Zealand. In **Kenya**, high geothermal resource availability, growing energy demand, a low electrification rate and the government's focus on the technology's deployment resulted in geothermal plants delivering around 55% of total country's power generation in 2015.

Indonesia's capacity is expected to grow by 880 MW to reach 2.3 GW in 2021. This expansion represents 25% of global geothermal capacity growth over the medium term. Excellent geothermal resource availability in Indonesia will be one of the main drivers for the deployment. It is estimated that Indonesia has 29 GW of geothermal potential, and the country exploited only 4.5% of this potential (ESDM, 2015). In Indonesia, geothermal power generation is supported by a FIT depending on the location of the plant (regional specification) and geothermal pool temperature. As of February 2016, geothermal plants with capacities larger than 10 MW can be fully owned by foreign entities. However, for smaller plants, foreign entities are not able to hold the majority of the ownership (BNEF, 2016a). Additionally, the government aims to further boost geothermal deployment by running technology-specific auctions in 2016 and 2017 to procure an additional 1.5 GW of new geothermal capacity, to be commissioned after 2021 (Indonesia Investments, 2016). However, despite recent policy changes, several administrative and regulatory barriers remain.

The Philippines is expected to add 450 MW of new geothermal capacity over the medium term, reaching a total of 2.4 GW in 2021. Deployment will be driven by energy security needs and growing electricity demand, accompanied by technology-specific targets and large, yet untapped, geothermal potential. **Mexico** is anticipated to add 370 MW of new capacity, reaching a total of 1.2 GW, while **Turkey** is expected to add 470 MW over the medium term, adding to an overall 1.1 GW, driven by the country's FIT, growing power demand and high resource potential.

Concentrating solar thermal power (CSP/STE)

Technology and cost developments

The deployment of CSP plants to generate STE[15] is at a stage of market introduction and expansion, with approximately 4.6 GW cumulative installed capacity worldwide in 2015. Despite being a small market, CSP remains a proven renewable technology that provides flexibility benefits to power grids, especially when integrated with thermal storage. The technology's output can then follow closely the electricity demand profile during the day in regions with high direct normal irradiance ("clear skies") and provide firm peak, intermediate or base-load capacity.

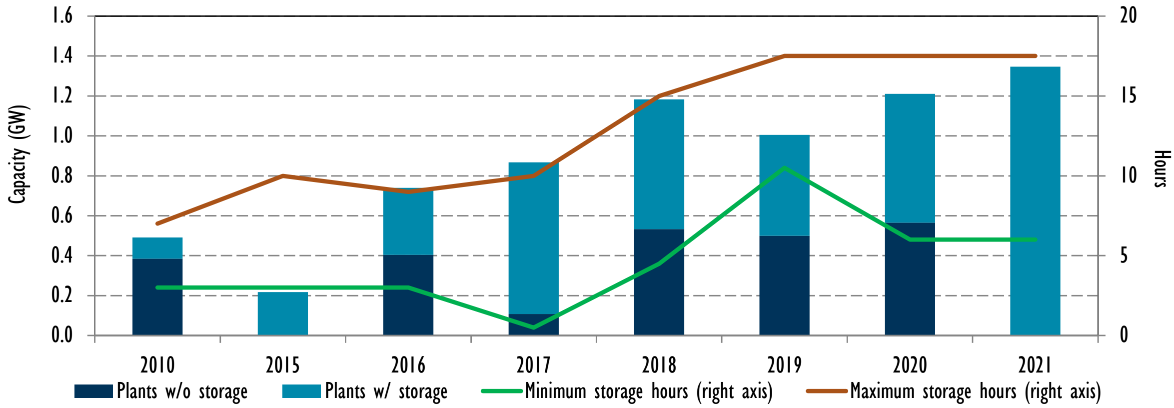
Over the last two years, activity expanded beyond traditional markets in Spain and the United States, where it slowed. Spain remains the global leader in existing capacity (2.3 GW), of which nearly half integrates thermal storage, however developers including Abengoa Solar, ACWA, BrightSource Energy and SolarReserve are turning to countries where the potential for CSP with storage may offer a higher value to meet electricity demand variations, especially in countries with evening peak demand. China could become the next-largest market while Chile, Israel[16], Morocco, South Africa and the United Arab Emirates are emerging thanks to supportive policies.

CSP plants continue to grow in size and scale with increasing thermal storage capacity. Arguably, because of the economies of scale and O&M costs, CSP technology is more cost-efficient if installed as large power plants. While only around 11% of the global projects installed historically are 100 MW or greater, that percentage grew to 39% of total installations from 2013 to 2015 due to the contribution of five large-scale projects deployed in the United States and others in emerging markets. Of the existing 4.6 GW of CSP capacity installed at the end of 2015, roughly 1.4 GW (30%) includes storage. Over the medium term, approximately 78% of all new capacity will incorporate storage (Figure 2.32). CSP with storage can increase the flexibility of an energy system, facilitating the integration of variable renewable technologies such as solar PV and wind.

[15] For further analysis on the CSP sector, please see the IEA *Technology Roadmap: Solar Thermal Electricity,* 2014 edition.

[16] 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 2.32 Annual additions of CSP installed capacity with or without storage and average corresponding battery size (in hours), historical and forecast



Sources: Historical data based on IEA (2016d), Renewables Information 2016, www.iea.org/statistics/; NREL (2015), Concentrating Solar Power Projects; BNEF (2015b), Renewable Energy Projects database.

While once considered a novelty, the use of advanced molten salt storage is now a standard concept. Abengoa Solar's 250 MW Solana parabolic trough plant, installed in the United States in 2013, has six hours of full-load thermal energy storage using molten salt and yields as much annual energy as California's nine Solar Electric Generating Systems that do not use molten salt. SolarReserve operates the 110 MW Crescent Dunes tower that uses molten salts as both heat transfer fluid and a storage medium for ten-hour storage and is planning a 260 MW plant (with 14 hours of storage) utilising similar technology in Chile. In emerging markets, storage remains critical, driven by the need to meet evening peak demand in countries such as South Africa, where regulators approved at least a half-dozen CSP plants with storage. In northern Chile, reliable electricity from CSP can be combined with large-scale PV to deliver base-load power, a requirement for the country's large mining industry.

Although parabolic trough plants with oil as a heat transfer fuel represent the bulk of existing capacity, with or without molten salt thermal storage, the diversification of the CSP technology landscape is notable to date. Although parabolic dish and Fresnel linear promises have not materialised, central receiver systems (CRS – heliostats surrounding towers) are becoming the alternative. Capacities of newly developed parabolic troughs and tower plants draw closer every year, with 46% of added capacity based on parabolic trough technology, and 41% based on tower technology (mainly due to capacity in the United States) as of 2014.

The shift toward tower technology represents the inherent limitations in trough technology. Temperature levels and the high costs associated with relatively low efficiency are challenges that tower technology can potentially overcome. In particular, where there is a need for large storage, the higher working temperature of molten salt towers reduces the volume of storage material by a factor of three. However, a number of risks remain, and some large current projects are exemplary of the technology's low level of maturation to date. For a variety of reasons, both BrightSource's Ivanpah plants (three CRS on one site, no storage) and SolarReserve's Crescent Dunes (one tower, large storage) experienced extensive commissioning periods, and have not yet reached their full capacities.

The total investment costs of CSP plants remain high but have already started to decline. The relatively high up-front investment costs of CSP can make project bankability difficult compared to other renewable technologies. For large plants (>50 MW), investment costs are USD 4 000/kW to USD 9 000/kW, depending on the solar field size, the storage capacity, and labor and land costs. In countries such as Morocco, however, current PPAs signal the resolution of some manufacturers to achieve significantly lower capital expenditures in the coming years. Furthermore, the perception remains that CSP, and its more complex designs, is regarded as an emerging technology, adding the higher financing cost of a demonstration as a factor in LCOE analysis. It is expected that greater standardisation of plant design and equipment as markets mature will drive investment costs down over the medium term.

There are estimates regarding the investment cost of CSP plants, but the uneven nature and technological variety of existing plants makes costs difficult to track and harmonise. Therefore, investment cost data may not fully represent the cost dynamics on a country and project basis as projects can have different technological designs, dispatch profiles, financing and support mechanisms. For example, in the United States, the 110 MW Crescent Dunes tower, with ten hours of storage, was completed in 2015 at an approximate cost of USD 9 100/kW. Likewise, Phase 1 of the Ouarzazate parabolic trough plant in Morocco (NOORoI) at 160 MW was fully commissioned in early 2016 at around USD 8 500/kW with three hours of storage. The investment costs for projects without storage remain significantly lower. The US 250 MW Abengoa Mojave parabolic trough plant, without storage, became operational in 2014 at an approximate cost of USD 5 700/kW, while India's 125 MW Reliance Power Ladkan Fresnel plant, commissioned in 2014 without storage, cost around USD 3 300/kW. In the end, it can be difficult to determine capital costs of a CSP plant as it depends largely on the size of the solar field, which determines the electric output and represents approximately half of the investment cost. Cheaper and more standardised components and improvements in design can all help to reduce costs, as well as innovative developments related to higher working temperatures.

The initial capital investment, which accounts for the bulk of the total capital expenditure, dominates the LCOE of CSP plants and varies widely given variety in location,[17] technology, the quality of the solar resource and design. The LCOE of an existing CSP plant can range anywhere between USD 140/MWh and USD 260/MWh, while public data point to PPAs that can provide other estimations and indirect information relative to LCOEs. For example, the estimated LCOE of Morocco's 160 MW NOORoI parabolic trough plant in Ouarzazate with three hours of storage is based on its PPA of 1 620 Moroccan dirhams (MAD) per MWh (USD 190/MWh). On the other hand, the 200 MW NOORoII trough plant with seven hours of storage secured a PPA at MAD 1 360/MWh (USD 140/MWh), witnessing a lower LCOE. However, the 150 MW NOORoIII tower, with eight hours of storage, will be slightly more costly at MAD 1 420/MWh (USD 150/MWh). In South Africa, a base price bid of ZAR 1 447/MWh (USD 120/MWh at that time) was made for the 100 MW Redstone CSP tower project with 12 hours of storage to be built by ACWA and SolarReserve. However, electricity during five hours of peak demand hours will be remunerated 2.7 times the base price. Cost reductions are expected over the medium term given the number of plants in operation and the pipeline for 2021 through improving

[17] Generation potential of a solar CSP plant is highly determined by direct normal irradiance (DNI), unlike solar PV, which can use diffuse irradiance.

performance and capital cost reductions. Additional reductions can come from the impact of greater R&D investment, reduced risks and the scaling up of plants to create greater operational experience.

Market status and outlook: Main case summary

Overall, CSP forecast is higher than *MTRMR 2015.* China's more optimistic outlook is expected to compensate for project delays in Chile, South Africa and the United States. Global CSP capacity is set to reach 11 GW by 2021, an addition of approximately 6.4 GW over 2015, with the majority of growth expected in emerging markets deploying approximately 95% (6 GW) of all new CSP plants over the medium term. Global generation from CSP is expected to reach close to 30 TWh by 2021, up from around 10 TWh in 2015.

Table 2.10 CSP capacity and forecast by selected countries (GW)

	2014	2015	2016	2017	2018	2019	2020	2021
United States	1.7	1.8	1.8	1.8	1.8	1.8	1.9	2.1
Spain	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
China	0.0	0.0	0.5	0.8	1.4	2.0	2.5	3.1
South Africa	0.0	0.1	0.2	0.3	0.4	0.5	0.6	0.7
Morocco	0.0	0.0	0.2	0.2	0.4	0.5	0.6	0.7
Chile	-	-	-	-	0.2	0.3	0.5	0.6
India	0.2	0.2	0.3	0.4	0.4	0.4	0.4	0.4
United Arab Emirates	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.3
Israel*	-	-	-	0.2	0.2	0.3	0.3	0.3
Egypt	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1
World	**4.4**	**4.6**	**5.4**	**6.2**	**7.4**	**8.4**	**9.6**	**11.0**

Note: Rounding may cause non-zero data to appear as "0.0" or "- 0.0". Actual zero-digit data is denoted as "-".

* 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.

Sources: Historical data based on IEA (2016d), *Renewables Information 2016*, www.iea.org/statistics/; NREL (2015), *Concentrating Solar Power Projects;* and BNEF (2015b), *Renewable Energy Projects* database.

The **United States'** CSP capacity is expected to increase by 350 MW over the medium term due to large investments in R&D from the DOE and despite a potentially large pipeline of projects totalling around 1 GW. While the 110 MW Crescent Dunes project achieved commercial operation in November 2015, other project developments were put on hold amid discussions of the ITC extension, pushing back growth in CSP until later in the medium term and beyond. The forecast in the United States remains uncertain given market and policy setbacks. The 377 MW Ivanpah tower plant in California is slowly ramping up and should reach full capacity in 2018. While still in its planned ramp-up phase, the Crescent Dunes innovative molten salt receiver is performing above design expectations in terms of heat transfer efficiency, availability, ramping and transient conditions.

South Africa entered the CSP market in 2015 with the 100 MW KaXu Solar One STEG plant with three hours of storage. Over the medium term, the country is expected to install an additional 600 MW of CSP, all with storage thanks to the country's excellent solar resources and supportive government policy. The country's REIPPPP is driving cost reduction and innovation with bids for CSP towers while the cost of storage is falling significantly.

In **Morocco,** the government's endorsement of CSP through the Moroccan Agency for Solar Energy encouraged the successful tendering of 510 MW to date. NOORoI, a 160 MW parabolic trough plant with three hours of storage, built at Ouarzazate by ACWA Power, was connected to the grid in February 2016. NOORoII, a 200 MW parabolic trough with seven hours of storage, and NOORoIII, a 150 MW solar tower with eight hours of storage, are under construction. Both are expected to be commissioned in 2017. Overall, Morocco's CSP capacity is expected to expand by 660 MW over the medium term. The Moroccan Institute for Research on Solar Energy and New Energy continues to support CSP deployment in Morocco through a wide variety of R&D projects.

China is making moves in the CSP market despite its low installed capacity to date, with nearly 3.1 GW expected in the medium term, and most of the projects over 100 MW including several hours of storage. With national average wind and solar curtailment rates above 10%, CSP plants with large storage capacity could facilitate the integration of variable renewables. Alongside the country's target of 10 GW of CSP by the end of 2020, the government also announced in May 2016 that it will formally introduce a FIT of around USD 180/MWh. However, the details of this policy were missing at the time of writing.

Chile's CSP capacity is expected to reach 615 MW by 2021, driven heavily by the advantage that storage provides to base-load energy supplies for the mining operations in the north of the country. However, the country's forecast is less optimistic versus *MTRMR 2015* as some projects are expected to face delays, especially those owned by Abengoa, which filed for bankruptcy in November 2015.

Storage will be an attractive component driving CSP in Chile as planned projects average over 12 hours. Despite the financial woes of the Spanish investor company, Abengoa, the 110 MW Cerro Dominador STEG plant, due to be commissioned in 2019, is set to incorporate 17.5 hours of storage (the largest to date). Recognising the benefits of storage for the country and its benefits over solar PV, developers in Chile are considering hybrid setups combining different technologies and fuels. SolarReserve's 260 MW Copiapo plant with 14 hours of storage (expected to be commissioned in 2019) will combine CSP and solar PV to provide round-the-clock power for the mining industry. And on cloudy days, the plant could use fossil fuel in a relatively small amount to heat the salt (Solar Reserve, n.d.), which still results in a dramatic reduction in fuel use, but allows the system's steam turbine to run at full capacity.

Market outlook: Accelerated case summary

The additional growth for CSP in an accelerated case is limited over the medium term due to policy uncertainties, long project lead times and increasing competition with solar PV that puts pressure on CSP installation rates. Still, some markets could result in higher-than-expected deployment given enhanced policy drivers, cost reductions and overcoming challenges related to permitting and grid upgrades such as in the United States, Chile, Israel, Morocco, South Africa and China. The expansion of CSP into emerging markets is expected to continue, but the pace of growth will depend on improvements in national policies and market frameworks remunerating ancillary services and capacity benefits of the CSP technology. In addition, further progress toward mitigating early-stage development hurdles and lowering hardware costs are also required to achieve faster deployment. In all, global cumulative CSP capacity could be over 4 GW higher under this report's accelerated case.

Ocean

Technology development

Ocean power accounts for the smallest portion of renewable electricity globally, and the majority of projects remain at demonstration phase. However, with large, well-distributed resource potential and the deployment of larger pilot projects, ocean energy has a potential to scale up over the long term.

Ocean energy refers to technologies that generate power from the natural conditions of ocean and sea waters. So far, there are five main categories of ocean technology for power generation: tidal range, ocean and tidal currents, wave power, temperature gradients, and salinity gradients. Technologies to harness ocean power are not yet mature in comparison with mainstream renewable technologies. However, tidal and wave projects have been under development since the 1970s. Currently, tidal barrages are the most developed marine technology. The largest tidal barrage projects are operating in France and Korea. The French project has a capacity of 240 MW and the Korean one 254 MW, and they constitute the majority of deployed ocean capacity as of 2015.

Since ocean technology is still in the demonstration phase, high investment and O&M costs remain barriers to scaling up its deployment. In 2015, the Technology Collaboration Programme on Ocean Energy Systems conducted a study investigating possible cost reductions provided ocean technology leaves the demonstration phase and enters into commercial development. Currently, the average investment costs for 3 MW wave power plants oscillate around USD 18 100/kW; nevertheless, costs could be decreased by half to USD 9 100/kW for a 75 MW plant. Investment costs for tidal projects of 10 MW are around USD 14 600/kW, but could decrease to USD 5 600/kW for larger projects up 90 MW. For ocean thermal energy conversion, plant costs are higher and could reach to USD 45 000/kW. However, some studies indicate that costs could be significantly lower, around USD 13 000/kW, for 100 MW plants (OES TCP, 2015).

Market status and outlook

In 2015, ocean power generation increased slightly by just over 40 GWh, reaching a total of 1 TWh, while capacity stood at 537 MW globally. In 2015, only 13 countries had some type of ocean capacity installed (tidal range, tidal stream and wave). Of these, only two installed projects with a capacity larger than 200 MW: Korea (254 MW) and France (240 MW).

Over the medium term, ocean capacity should increase by an estimated 100 MW, reaching 640 MW overall, which is a downward revision in comparison with *MTRMR 2015* projections, mostly due to the stalling of project deployments in Korea and uncertainty of the next CfD allocation run to be held in the United Kingdom (Table 2.11).

In **Korea**, the Mid-Term and Long-Term Clean Ocean Energy Development Plan 2015-2025 was released in late 2015 to stimulate ocean energy development and increase the country's competitiveness in the sector. Additionally, the plan provides a strategy for ocean energy to scale up in the country. The initial target for marine power to deliver 2.4% of Korea's electricity demand was decreased to 1.6%, as the deployment has been slower than expected due to stronger environmental restrictions and the reluctance of local populations (Brito e Melo, 2015) in comparison with other renewable technologies.

Marine power is included in Korea's RPS and Renewable Energy Certificate trading schemes. In early 2016, a demonstration project of a 500 kW wave energy plant in Jeju entered a test phase. Korea has plans to develop large tidal projects near Inchon (200 MW), Shinan (260 MW) and Daebang (100 MW) however projects are at an early stage of feasibility study, and uncertainty remains over their date of commissioning (BNEF, 2016c).

In **France**, two tidal stream turbines rated 1 MW each were installed in Paimpol-Brehat (Brittany) in 2016 and will be connected to the grid later this year. In June 2015, a tidal energy turbine was successfully installed in Fromveur Passage (Brittany) with 0.5 MW capacity delivering electricity to the nearby island of Ouessant as of November 2015. Additionally, at least two tidal projects of around 22 MW total capacity will be developed in Raz Blanchard (Normandy). Turbine installation is scheduled for 2017, delivering power in 2018. The projects received a PPA contract in 2014 through a Request of Interest.
Overall, the French government sees good potential for ocean technology development, tidal stream in particular, and will continue efforts to expand current capacity levels (Developpement Durable, 2016). New ocean projects will be procured in the next tenders, the earliest to take place in 2016.

In the **United Kingdom**, the Renewable Obligation scheme will close to new applications as of March 2017, and it was announced at the beginning of 2016 that there should be three CfD allocation rounds until 2020 in which marine projects will be able to participate. However, the CfD auction timeline and details are still to be clarified, and it is difficult to assess how marine projects will perform. Postponement of the CfD auctions or lack of contract allocation for marine projects could potentially undermine financial stability of ocean companies in the United Kingdom and result in project cancellation.

In 2015, Atlantis commenced construction of the first phase of the multi-tidal stream array MeyGen project situated in Scotland. The demonstration phase of the project, consisting of four turbines of 1.5 MW capacity each, is scheduled to be commissioned and operational by the end of 2016. The total capacity of the MeyGen project should be further expanded to a total 398 MW of capacity in early 2020s.

In **Canada**, there are projects under development in Nova Scotia that aim to qualify for local FIT support. If the results of the initial projects are promising, the government might run an auction for new ocean capacity procurement in 2020.

Table 2.11 Ocean capacity in selected countries and forecast by region (GW)

Capacity (GW)	2014	2015	2016	2017	2018	2019	2020	2021
Korea	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
France	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3
Canada	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
United Kingdom	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
China	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
United States	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Portugal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
World	**0.5**	**0.5**	**0.6**	**0.6**	**0.6**	**0.6**	**0.6**	**0.6**

Note: Rounding may cause non-zero data to appear as "0.0" or "- 0.0". Actual zero-digit data is denoted as "-".

Sources: Historical data based on IEA (2016d), *Renewables Information 2016*, www.iea.org/statistics; IRENA (2016b), *Renewable Capacity Statistics 2016*.

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3. RENEWABLE TRANSPORT

Highlights

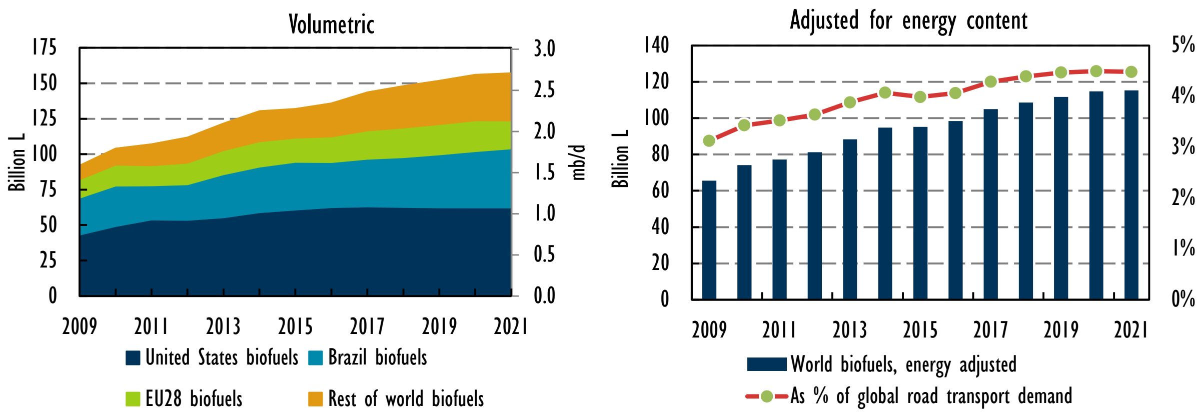
- Global conventional biofuels production increased slightly to 132 billion litres (L) in 2015. However, this represents an increase of just over 1% year-on-year (y-o-y), compared with an average annual growth rate of 6% over 2009-15. Higher mandated requirements in key markets are expected to result in average annual growth of 3% over 2015-21 to reach 157 billion L of production by 2021, an upward revision from the *Medium-Term Renewable Energy Market Report (MTRMR) 2015*. While the global ethanol market is larger than for biodiesel, the total increase in global conventional biofuel production over 2015-21 should comprise a higher share of biodiesel due to strengthened policy support in the United States, Indonesia and Brazil.
- Mandates proved effective in shielding biofuels from the low oil price environment, although this has posed challenges in certain markets. Mandates and supportive biofuel policies have been strengthened in key countries since the downturn in oil prices. Consequently, medium-term production growth is forecast regardless of the duration of low oil prices. However, some market-specific impacts are observed, including a more challenging investment climate and limited opportunities for discretionary blending above mandated volumes. Furthermore, less favourable blending economics provide a greater incentive to minimise blend shares, highlighting the value of suitable governance arrangements to ensure compliance with mandated consumption.
- Asia is poised to head medium-term biofuels market expansion. While the United States and Brazil will comfortably remain the largest biofuel producers in 2021, Asian markets are forecast to account for over a third of the 2015-21 global biofuels production increase. Driven by considerations regarding security of supply, enhanced policy support for the consumption of domestically produced biofuels is boosting Asian markets for ethanol (e.g. in Thailand and India) and biodiesel (e.g. in Indonesia and Malaysia). In the 28 member states of the European Union (EU28), it remains too early to conclude if the challenging 2020 target of 10% (by energy) of transport fuels from renewable sources will be met. Biofuels compliant with mandatory sustainability criteria accounted for 75% of EU28 transport sector renewable energy consumption in 2014. However, biofuels sustainability remains a crucial consideration in rapidly growing markets where strong governance frameworks are yet to be established.
- Advanced biofuel market development continued in 2015 with a number of new plants coming on line in different geographic locations, and several more are anticipated to start construction in 2016. Furthermore, new projects were still announced despite the challenging investment climate caused by low oil prices. These include potentially lower-cost replication projects, even as the pioneering first commercial-scale facilities are working to scale up production towards rated capacities. The *MTRMR 2016* forecasts between 1 billion L and 2.5 billion L of advanced biofuel production by 2021, equating to a share between 0.6% and 1.5% of total biofuel production. This highlights that more widespread policy support is essential to accelerate growth so that advanced biofuels make a larger contribution to transport sector decarbonisation.
- Biofuels are essential to the aviation industry's decarbonisation plans. Several aviation biofuel production processes are already certified for use, and a growing number of commercial flights and fuel off-take agreements demonstrate sustainable jet fuel demand. However, regional supply chain development and actions to reduce cost premiums over conventional jet fuels are needed.

Conventional biofuels global overview

Global biofuels production increases slightly despite a contraction in biodiesel output

In 2015, biofuels production equated to around 3% of all transport fuel demand and 4% of world road transport fuel demand. These shares are expected to rise slowly, reaching around 3.7% of all transport fuel and 4.5% of road transport fuel demand in 2021.[1] Production volumes increased by just over 1% y-o-y to reach 132 billion L in 2015, slightly lower than the 134 billion L anticipated in the *MTRMR 2015* and lower than the average annual growth rate of 6% during 2009-15. Despite the current low oil price environment, the potential curbing effects of the "blend wall"[2] in the United States and an uncertain long-term policy framework in the European Union (EU), blending mandate increases in a number of countries mean world biofuels production is still forecast to rise in the medium term to around 157 billion L by 2021 at an annual average growth rate of just under 3%, an upward revision from the *MTRMR 2015*.

Figure 3.1 World conventional biofuel production, (2009-21)



Note: mb/d = million barrels per day.

Sources: IEA (2016a), *Oil Information* (database), www.iea.org/statistics/; IEA (2016b), *Monthly Oil Data Service (MODS) [May 2016]*, www.iea.org/statistics/; MAPA (2016), *Ministério da Agricultura – Agroenergia;* US EIA (2016a), *Petroleum & Other Liquids*.

World ethanol production in 2015 increased 4% y-o-y and passed 100 billion L for the first time to reach just under 101 billion L. Output is forecast to reach almost 112 billion L by 2021, an upward revision on the *MTRMR 2015* forecast. Growth is driven by expanding markets in India and Southeast Asia, complemented by higher production in Brazil. US ethanol production is forecast to stabilise over the medium term. However, it will remain the largest ethanol producer in 2021.

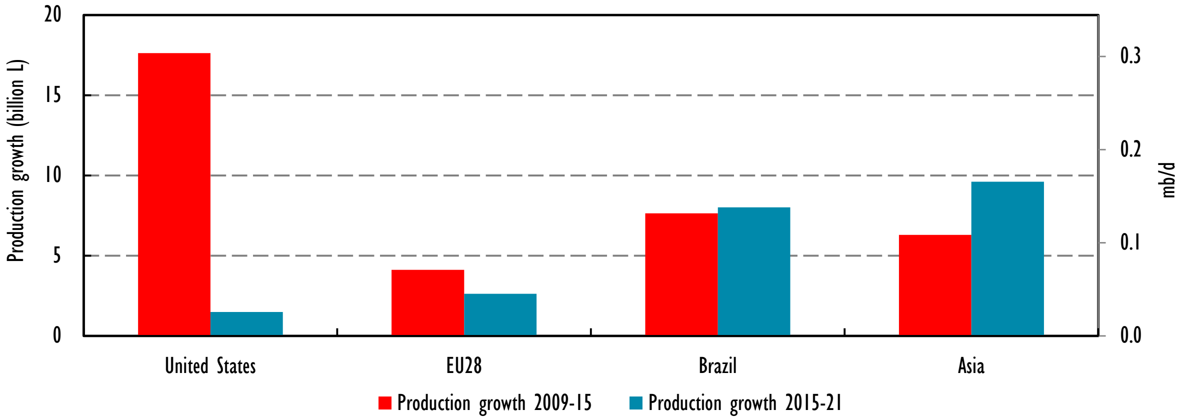
World biodiesel production contracted by 7% with just over 31 billion L of output in 2015. The majority of the downturn is accounted for by the transition between different policy support measures in Indonesia and Germany. However, production is expected to rebound to 2014 levels over 2016 and grow strongly until 2021 at an annual average growth rate of 6.5%, reaching about 45 billion L by 2021. While the global biodiesel market is smaller than for ethanol, the medium-term

[1] Percentage shares of biofuels in road transport fuel are determined on an energy basis. All transport fuels refers to road, marine and aviation fuel consumption.

[2] The "blend wall" refers to the challenge of increasing biofuel consumption in the United States considering the current size of the flexible-fuel vehicle fleet and absence of widespread fuel distribution infrastructure for biofuel blends higher than E10 (gasoline with 10% ethanol by volume).

expansion in production is anticipated to be larger with increased output driven by higher mandated demand in the United States, Brazil and some Association of Southeast Asian Nations (ASEAN) countries, notably Indonesia.

Figure 3.2 Conventional biofuel production growth comparison, (2009-15 and 2015-21), selected countries and regions



Note: *Asia* refers to the Asia and Pacific region with the addition of the People's Republic of China (hereafter "China") but does not include Australia and New Zealand.

Sources: IEA (2016a), *Oil Information* (database), www.iea.org/statistics/; IEA (2016b), *Monthly Oil Data Service (MODS) [May 2016]*, www.iea.org/statistics/; MAPA (2016), *Ministério da Agricultura – Agroenergia;* US EIA (2016a), *Petroleum & Other Liquids*.

In 2015, the transport sector accounted for 23% of global energy-related carbon dioxide (CO_2) emissions and remains the least diversified end-use sector with 93% dependence on oil (IEA, 2016c). Therefore, limiting global temperature rise to well below 2°C as per the United Nations 21st Conference of the Parties (COP21) global climate agreement will require significant decarbonisation of the sector. Biofuels make a key contribution within the International Energy Agency (IEA) long-term 2 Degree Scenario (2DS),[3] especially within non-urban transport where opportunities for electrification are more challenging.

From reviewing intended nationally determined contributions (INDC) submissions ahead of COP21, biofuels are specifically mentioned by several key producer countries:

- Argentina: substitution of fossil fuels by biofuels
- Brazil: increasing the share of sustainable[4] biofuels in the energy mix to approximately 18% by 2030 (specific mention of ethanol and biodiesel) and an increasing share of advanced biofuels
- China: the promotion of new types of alternative fuels

  India: aspirational target of 20% blending of biofuels, both for biodiesel and ethanol, as well as mention of a 5% biodiesel blends in railways and defence.

Of the INDCs submitted ahead of COP21, more than 60 recognised biofuels-supportive policies by including them in their carbon emission reduction plans (GRFA, 2016). However, there is no mention of biofuels by the European Union, Indonesia or the United States.[5]

[3] The 2DS lays out an energy system deployment pathway and an emissions trajectory consistent with at least a 50% chance of limiting the average global temperature increase to 2°C.

[4] Requirements for determining sustainability are undefined within the document.

[5] All INDC information provided in this paragraph sourced from country INDC submissions (UNFCCC, 2016).

In addition, the global Below50 collaboration initiative from the World Business Council for Sustainable Development, in partnership with Sustainable Energy for All (SE4All) and the Roundtable on Sustainable Biofuels, has been established to work with the biofuels industry to promote sustainable fuels that are a minimum of 50% less carbon-intensive than conventional fossil fuels. The purpose of the collaboration is to accelerate growth in the global market for sustainable fuels via scaling up their development and increasing the number of companies using biofuels that meet the aforementioned criteria. Furthermore, the activities of organisations such as the Global Renewable Fuels Alliance, a federation that represents renewable fuel producers from around 45 different countries, also advocate biofuels to deliver climate change mitigation as well as their potential to provide security of supply benefits for net-oil-importing developing countries.

Table 3.1 World conventional biofuels production, (2015-21)

Billion L	2015	2016	2017	2018	2019	2020	2021	CAAGR
North America	62.9	65.0	65.5	65.0	64.7	64.7	64.7	0.5%
United States	60.8	62.5	63.1	62.7	62.4	62.3	62.3	0.4%
Latin America	39.0	37.5	40.6	42.3	44.6	47.0	49.0	3.9%
Brazil	33.6	31.8	33.6	35.1	37.4	39.7	41.7	3.6%
EU28	17.0	18.1	20.0	20.9	21.3	21.8	19.7	2.4%
Asia and Pacific	8.6	10.2	12.1	13.9	14.9	16.1	17.1	12.1%
ASEAN	6.6	7.9	9.5	10.9	11.6	12.5	13.2	12.2%
India	0.8	1.2	1.4	1.7	1.9	2.2	2.5	19.7%
China	3.2	3.8	3.9	4.1	4.2	4.3	4.6	6.0%
Rest of world	1.2	1.4	1.7	1.9	2.1	2.2	2.2	10.0%
Total world	**132.0**	**135.9**	**143.7**	**148.1**	**151.9**	**156.1**	**157.2**	**2.9%**

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

Sources: IEA (2016a), *Oil Information* (database), www.iea.org/statistics/; IEA (2016b), *Monthly Oil Data Service (MODS) [May 2016]*, www.iea.org/statistics/; MAPA (2016), *Ministério da Agricultura – Agroenergia;* US EIA (2016a), *Petroleum & Other Liquids*.

Biofuels production in 2016 is expected to be constrained within some countries due to the potentially disruptive impact on crops and harvest conditions from temperature and precipitation changes as a result of the strong 2015-16 El Niño weather event. The effects from this may be most evident on palm oil production in Southeast Asia. Global soybean production is anticipated to be affected to a lesser degree, with a good harvest in Brazil and generally favourable conditions in the United States and Argentina.

While the *MTRMR* forecast is for biofuels production, the important role fiscal incentives play in increasing biofuels competitiveness at the pump, and therefore consumption, should also be noted. This is evidenced by examples such as the surge in hydrous ethanol consumption in Brazil during 2015 after tax increases on gasoline, steady growth of favourably taxed E10[6] demand in France, and uptake of subsidised E20 and E85 ethanol blends in Thailand.

[6] E10 equates to a blend of 10% ethanol by volume with gasoline, similarly subsequent references to E15, E20 and E85 within the chapter refer to the volume share of ethanol blended with gasoline.

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

Country	Ethanol	Biodiesel	Advanced biofuels	Carbon intensity (CI) reduction policy	Selected policy description(s)
United States	68.5 billion L of renewable fuels in 2016 and 136 billion L by 2022		Yes, within Renewable Fuel Standard (RFS2)	Low Carbon Fuel Standard (LCFS) in California.	Biodiesel blenders' tax credit extended until the end of 2016. LCFS readopted in September 2015.
Canada	5%	2%	-	In British Columbia	Values shown are for federal mandates; provincial requirements vary.
European Union	10% renewable energy in transport by 2020 (T)*		Double counted in 2020 target	Greenhouse gas (GHG) intensity of fuels to reduce 6% by 2020	Non-binding national sub-targets for advanced biofuels (0.5% reference) proposed to member states.
France	7%*	7.7%*	From 2018	-	Advanced biofuel targets for 2018 and 2023 established.
Germany	-	-	Included within Climate Protection Quota (CPQ)	CPQ	CPQ to increase to 4% over 2017-19 and 6% in 2020.
Italy	5%*	5%*	From 2018	-	First European targets for advanced biofuels established.
China	10%	-	-	-	Mandate applies in certain provinces only.
India	5%/10% (T)	-	-	-	Excise duty exemption for fuel ethanol blended with gasoline.
Indonesia	20%	3%	-	-	B20[7] blend mandate in transport is a global high.
Malaysia	-	7%	-	-	Introduction of a B10 mandate under consideration.
Thailand	24% by 2026 (T)	7%	-	-	E20 and E85 blends subsidised.
Argentina	12%	10%	-	-	Ethanol mandate increased in early 2016.
Brazil	27%	7%	-	-	Staged increase in biodiesel mandate over 2017-19.

Notes: Dark green indicates policy changes since *MTRMR 2015*. Light green colour indicates no recent policy changes. Values are mandates unless "T" specified to indicate target. Percentage values are by volume except where a "*" is shown to indicate by energy.

[7] B20 equates to 20% biodiesel by volume blended with fossil diesel, similarly subsequent references to B7, B10 and B15 within the chapter refer to the volume share of biodiesel blended with fossil diesel.

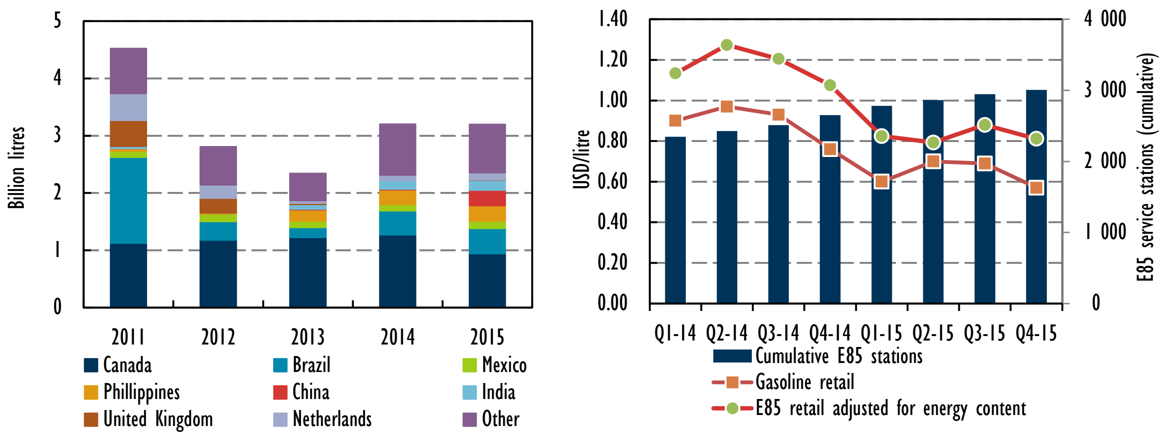
Conventional biofuels regional outlook

Biodiesel comes to the fore in leading United States and Brazilian biofuel markets

In **the United States**, the largest global producer of fuel ethanol, lower motor gasoline prices in 2015 contributed to an increase in demand by around 2.7% y-o-y (US EIA, 2016b) and consequently resulted in a higher volume of ethanol blended, with fuel ethanol accounting for approximately 10% of the total volume of motor gasoline consumption (US EIA, 2016c). Aided by a strong corn harvest, which maintained low feedstock prices, ethanol production rose to 56 billion L and should stabilise at near this level over 2016 before slightly decreasing to 55 billion L in 2021, associated with improved vehicle fleet efficiency of around 2% per year (IEA, 2016d).

It is not anticipated that reduced gasoline consumption will be counteracted by significant increases in the market penetration of E15 and E85 ethanol blends over the medium term. Furthermore, uncertainty remains regarding the path the US Environmental Protection Agency (US EPA) will take with the annual volume standards within the RFS2 scheme until 2022.[8] As a result, prospects for significantly increased domestic consumption over the medium term may be constrained and the industry could focus on increasing exports as a means of delivering ethanol production growth; China, India and the Philippines may hold potential for increased imports.

Figure 3.3 US ethanol exports, 2011-15 (left), and E85 blend market overview (right)



Sources: US EIA (2016d), *Exports by Destination* (database), www.eia.gov/dnav/pet/PET_MOVE_EXPC_A_EPOOXE_EEX_MBBL_M.htm; IEA (2016e), *IEA Energy Prices and Taxes*, *[quarter two 2016]* (database), www.iea.org/statistics/; US DOE (2016a), *Alternative Fuels Data Center – Alternative Fuel Price Report*, www.afdc.energy.gov/fuels/prices.html; US DOE (2016b), *Alternative Fuels Data Center – Alternative Fueling Station Locator*, www.afdc.energy.gov/locator/stations/.

Increased consumption of E15 over the medium term should be more attainable than E85 due to the fact that light-duty vehicles manufactured from 2001 onwards are approved by the US EPA to use E15 blends.[9] Estimates of the current US vehicle fleet that can safely utilise E15 vary and currently sit in the 14-20% range. However, E15 compatibility is on an upward trend, with around 60% of 2015

[8] The US EPA final RFS2 annual volume requirement allocations for 2016 and proposed for 2017 represent reductions on statutory levels previously established, but still allow for continued growth in renewable fuel production.

[9] It should be noted that vehicle manufacturers also have to approve the use of E15 in their vehicles in order to provide consumers with the necessary confidence to use the blend without invalidating vehicle warranties.

model vehicles sold in the United States having manufacturer approval for its use (Reuters, 2016). As such, the key to unlocking market growth potential rests with scaling up fuel distribution infrastructure for the blend. Only a small percentage of the nation's service stations offer blends higher than E10, and the most prominent availability is closely aligned with areas of ethanol production in the Midwestern states. Increased uptake will also require greater consumer awareness, further vehicle manufacturer approvals for E15 use and price competitiveness with E10.

Supported by a good soybean harvest, 2015 biodiesel production in the United States was steady y-o-y at around 4.8 billion L. Output may have been subdued by the announcement of the retroactive application of the USD 1/gallon blenders' tax credit not arriving until December 2015. The medium-term outlook for production is positive, as biodiesel qualifies for the biomass-based diesel, advanced biofuel and total renewable fuel categories of the RFS2. In addition, the establishment of annually increasing RFS2 volume requirements for biomass-based diesel up until 2017 (with a proposed 2018 value also announced) provides demand certainty for the first half of the medium term. Furthermore, the extension of the USD 1/gallon blenders' tax credit over calendar year 2016 should support profitability for producers during the year. As a result of this favourable policy environment, biodiesel production is anticipated to be robust and revised up to just over 7 billion L in 2021, representing an average annual growth rate of 7%. However, it should be noted that demand growth may outstrip production in the short term due to the presence of accumulated stocks.

Demand created by the RFS2 raises the potential for increased biodiesel imports over 2016-17, with countries such as Argentina and Indonesia, as well as global producers of hydrotreated vegetable oil (HVO) fuels, potential suppliers. Forecast production and trade prospects would shift if the aforementioned blenders' tax credit is altered to a producer's tax credit moving forward, as this would provide an economic advantage to domestically produced biodiesel over imports. Such a change was subject to lobbying prior to the announcement of the extension of the blenders' tax credit, and while not implemented, may potentially occur during the medium term; should this happen, production in the United States would likely rise above forecast levels in the *MTRMR 2016*.

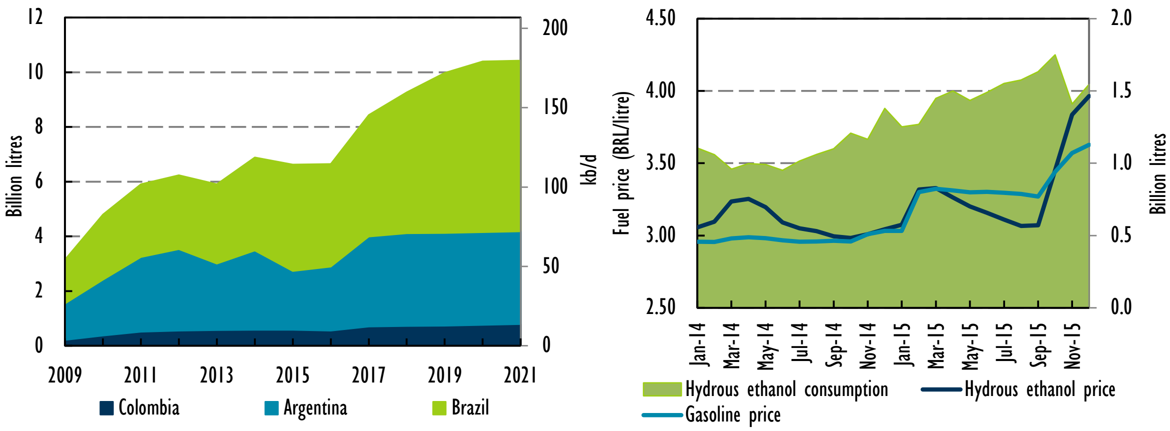
Ethanol production in **Brazil** had a strong year with a record output of just under 30 billion L, representing a y-o-y increase of 3.6%. This was achieved due to a combination of a good sugar cane crop and optimal harvest conditions. As shown by Figure 3.4 a significant y-o-y rise in hydrous ethanol consumption of around 37% (UNICA, 2016) occurred with higher demand as a result of increased competitiveness at the pump due to federal tax increases for gasoline.[10] However, an increase in blended anhydrous ethanol consumption in 2015 due to the higher 27% mandate did not materialise due to a contraction in gasoline consumption related to the current economic downturn. This should result in slower gasoline demand growth of around 1% moving forward, as opposed to 4% per year previously (IEA, 2016d). An increased cane crush can be anticipated for 2016, due to an early start to the harvest and the availability of excess sugar cane from 2015. However, 2016 may see a slight reduction in ethanol production, as the rebound in international sugar prices is expected to encourage a higher share of sugar production at the expense of the fuel.

[10] Federal taxes: Contribution for Intervention in Economic Domain, Contribution to the Social Integration Programme and Contribution for Financing Social Security; more favourable state level taxation developments for ethanol comparative to gasoline are also evident in certain states.

Brazil's INDC stated that the share of biofuels in the energy mix will be maximised through stimulating biofuel supply and consumption. Therefore the central role of biofuels within Brazil's decarbonisation initiatives should see ethanol production increase over the medium term at an average annual growth rate of 3% to around 35.5 billion L in 2021, an upward revision on the *MTRMR 2015*. The potential for growth in the Brazilian ethanol market remains significant. In 2015, ethanol and flex-fuel vehicles accounted for around 70% of the total light vehicle fleet, and 95% of new vehicle registrations during the year were for flex-fuel vehicles. In addition, potential exists for production increases via productivity gains to maximise fuel output from a given crop area and also innovation through the use of specific energy cane varieties.

Forecast 2021 production levels within the *MTRMR 2016* outlook should be technically attainable with existing production capacity, although this would require high utilisation rates; as such, the fragile economic state of the sugar industry places a downside risk on the forecast. Investment in new plants has been on a downward trend since 2010, with limited signs of this being reversed despite some producers announcing proposals for investment in new and expanded production capacity in the wake of strong demand for hydrous ethanol in 2015. In 2015, the number of industry players seeking bankruptcy protection increased, with data from the National Petroleum Agency (ANP) indicating that the number of operating ethanol production plants dropped by 16 y-o-y (F.O. Lichts, 2016a), with ethanol-only plants potentially more vulnerable than producers with well-diversified products.

Figure 3.4 Selected Latin American countries biodiesel production, (2009-21) (left), and hydrous ethanol and gasoline retail prices compared with hydrous ethanol consumption in Brazil, (2014-15) (right)



Note: BRL = Brazilian real; kb/d = thousand barrels per day.

Sources: IEA (2016a), *Oil Information* (database), www.iea.org/statistics/; IEA (2016b), *Monthly Oil Data Service (MODS) [May 2016]*, www.iea.org/statistics/; MAPA (2016), *Ministério da Agricultura – Agroenergia;* F.O. Lichts (2016b), *F.O. Lichts Interactive Data* (database), www.agra-net.com/agra/world-ethanol-and-biofuels-report/ (subscription service); UNICA (2016), *Unica Data* (database), www.unicadata.com.br/historico-de-consumo-de-combustiveis.php?idMn=11&tipoHistorico=10.

Biodiesel production in Brazil increased to 3.9 billion L in 2015, with production prospects improved due to an increase in the biodiesel blending mandate to 7% (B7). The *MTRMR 2016* forecasts production to increase strongly to over 6 billion L by 2021 as a result of a staged increase in the blending mandate from the current 7% to 8% in March 2017, and then increasing by one percentage point annually until reaching 10% in 2019. In addition, the National Council of Energy Policy has already authorised the sale and voluntary use of higher biodiesel blends of between 20-30% depending on their end use[11] (Biofuels International, 2015a). The combined impact of these moves should reduce current biodiesel plant overcapacity, although growth in short-term production may be slightly lower than demand due to existing biodiesel stocks.

Diesel vehicles account for only a small share of Brazil's light-duty vehicle fleet – since 2005, sales of diesel passenger cars have been less than 1% of total sales (ICCT, 2015) – with diesel consumption most prevalent within the heavy-duty vehicle market segment, e.g. buses and road freight. As a result, diesel demand is closely linked to economic activity, and the downturn in the Brazilian economy will dampen demand growth over the beginning of the medium term. Lower diesel demand tempers biodiesel volumes required to meet mandate requirements. Diesel consumption decreased around 6% y-o-y in 2015 (F.O. Lichts, 2016c) and it is reported that biodiesel production in the first quarter of 2016 decreased y-o-y by around 5.5% (F.O. Lichts, 2016d). However, diesel demand is anticipated to return to near 2015 levels by 2021, which combined with the aforementioned mandate increases should result in higher medium-term biodiesel production.

In **Argentina**, biodiesel production, principally from soybean oil, dipped to 2.2 billion L in 2015. However, over the medium term a rebound in production to around 3.4 billion L can be anticipated, underpinned by improved export opportunities. With a number of Argentinian plants eligible to qualify for the Renewable Identification Numbers (RINs) used to demonstrate compliance under the RFS2 programme, increased demand for biodiesel in the United States provides good export prospects. Furthermore, in early 2016 the World Trade Organization (WTO) ruled in Argentina's favour with regard to several claims against EU anti-dumping duties on Argentinian biodiesel imports, although it remains too early to anticipate the eventual outcome of the dispute and timescales should the anti-dumping duties be removed. However, a definitive ruling in Argentina's favour would provide further upside potential for production, as without the duties it is anticipated Argentinian soy oil methyl ester would be competitive with European Union-produced biodiesel. Production could rise above the *MTRMR 2016* forecast should there be an increase in the current 10% blending mandate and via discretionary blending opportunities opened up by higher crude oil prices over the medium term.

Meanwhile, fuel ethanol production in Argentina increased to around 800 million L in 2015, and the *MTRMR 2016* anticipates production rising to around 1 billion L as a result of the increase in the mandate from 10% to 12% in early 2016. The increased requirement is exclusively targeted at production from sugar cane, which should result in equal production compared with output from corn-based plants. The forecast does not include upside potential for ethanol production associated with a possible further mandate increase and changes in agricultural policies that could see increased corn production and facilitate the scale-up of existing corn-based ethanol capacity.

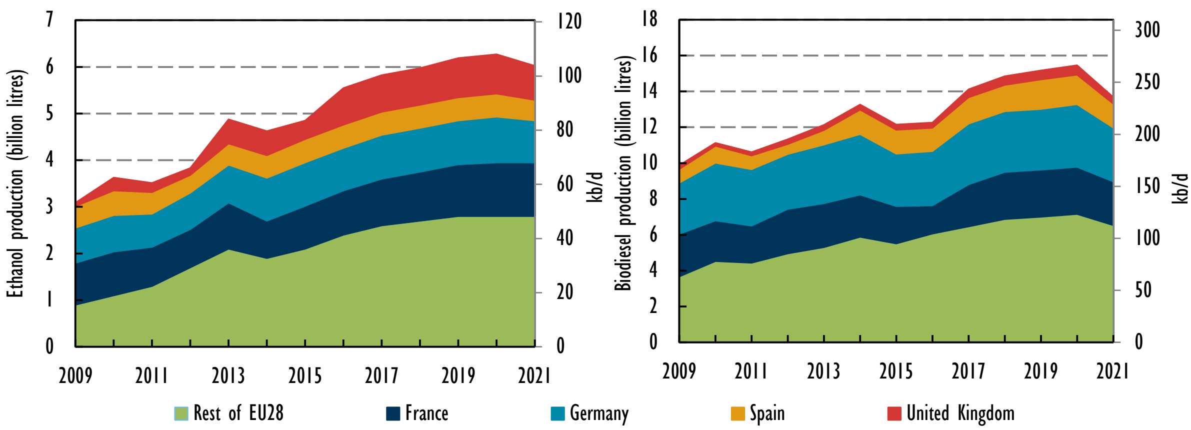
Medium-term ethanol production is also forecast to increase due to the establishment of a 5.8% ethanol blend programme in **Mexico**, an increase in the national blend rate from 5% to 10% in **Ecuador**, and the introduction of national coverage and availability requirements for E85 distribution

[11] End uses being 20% for captive fleets and public pumps, and 30% for transport, agricultural and industrial users.

in **Paraguay**. While in **Colombia**, new ethanol production plants coming on line may facilitate an increase in nationwide blending to 10%.

It remains too early to conclude if the **EU28** 2020 target of 10% of transport fuels (by energy) from renewable sources will be met. However, it is anticipated that meeting the target will be challenging. The latest official figures from the European Commission (EC) for 2014 indicate that a 5.9% share was achieved across the EU28.[12] The *MTRMR 2016* forecast anticipates increases in the utilisation rates for existing ethanol and biodiesel plants moving forward (Figure 3.5), associated with national initiatives to meet individual country targets. Currently, EU28 member states are assessing options for compliance with the target and updated RED and Fuel Quality Directive (FQD) legislation, and therefore 2016-17 should see further transport sector and biofuels policy announcements. Meeting the EU 2020 transport target is likely to require higher consumption of E10 within the EU28 (currently, widespread supply infrastructure exists only in France, Germany and Finland). For biodiesel, the limit on blending to 7% (by volume) according to the European EN 590 standard could represent a limiting factor, although current European Union-wide consumption is not close to this level.

Figure 3.5 EU28 ethanol production, (2009-21) (left), and biodiesel production, (2009-21) (right)



Sources: IEA (2016a), *Oil Information* (database), www.iea.org/statistics/; IEA (2016b), *Monthly Oil Data Service (MODS)* (May 2016), www.iea.org/statistics/.

If the target is to be met, there will be a role for fatty acid methyl ester (FAME) and HVO biofuels produced from waste oil and animal fat feedstocks, as these are double counted under the RED. However, feedstock availability will be a consideration in determining their overall contribution. These will need to be complemented by accelerated scale-up in the market shares of electric vehicles (EVs), as renewable energy sources consumed in electric road vehicles' contribution to the 2020 transport target are subject to a multiplier of five within the RED, coinciding with increasing shares of renewable electricity within key European EV markets (Germany, France, Norway, the Netherlands and the United Kingdom [UK]). Further cellulosic ethanol production capacity in the European Union and higher uptake of biomethane and E85 fuels are also likely to be needed if the target is to be met.

[12] Around 0.5 percentage points (including multiplier values specified in the Renewable Energy Directive [RED]) of this was sourced from renewable electricity with the rest from compliant biofuels or other renewable energies.

In 2015, EU28 biodiesel production, principally from rapeseed oil, shrank by around 8.5% versus 2014 levels, to just over 12 billion L. This was primarily due to reduced output from key producer countries France, Germany, Italy and the Netherlands, which was not fully offset by increases in Poland and Spain. In Germany, CPQ legislation requiring a reduction in the GHG emissions of products from the mineral oil industry, i.e. transportation fuels, by 3.5% came into force to replace a 6.25% (by energy) biofuels mandate. This resulted in reduced biofuel consumption, with blended biodiesel down 7% on 2015 levels and the blending share falling to 5.8% from 6.5% (F.O. Lichts, 2016e). This is because under the previous legislation, the compliance level was the EU RED requirement of 35% emissions reductions. However, within the CPQ, obligated parties (e.g. fuel blenders, refineries) focused on maximising emissions reduction per blended fuel volume.

For the EU28 forecasts, data are provided until 2020 in order to align with the timescale of the EU target of a 10% share for renewable sources in transportation fuel by 2020. Over the medium term, biodiesel and HVO[13] production is anticipated to rise gradually at an annual average growth rate of 5% to around 15.5 billion L in 2020, as growth is driven by the aforementioned target. EU diesel demand is stagnating as vehicle efficiency improvements are roughly offset by increasing stock (IEA, 2016d) and therefore it is anticipated that realising this production increase will require enhanced policy measures. As a consequence, uncertainty regarding post-2020 prospects for biofuels in the European Union is anticipated to result in a y-o-y decrease in production in 2021. In Germany, the scale-up of requirements in the CPQ to 4% over 2017-19 and 6% in 2020 should raise demand.[14] However, prospects for higher levels of FAME growth will be dampened by the European Commission’s introduction of a 7 percentage point limit on the contribution of biofuels produced from starch-rich, sugar and oil crops towards the 2020 target, which came into force within the revised RED and FQD in September 2015.

EU28 fuel ethanol production increased 6% y-o-y to reach 4.9 billion L in 2015 and should continue to grow at an annual average growth rate of about 3.5% to around 6 billion L by 2020, in line with the *MTRMR 2015* forecast. Key producer countries include France, Germany, Spain and the United Kingdom, and the main feedstocks used for ethanol production in 2015 were corn (37%), wheat (33%) and to a lesser extent sugar beet, with almost all feedstock sourced within Europe (EPURE, 2016). Higher growth is inhibited by declining EU28 gasoline demand, with annual reductions in the region of 2.4% (IEA, 2016d) and the introduction of the aforementioned 7 percentage point limit for conventional biofuels within the EU transport target.

Market prospects for E10 are positive in France, supported by a favourable taxation policy for ethanol, increasing gasoline demand (3% y-o-y) and growing fuel supply infrastructure (more than 58% of service stations offer the blend). As a result, the market share of E10 reached about 36% in early 2016, with y-o-y growth in 2015 assessed at around 6%. E85 fuel supply infrastructure is also increasing, although from a lower base, as 8% of service stations offer the blend (all E10 and E85 data for France, F.O. Lichts, 2016f). In Spain the biofuels mandate has been strengthened and will progressively increase to 8.5% by 2020 (MINETUR, 2015).

[13] HVO is counted in the conventional biofuels forecast where produced from a mix of vegetable oil and waste and residue feedstocks.

[14] However, the potential for upstream efficiency savings to count towards emissions savings, e.g. associated with reduced venting and flaring, within the CPQ could result in downside potential for biofuels.

Forecasting conventional biofuels production in the European Union post-2020 becomes uncertain with the expiry of the RED and FQD targets for 10% renewable transport and a 6% reduction in the GHG intensity of vehicle fuels. The EC policy framework covering climate and energy over the 2020-30 period introduces an overarching target for the European Union of a GHG emissions reduction of 40%[15] and a 27% share of renewable energy consumption across all sectors (EC, 2014). However, it is yet to be clarified if and how these targets will be allocated by member state.

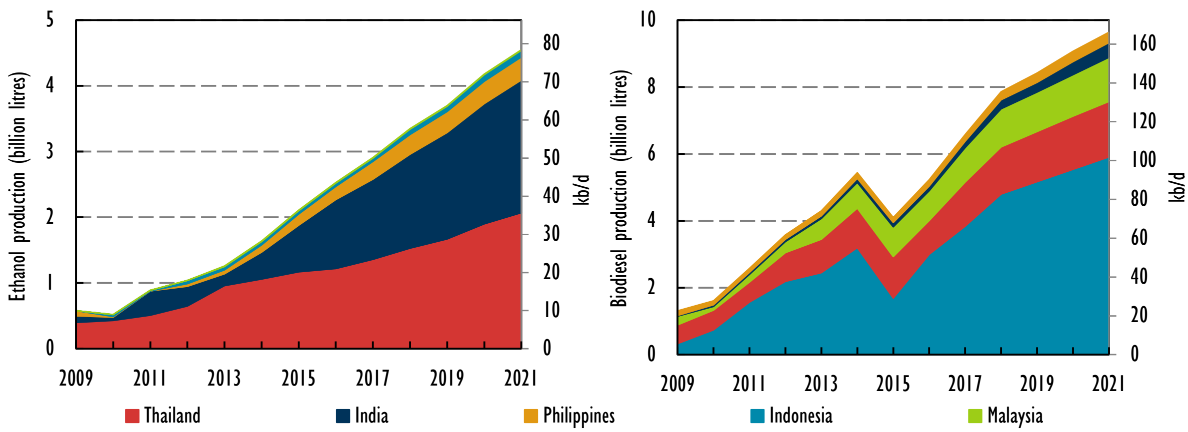
Based on the current status of the framework, a non-sector-specific and technology-neutral approach will be employed, with member states having flexibility as to how these overall targets are met. EC impact assessment modelling suggests a modest increase in renewable energy in transport over 2020-30 under the scenarios most reflective of the announced targets. It is unlikely there will be a continuation of the subsector target for transport after 2020, and as such the contribution required from biofuels is less clear as renewable electricity and heat will also contribute to the overall targets.

Uncertainty regarding the post-2020 outlook for biofuels is anticipated to both produce a downturn in conventional biofuels production in 2021 within the *MTRMR 2016* forecast and also diminish prospects for new capacity investment towards the end of the medium term. No support will be made available for food-based biofuels post-2020 under EC state aid rules, although investment aid to convert conventional biofuel plants into advanced biofuel plants would be allowed.

Significant growth potential in Asian conventional biofuels markets

Aside from the established markets already discussed, the *MTRMR 2016* forecast is increasingly driven by countries such as India, Indonesia and Thailand (Figure 3.6), where despite the low oil price environment, security of supply considerations have resulted in enhanced policy support for the production and consumption of domestically produced biofuels.

Figure 3.6 Ethanol (left) and biodiesel (right) production in selected Asian countries



Sources: IEA (2016a), *Oil Information* (database), www.iea.org/statistics/; IEA (2016b), *Monthly Oil Data Service (MODS) (May 2016)*, www.iea.org/statistics/.

[15] Based on 1990 levels, with the non-EU Emissions Trading System (EU ETS) portion of which allocated across member states.

In **Indonesia**, the largest biodiesel producer in Asia, the most significant developments in medium-term global biodiesel production are anticipated. Production dipped by almost 50% in 2015 to 1.7 billion L, caused by an interruption of financial support from delays in implementing legislation to move from a B10 to a B15 biodiesel programme. However, a range of policies have been introduced to stimulate the transition from an export-driven market towards higher domestic consumption. These include a subsequent increase in the mandate to a global high of B20, and the establishment of a fund to utilise levies on crude palm oil (CPO) and exports of palm oil products to cover biodiesel consumption premiums over petroleum diesel. Furthermore, mandates have been introduced for B20 within industry and B30 in electricity generation, which should further spur demand. As a result, a robust increase in production to almost 6 billion L by 2021 is anticipated, an upward revision compared with the *MTRMR 2015*. Despite this outlook, short-term growth could be undermined by an El Niño-related reduction in palm oil yields in 2016 and the capacity of national blending infrastructure.

Conventional biofuel policy support is also burgeoning in other oil-product-importing economies in Southeast Asia. An 11% y-o-y increase in ethanol production in **Thailand**, the largest producer in Southeast Asia, saw the industry produce 1.2 billion L in 2015. The medium-term forecast for ethanol is revised upward from the *MTRMR 2015* to just over 2 billion L in 2021, but could increase further spurred by the national Alternative Energy Development Plan (AEDP) 2015-36 targets of 2.55 billion L by 2026, which represents an average ethanol blend of 24% (DEDE, 2015).

Growth is characterised by an expanding share of E20 and E85 blends, which are subsidised to aid retail competitiveness, with the aspiration to eventually fully replace E10 with these from 2018. Growth will be supported by continuing development of the fuel distribution network for high blends and an increase in planted sugar cane area, as well as development of more cassava and molasses ethanol production. Market expansion has been achieved through a range of subsidies, e.g. for fuel distribution infrastructure, and tax incentives for flexible-fuel vehicles. Biodiesel production is also poised to increase in Thailand, from 1.2 billion L in 2015 at an average annual growth rate of 5% to around 1.7 billion L in 2021. The *MTRMR 2016* forecast anticipates an increase in the Thai biodiesel mandate from 7% to 10% during the medium term, as trials are under way to assess its feasibility.

In **Malaysia**, the introduction of a B7 biodiesel mandate resulted in a 16% y-o-y increase in biodiesel production (principally from palm oil) to 0.9 billion L in 2015. In the short term, high palm oil prices due to the impact of the El Niño weather event on oil palm yields are anticipated to push up biodiesel production costs. The increase to a nationwide B10 blend mandate[16] in the transport sector announced in June 2016, combined with a trend of increasing diesel consumption, results in an upward revision of the *MTRMR 2015* forecast. Production is anticipated to increase to around 1.3 billion L by 2021, but could grow faster depending on the timeline for national roll-out and compliance with the higher mandate. Higher production still could be achieved by the introduction of a nationwide B15 mandate, as outlined in the 11th Malaysia Plan for the 2015-20 period.

In the **Philippines**, ethanol production increased to 170 million L in 2015, and a boost to production from a number of new molasses plants coming on line is anticipated in 2016. Over the medium term, output is

[16] To be complemented by a B7 blending target for the industrial sector. The date of nationwide introduction of the higher mandates is not confirmed at the time of writing.

forecast to increase to 350 million L by 2021. A 10% fuel ethanol mandate is in place that is planned to increase to 20% by 2020. However, it remains to be seen if policy ambition can be matched by the ability of the biofuel industry to scale up accordingly. If this is not the case, ethanol imports would be required to meet any mandate increase. Biodiesel production is anticipated to double from 150 million L to 300 million L over the medium term, and assessments are under way regarding an increase from a 2% to a 5% mandate, which provides upside potential to the forecast.

In an upward revision to the *MTRMR 2015* forecast, ethanol production in **India** is anticipated to reach around 2 billion L in 2021, up significantly from 700 million L in 2015. Growth is anticipated as a result of new measures to strengthen the ethanol blending programme and meet the nationwide E5 blending mandate; these include a more attractive pricing mechanism for ethanol procurement from sugar mills and excise duty exemption for fuel ethanol used for gasoline blending, although potential changes to these add uncertainty to the forecast. Ethanol supply contracted in 2016 has increased and should result in a higher blend share, with levels closer to the 5% mandate requirements than previously achieved. It has been reported that the government has approved E10 blend sales by national oil marketing companies (OMCs), which if widely implemented would increase the likelihood of compliance (F.O. Lichts, 2016g) with both the E5 mandate and eventually the E10 target.

Capacity is already in place to expand ethanol output, although the measures mentioned above may result in a diversion from industrial to fuel ethanol production. The *MTRMR 2016* forecast anticipates India to move beyond the 5% mandate and towards the more ambitious 10% ethanol blending target, which is likely to require the availability of competitive finance to deliver additional investment in production capacity. Reaching the 10% blend target will be challenging and require actions to mitigate procedural barriers relating to inter-state permits, taxes and levies and constrained ethanol storage capacity at refineries, which have the potential to hamper growth. Stimulating ethanol consumption and production beyond 10% levels in the medium term is considered highly challenging under current market conditions.

Biodiesel production prospects have also improved in India. In 2015, approval was given for producers to sell pure biodiesel (B100) directly to bulk consumers such as the rail and shipping industries, without going through OMCs, with the excise duty on biodiesel production feedstocks also removed. Furthermore, plans are afoot for OMCs to supply retail B5 in several cities, and these have subsequently tendered for biodiesel supply, although no formal national mandate is in place. Production reached 130 million L in 2015 and is projected to grow to around 450 million L by 2021.

In **China**, the world's third-largest fuel ethanol producer, production of 2.75 billion L in 2015 is forecast to increase at an annual average growth rate of just under 5% to around 3.6 billion L by 2021. Growth is underpinned by robust gasoline demand growth as a result of the vehicle fleet expanding annually at just below 10% over the medium term (IEA, 2016d). With no announced plans to increase blend rates beyond E10, higher growth in ethanol consumption will depend on extending E10 standards to additional provinces. China increased fuel ethanol imports tenfold during 2015, as comparatively high corn prices pushed up the cost of domestic fuel ethanol production, making imports, particularly from the United States, attractive. In the short term, the potential sale of aged corn no longer fit for human consumption to ethanol producers at competitive rates, alongside reforms to allow corn prices to be set by the market and plans to change stockpiling policies for the grain, could reduce the prospects for imports.

Box 3.1 HVO poised to play an expanding role in transport decarbonisation

HVO,[17] commonly referred to as renewable diesel, is a biofuel produced from a range of feedstocks, including vegetable oils, animal fat from the food processing industry, used cooking oil (UCO), and industrial residues such as tall oil from the pulp and paper industry. HVO fuels consist of paraffinic hydrocarbon chains with properties almost identical to fossil diesel. As such, HVO is technically “drop in”, i.e. can be used unmodified without changes to common fuelling infrastructure or vehicle engines. Because of this, HVO blending in the European Union is not limited to the 7% level under the EN 590 diesel standard that is currently applicable to FAME biodiesel. However, the share of HVO is limited by the specifications of the standard due to its slightly lower density than fossil diesel, and is therefore still commonly blended.[18]

Where waste and residue feedstocks are utilised, HVO can deliver low life-cycle GHG emissions compared with conventional fossil diesel, as well as good operational properties in cold climates. Waste and residue feedstocks are typically available at lower costs than virgin vegetable oils but can present additional challenges in processing due to their variability. Availability of these feedstocks is ultimately finite; however, there is sufficient availability to allow for industry scale-up from current levels.[19]

HVO production is on an upward trend, with global production capacity exceeding 5 billion L, and plants currently operating at commercial scale in Singapore, the United States and several European countries. HVO plants typically have large rated production capacities in order to benefit from economies of scale. In 2015, a commercial-scale HVO plant using tall oil feedstocks came on line in Finland, while 2017 should see further capacity increases with two conventional oil refineries being converted to HVO plants in southern Italy and France. Furthermore, an increase in rated production capacity at another plant in the United States is anticipated. Upside potential for market growth is present from further conversion projects of non-profitable oil refinery assets to diversify product supply.

HVO consumption in the European Union reached about 2.2 billion L in 2015, with its share of EU biodiesel consumption increasing around 3 percentage points to 16% in 2015, an increase from around 2% in 2010 (F.O. Lichts, 2016h). HVO market prospects have been boosted recently as a number of major heavy-duty vehicle manufacturers (notably Scania, Volvo, MAN and Mercedes-Benz) have approved the use of unblended HVO (HVO100) in their vehicles, raising the prospect of higher uptake of HVO100 fuels in heavy-duty transport. In addition, the announcement of the EN 15940 standard for paraffinic diesel (CEN, 2016) also offers increased potential for the approval by passenger vehicle manufacturers for unblended HVO use.

HVO fuels able to deliver deep GHG reductions compared with conventional fossil diesel should be valued at a premium within schemes such as the LCFS in California, similar legislation in the province of British Columbia in Canada or Germany’s CPQ, which prescribe reductions in fuel CI[20] as shown by Figure 3.7. Therefore, market prospects should improve as the required CI reductions of fuels increase towards 2020 in these schemes.

Post-revision, California’s LCFS was reintroduced in September 2015. Based on data from the California Environmental Protection Agency Air Resources Board, around 625 million L of renewable diesel fuel produced from feedstocks such as tallow, fish oil and UCO was used within the LCFS in 2015. LCFS compliance credits for residue feedstock fuels rose above crop-based alternatives for the first time in 2015, with waste and residue renewable diesel and biodiesel contributing approximately equal shares.

[17] As well as hydrotreated vegetable oil, HVO is also referred to as hydrogenated vegetable oil, and renewable diesel in some markets.

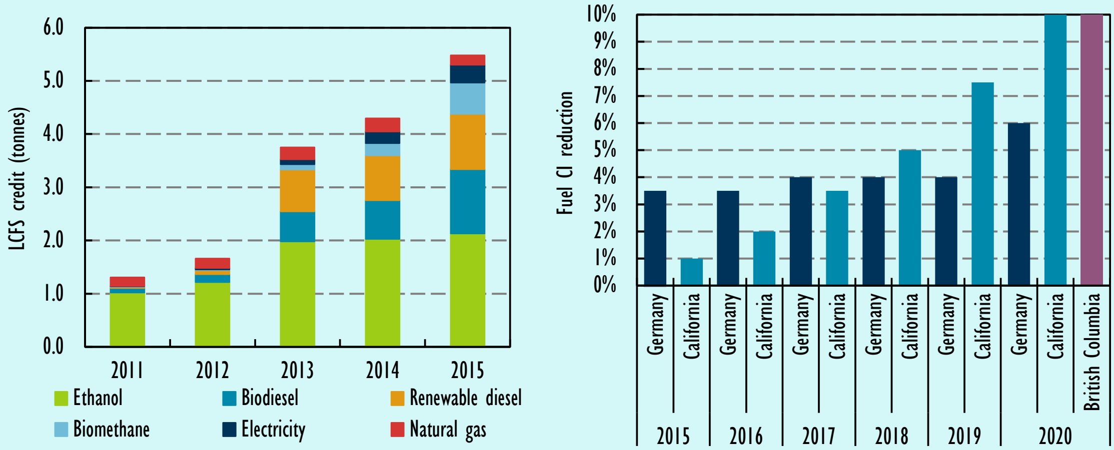
[18] Blends with both fossil diesel and biodiesel are available commercially.

[19] Production is also commonly undertaken in combination with virgin vegetable oils.

[20] CI may be defined differently within the legislation for the schemes referred to within the text; however, a general definition for CI would be a measure of the GHG emissions produced from the fuel on a life-cycle basis.

Box 3.1 HVO poised to play an expanding role in transport decarbonisation (continued)

Figure 3.7 Credits generated by fuel within California's LCFS, (2011-15) (left), and fuel CI requirements of legislation in California, Germany and British Columbia



Note: An LCFS credit reflects one tonne of reductions in GHG emissions.

Sources: California Environmental Protection Agency Air Resources Board (2016), *Data Dashboard*, www.arb.ca.gov/fuels/lcfs/dashboard/dashboard.htm, German Biofuel Association (2014), *Climate Protection Quota* and Government of British Columbia (2016), *Renewable & low carbon fuel requirements regulation*, www2.gov.bc.ca/gov/content/industry/electricity-alternative-energy/transportation-energies/renewable-low-carbon-fuels.

Beyond road transport, hydrotreated esters and fatty acids (HEFA)[21] fuels are approved under the American Society of Testing and Materials (ASTM) standard for commercial use in aviation within blends of up to 50% with conventional jet kerosene fuel. However, current production costs are higher than conventional jet fuels, particularly in the current low oil price environment.

Advanced biofuels market developments

The production of advanced biofuels, which have the potential in the longer term to sustainably reduce the overall carbon footprint of the transport sector, underwent further market developments over the last year. There is no globally recognised definition for advanced biofuels, with different interpretations of the term, as well as alternative terminology such as second-generation biofuels in use. For the purposes of the *MTRMR 2016,* advanced biofuels are sustainable fuels produced from non-food crop feedstocks, which are capable of delivering significant life-cycle GHG emissions savings compared with fossil fuel alternatives, and which do not directly compete with food and feed crops for agricultural land or cause adverse sustainability impacts.[22]

At a commercial scale, two advanced biofuels plants were commissioned in 2015: one advanced renewable diesel plant in Finland and a cellulosic ethanol plant in the United States. In addition, three smaller pilot and demonstration-scale cellulosic ethanol projects also came on line over 2015 and early

[21] The fuel produced is also referred to as HEFA synthetic paraffinic kerosene.

[22] Classification as "advanced" does not necessarily infer greater sustainability versus all conventional biofuels per se; however, making a distinction between conventional and advanced biofuels is useful when considering the level of technical maturity and requirements for policy support. HVO plants are included within the advanced biofuel forecast, where it is explicitly stated that exclusively waste and residue feedstocks are utilised for production.

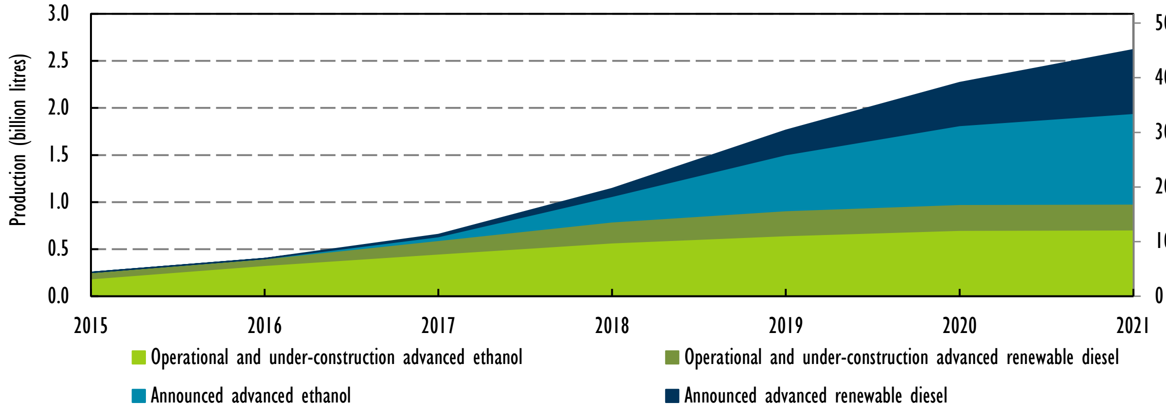
2016, including the first such plant in India. In 2016, a thermal pyrolysis plant using waste feedstocks to produce advanced renewable diesel in the United States and a tallow feedstock HVO plant in New Zealand are anticipated to start operations. Construction is planned to start at a further three commercial-scale plants in 2016, with one based in the United States producing aviation biofuel. Furthermore, 15 new advanced biofuel projects were announced during 2015 and early 2016, in locations such as the United States, China, India, the United Kingdom and Nordic countries, with 9 of these commercial scale.

Forecasting growth in advanced biofuels production over the medium term includes considerable uncertainty. It is understood that most of the first-of-a-kind commercial-scale advanced biofuel plants highlighted in the *MTRMR 2015* remain in the commissioning phase as they seek to increase production towards rated capacities. This extended commissioning period is explained by the fact that the technologies involved are first of a kind, and should be shorter for replication plants. These plants are therefore undergoing an intensive learning curve that includes "de-bottlenecking" in order to improve processes and therefore increase yield, and reduce investment and operational costs for the next generation of replication projects. Industry sources indicate that the key challenge is related to mechanical feedstock handling at large scale, as opposed to core fuel production processes. Whereas conventional biofuel feedstocks are uniform, agricultural residues used for cellulosic ethanol production are drier and contain higher levels of contaminants, posing additional challenges for handling and pre-treatment.

The timescale for resolving these issues is undefined and likely to be bespoke for each plant. In the first half of 2016, several plants showed a significant improvement in capacity utilisation, process performance and stability after having resolved process hurdles arising from moving to commercial-scale operations. In the United States, one commercial-scale cellulosic ethanol plant announced it was scaling up production in early 2016, although exact production volumes are not clear, while two other smaller plants are reported to be achieving consistent production (Governors Biofuels Coalition, 2016). However, a further commercial-scale plant is currently not operational for non-technical reasons. Most production and commissioning data is not publicly disclosed; however, for cellulosic ethanol plants located in the United States, RFS2 compliance figures from the US EPA reveal 8.2 million L of fuel production in 2015 (US EPA, 2016), which represents a utilisation rate of less than 5% of nameplate production capacity. Globally, if technical issues are resolved and output from commissioned and under-construction plants can scale up gradually to around 80% of rated capacity, production could reach just under 1 billion L by 202 as shown in Figure 3.8.

Prospects for expansion of the advanced biofuels industry are closely linked to the technical and financial performance of these first-of-a-kind plants demonstrating the feasibility of commercial-scale advanced biofuel production in order to bring through the pipeline of announced projects. Successful performance would provide opportunities for technology process providers to license their technology for use by third parties, standardise plant and process design, demonstrate successful large-scale supply chains, and reduce future investment risk. Full delivery and production scale-up of announced projects could increase advanced biofuel production to around 2.5 billion L by the end of the medium term (Figure 3.8). However, this is not guaranteed and will require key enabling factors such as access to secure and competitively priced local feedstock supplies and, in some cases, public-sector financial support to create a suitable investment climate given high investment costs. Even in the ambitious scenario of full delivery of all announced projects, advanced biofuels will still represent just 1.5% of forecast global biofuels production in 2021. As such, a significant scale-up in advanced biofuel production seems more likely beyond the medium term.

Figure 3.8 Advanced biofuels production forecast, (2015-21)



Future sector expansion is likely to be composed of both technology licensing and build-own-operate business models. Two companies behind projects within the first set of commercial-scale cellulosic ethanol plants covered in the *MTRMR 2015* have announced licensing and joint venture projects in China, with other replication projects announced in Malaysia and under construction in the Slovak Republic.

Significant agricultural residue availability results in good prospects for new market development in India. This is also the case in Thailand, where long-term ethanol consumption goals have generated interest in looking beyond sugar cane and cassava feedstocks, and the 2012-21 AEDP included an ambitious 2021 target of around 1 billion L of production by 2021. In Indonesia and Malaysia, potential exists to utilise palm oil industry residues as feedstocks for advanced biofuel production. Brazil already possesses two commercial-scale advanced biofuels plants, and the established ethanol industry should act as a key facilitator for an expansion of advanced biofuel production.

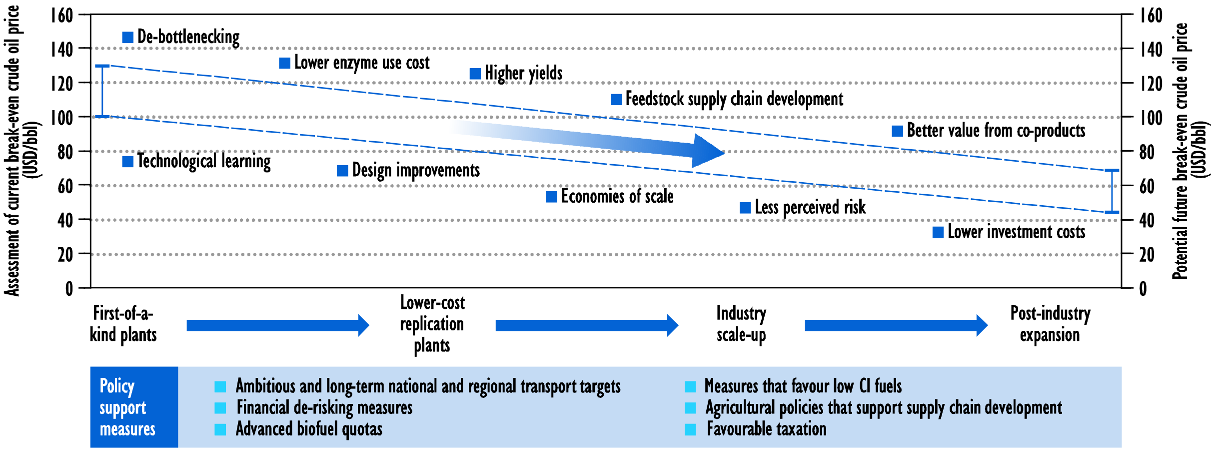
The attractiveness of investment in the advanced biofuels industry is likely to be dependent on a combined reduction in both the initial investment costs per rated capacity and operational costs per volume of fuel produced. While announcements indicate some lower-cost replication projects may be realised during the medium term, there is still significant room for innovation to deliver cost reduction and yield improvement potential in the industry. For example, the equivalent crude oil price at which current cellulosic ethanol production would be competitive (break-even oil price) is estimated to be in the region of USD 100 per barrel (bbl) to USD 130/bbl.[23] Break-even oil price may be lower where low-cost feedstocks are available, since costs for these can vary significantly by both feedstock type and location, e.g. linked to means of collection and labour costs.

Cost reduction and efficiency improvement trends previously observed in the conventional biofuels industry can be replicated within advanced biofuels, with significant potential identified to reduce production costs as outlined in Figure 3.9. Furthermore, it can also be assumed that more favourable financing conditions will be attainable for plants not considered first of a kind, therefore lowering investment costs. Achieving this

[23] Figures adjusted for energy content. Plant production cost data are confidential and as such the estimation above is based on reported industry cost projections made over 2014-16. Furthermore, cellulosic ethanol production costs are bespoke for the conditions at each plant.

potential could allow cellulosic ethanol plants to reduce break-even production costs to around USD 45/bbl to USD 70/bbl post-industry expansion (Figure 3.9). It should be noted that for bioenergy and biofuel projects, it has been observed that once demand for certain feedstocks is created, their associated prices can increase. As such it is important to ensure a balance between achieving competitive feedstock costs for cellulosic ethanol production with sufficient remuneration to mobilise feedstock supply.

Figure 3.9 Cellulosic ethanol cost reduction potential



Note: *Enzyme use cost* refers to the enzyme cost per hydrolysis output.

Synergies between conventional and advanced biofuel plants also exist. As reported in the *MTRMR 2015*, apart from the construction of large-scale advanced biofuel production facilities, alternative smaller-scale lower-investment-cost options are available. In addition to several projects in Brazil and Nordic countries, cellulosic ethanol technologies integrated with existing conventional ethanol plants have developed in the United States over the last year. One technology solution has been installed in six ethanol plants with further technology licensing agreements agreed (Ethanol Producer Magazine, 2016). While offering lower production capacity than dedicated plants, such an approach has significantly lower investment costs associated with infrastructure and logistics, and also benefits from access to residue feedstocks from conventional biofuel production and builds on existing industry experience. In addition, production from such plants is able to come on line quicker than dedicated new-build advanced biofuels plants.

Advanced biofuel policy considerations

Stable and long-term policy frameworks will be required to provide a more favourable investment climate to facilitate expansion of the advanced biofuels sector and enable the potential for a reduction in production costs. National transport sector targets for emissions reduction, shares of renewable energy or phasing out fossil fuels within the transport sector, such as Sweden's ambition to phase-out fossil fuel use in transport by 2030, provide a framework for advanced biofuels markets to prosper. Finland sits at the forefront of the advanced biofuels industry with widespread activity aimed towards meeting ambitious national targets to achieve renewable transport fuel shares of 20% by 2020,[24] twice the RED renewable energy in transport target, and 40% by 2030.

[24] Includes the provision for double counting of certain fuels.

The strengthening of specific policy support measures will also be essential to accelerating uptake. More widespread advanced biofuel quotas are likely to be the key means of supporting industry expansion. Such quotas create guaranteed demand, which where coupled with penalties for non-compliance can stimulate high off-take prices and provide investor confidence in revenue certainty and profitability. This is especially true in the context of a low oil price environment, which widens the advanced biofuel cost premium over fossil fuels. Apart from existing examples such as the cellulosic annual volume standards within the RFS2 scheme in the United States and advanced biofuel mandate due for introduction in Italy from 2018, limited new support policies have been announced since the *MTRMR 2015*.

In the European Union, the aforementioned revisions to the RED and FQD specify that member states should adopt a national sub-target for advanced biofuel consumption in 2020 within 18 months of the legislation coming into force, with a non-mandatory reference value of 0.5 percentage points suggested. This would indicate that further advanced biofuel mandate announcements can be expected in the time period up to the second quarter of 2017. In Denmark, plans are afoot for a 0.9% technology-neutral advanced biofuels mandate for transportation fuel by 2020 (Biofuels International, 2016). Separate energy-based advanced biofuel targets have also been established in France; these are 1.6% by 2018 and 3.4% by 2023 for gasoline and 1% by 2018 and 2.3% by 2023 for diesel (Legifrance, 2016). The European Commission includes advanced biofuels in a wider set of measures for the decarbonisation of the transport sector post-2020 and recognises that incentives to increase innovation and deployment of these are likely to be required.

The provision of financial de-risking measures to support industry expansion while initial investment costs remain high is also likely to be necessary. Previous examples in this area include the Brazilian development bank, BNDES, offering financial support for biofuel innovation, loan guarantees from the United States Department of Agriculture and an Advanced Biofuels Demonstration Competition in the United Kingdom. Advanced biofuels are also eligible for support via the European Commission's Horizon 2020 framework programme for research and innovation. Wider measures also beneficial to the development of the advanced biofuel market include fuel tax incentives, financial mechanisms to support technological innovation and working with the agricultural sector to develop competitive regional biomass supply chains. Agricultural policies that promote residue collection and aggregation, as well as the establishment of energy crops, e.g. energy cane in Brazil, will also be a key means to deliver cellulosic ethanol production cost reductions.

Legislation to stipulate defined reductions in the life-cycle CI of transportation fuels such as the schemes already mentioned in British Columbia, California and Germany should ensure demand for biofuels with the highest emissions reduction potential, which naturally favours those produced from waste and residue feedstock. However, under such technology-neutral approaches, demand for advanced biofuels will be determined by the ratio of cost margin versus emissions reductions offered compared with other means of decarbonisation. As a result, while beneficial in the long term, the lack of guaranteed demand volumes means these policies may not provide as much investor confidence in the advanced biofuels industry as a dedicated quota. In Brazil, cellulosic ethanol is treated equally to conventional ethanol under the national blending mandate, and therefore production may be destined for export markets where premium prices can be achieved.

Box 3.2 Aviation biofuels: Ready for take-off during the medium term?

In OECD countries, aviation activity increased faster than all other non-urban transport modes in the last decade and globally is projected to continue to grow at a rapid pace beyond the medium term, especially in non-OECD countries (IEA, 2016c). While emissions from aviation do not sit within the COP21 global climate agreement, the International Air Transport Association (IATA) has adopted its own set of ambitious targets to reduce the climate impact from air transport, including carbon-neutral growth from 2020 and a reduction in net aviation CO_2 emissions of 50% (on 2005 levels) by 2050 (IATA, 2016a). There will be a significant role for aviation biofuels if these targets are to be achieved, and as such these are expected to be a key driver within the advanced biofuels market forecast. Opportunities for decarbonisation via electrification within aviation are minimal compared with light-duty vehicles, and while the International Civil Aviation Organization (ICAO) has agreed to an aircraft CO2 emissions standard that outlines efficiency standards for existing jets from 2023 and new jets from 2028 (ICAO, 2016), meeting industry decarbonisation targets will necessitate a move to lower-carbon fuels.

With regard to alternatives to conventional fossil kerosene, the aviation industry requires biofuel solutions produced from feedstocks with low price volatility, used in processes with scale-up potential to produce “drop-in” fuels, i.e. compatible with existing engines and fuel supply infrastructure, certified to recognised industry standards. Only aviation biofuels that meet industry standards, such as ASTM D1655 and ASTM D7566[25] and the UK Defence Standard (Defstan) 91-91, can be utilised. Currently there are four principal technology processes for producing renewable jet fuel. These include HEFA, Fischer-Tropsch (FT), alcohol-to-jet (ATJ) and direct sugars to hydrocarbons (DSHC[26]); all of which are now ASTM D7566-approved at different blend levels. Aside from decarbonisation purposes, long-term benefits to the aviation industry from aviation biofuel consumption include supply diversification and proactively hedging against the potential for regulatory and carbon taxation costs, e.g. carbon taxation within the aviation sector, in the future.

The safety and suitability of certified aviation biofuel use within commercial aircraft have been demonstrated by more than 2 000 flights performed by over 20 different airlines (IATA, 2016a). In 2015-16, key industry developments included the use of aviation biofuels in a 30%/70% biofuel blend with conventional fossil kerosene, procured via a multi-year off-take agreement, within regular flights from Los Angeles by a major US airline. This represents a move beyond demonstration flights and promotional activities to regular commercial operation. The biofuels in question are produced from non-edible feedstocks in a converted refinery complex located within the state of California. The same airline is also looking to support commercialisation via direct investment in another aviation biofuel plant project that plans to use a gasification and FT process to produce aviation biofuel.

In addition to this plant, a further two commercial-scale aviation biofuel refineries plan to commence construction over 2016-17. Other long-term off-take agreements were also agreed between airlines and prospective aviation biofuel suppliers in the United States, resulting in the first commercial flights using aviation fuel blends produced via the ATJ process in 2016. Such off-take agreements are particularly essential in providing investor confidence in advanced biofuel refinery projects to ensure the delivery of new capacity.

[25] ASTM D1655: Standard Specification for Aviation Turbine Fuels; ASTM D7566: Standard Specification for Aviation Turbine Fuel Containing Synthesized Hydrocarbons.

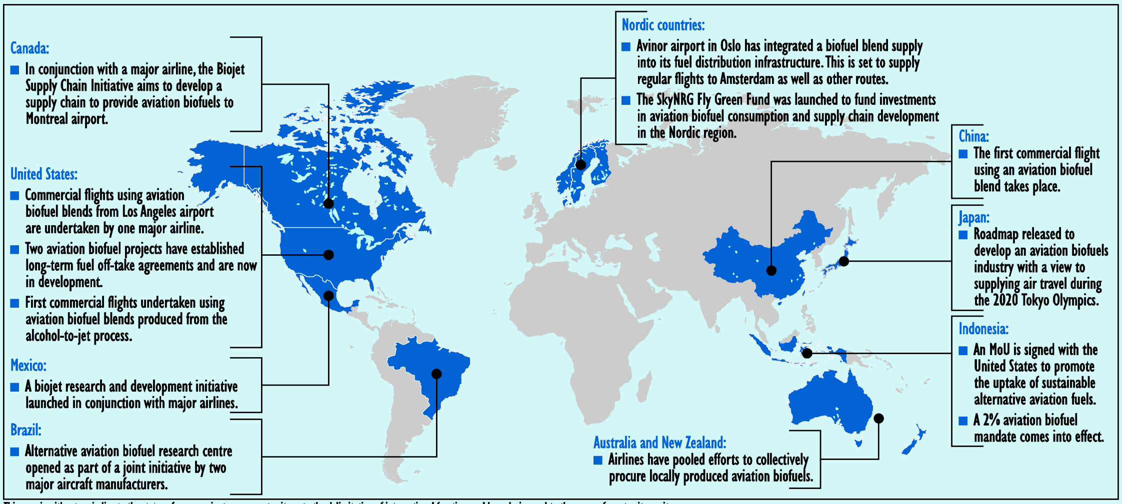
[26] DSHC is also referred to as synthesised iso-paraffin. Other aviation biofuels production processes include FT synthetic paraffinic kerosene and synthetic paraffinic kerosene with aromatics.

Box 3.2 Aviation biofuels: Ready for take-off during the medium term? (continued)

Industry scale-up during the medium term will require the development of regional supply chains, through clustering airlines, advanced aviation fuel suppliers, and airport storage and distribution infrastructure. "Bioport" initiatives include Oslo (Avinor) airport, which has integrated a 50% aviation biofuel blended supply, available to all airlines using the airport, and a dedicated aviation biofuel pump at Karlstad airport in Sweden. Canada's national airline is participating in a Biojet Supply Chain Initiative established with the aim of supplying aviation biofuels from Montreal airport.

An all-time high number of aviation biofuel initiatives (e.g. deployment, stakeholder agreements, research and development programmes, etc.) where announced in 2015 (IATA, 2016a), and increased deployment is anticipated to account for a growing share of the *MTRMR* advanced biofuels forecast moving forward.

Map 3.1 Global aviation biofuel developments over 2015-16



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

Note: MoU = memorandum of understanding.

Source: IATA (2016a), *IATA 2015 Report on Alternative Fuels*.

Current barriers are more economic than technical because the aviation industry is not able to pay a premium for biofuels without loss of competitiveness. Currently, aviation biofuels are two to four times the cost of conventional fossil kerosene, with the premium dependent on factors such as feedstock cost, biofuel production process, oil prices and customer specifications (regarding feedstock, blend ratio, length of delivery period, etc.). Where incentives are in place, such as RINs or RED biotickets, the cost premium is reduced. Biotickets are produced for biofuels blended with transport fuels used in the Netherlands, including in the aviation sector, and can be used by obligated parties to ensure compliance with the requirements of the national biofuels quota. As such, a combination of achieving advanced biofuel cost reductions, policy support and financial innovation are needed to stimulate aviation biofuel consumption. In the absence of aviation industry carbon taxation or other mechanisms to cover the price premium, a reduction in production costs will be essential to stimulate aviation biofuel market growth. As with all advanced biofuels at this early stage of market development, production costs are highly bespoke and will be dependent on feedstocks used and the technological processes employed.

Box 3.2 Aviation biofuels: Ready for take-off during the medium term? (continued)

Achieving cost reductions is likely to be closely linked to industry scale-up from the current limited number of dedicated production plants. In this respect, initiatives such as European Advanced Biofuels Flightpath, which aims to support an increase in aviation biofuel production capacity in Europe and facilitate the consumption of 2 million tonnes of aviation biofuels in 2020, will be of value (EC, 2016).

Examples of policy frameworks for aviation biofuels are now starting to emerge:

- Under the US RFS2, biofuels for aviation are eligible to generate RINs.
- EU legislation was amended so member states may permit aviation biofuels to be used in compliance with the 2020 RED renewable target for transport.
- The Norwegian government proposed a 25% landing fee reduction for flights using at least 25% biofuel.
- Indonesia introduced a 2% biofuel mandate for aviation fuels in 2016 (IATA, 2016b).

In the absence of a combination of dramatic production cost reductions coupled with crude oil price increases, these and additional measures will be required during the medium term to cover the cost premium of aviation biofuels compared with conventional jet kerosene. Such options include the SkyNRG Fly Green Fund, launched in 2015, to facilitate corporate bodies, organisations and individuals to pay an air travel premium destined to fund investments in aviation biofuel consumption and associated supply chain development in the Nordic region.

Impacts of low oil prices on conventional and advanced biofuels markets

This section provides analysis of the impacts on global biofuels markets that have been observed from the significant reduction in global crude oil prices observed in mid-2014 and consequent sustained period of depressed oil prices since, in addition to an evaluation of the potential effects of a sustained low oil price environment on prospects for biofuels during the medium term.

Policy support remains strong in key markets, protecting production and consumption

Biofuel consumption remains largely mandate-driven, and despite a low oil price environment, biofuels mandates proved effective in protecting the industry from direct competition with lower-priced gasoline and diesel over the last year. As stated previously, global biofuels production increased in 2015. Ethanol production increased in both OECD and non-OECD regions in 2015, and while biodiesel production did contract slightly, the volume reduction can be explained by the transition to new biofuel support policies in Indonesia and Germany.

Biofuels demand in a given market is subject to multiple conditions and there are limitations to making high-level conclusions regarding the impact of oil prices alone. With regard to consumption, in the United States and Brazil, ethanol consumption increased in 2015. In the United States, lower fossil fuel prices pushed gasoline prices downward, stimulating an increase in consumption and consequently increasing the volume of the blended ethanol share. While in Brazil, higher taxes on gasoline tipped prices in favour of hydrous ethanol use for a large portion of the year, causing a sharp upturn in demand. In Sweden, fuel ethanol sales reduced y-o-y as demand for E85 declined by 40% (F.O. Lichts, 2016i). However, this was caused due to a combination of increased E85 taxation and lower gasoline prices.

IEA analysis indicated that biofuel subsidies amounted to USD 23.5 billion[27] in 2014 (IEA, 2016f). The *MTRMR 2015* raised the possibility of a downside risk to the biofuels production forecast due to the potential for policy makers to reduce, delay or abandon biofuel policy support should low oil prices persist. However, biofuels policy support has increased in a wide variety of key markets since the downturn in oil prices. For example, mandates and supportive biofuel policies have been strengthened in Argentina, Australia, Brazil, India, Indonesia and Spain.

While it is hard to speculate on policies that have not been introduced or abandoned, there are some instances where policy support has wavered due to lower oil prices. It has been reported that the award mechanism for biofuel support incentives was switched from a "first come, first served" approach towards competitive bidding as a result of higher biofuel price margins at low oil prices in South Africa (Biofuels International, 2015b), and that higher biodiesel (coconut methyl ester) cost premiums over conventional fossil diesel in the Philippines are a contributing factor to ongoing deliberation over an increase in the national biodiesel blending mandate to 5% (Platts, 2016). Although not evident on a widespread basis as yet, the potential for policy support to be affected by a prolonged period of low oil prices is still considered a downside risk to the *MTRMR 2016* forecast. As outlined previously, the aviation industry's interest in alternative fuels relates to long-term strategic interests and is unlikely to be derailed by the current low oil price environment. However, in the United Kingdom, lower oil prices were reported to be one of a number of factors in the cancellation of one aviation biofuels project.

Varied and market specific effects do arise from lower oil prices

Lower oil prices have compromised biofuels prospects with specific effects evident on a market-by-market basis. First, cheaper petroleum products challenge biofuel blending economics by making the biofuel element relatively more expensive. One of the principal effects observed from this is to limit opportunities for discretionary blending above mandated levels that arise at higher oil prices. These effects should mainly be observed in export-driven markets; for example, biodiesel production in 2015 dropped 25% y-o-y in Argentina. It should be noted that discretionary blending markets are far smaller than mandated demand, and the policies of importer countries generally affect trade prospects to a greater degree than discretionary blending opportunities.

Overall, it can be stated that increasing biofuel spreads over gasoline and diesel do represent a challenge to the biofuels industry. Lower oil prices are a core element of these, with the other key contributing factor being feedstock prices that link closely to harvest results. For example, in the short-term, El Niño-induced reductions in palm oil harvests, e.g. in Malaysia and Indonesia, should increase CPO prices and in turn palm oil biodiesel spreads over conventional diesel.

The consequence of relatively higher biofuel costs is the incentive to minimise blend shares. This can occur especially where targets are in place instead of binding mandates and in markets where strong monitoring and governance arrangements are absent. Alternatively, in schemes where surplus compliance credits have been historically produced, obligated parties may choose to use these, or purchase scheme credits when biofuel premiums are elevated rather than blend physical volumes. However, wider market factors also influence these decisions. For example, during 2016, with the

[27] Figure converted from original value in order to express in USD 2015.

biodiesel blenders' tax credit in place in the United States, blending within the RFS2 programme appears to be favoured over the use of surplus or traded RINs as y-o-y biomass-based diesel RIN production from January to May increased by over 30%. Such decisions may also be time-bound; for example, obligated parties may have sought to reduce blending in early 2016 with oil prices in the region of USD 30/bbl in the anticipation that these would increase later in the year. In India, reports suggest some ethanol plants resorted to storing fuel on site as sales slowed at the start of the year.

The structure of some policy mechanisms is also compromised at low oil prices. In Indonesia, biodiesel consumption premiums compared with petroleum diesel are covered by income from a fund sourced from levies on CPO and palm oil product exports. As such, the volume of biodiesel consumption that can be subsidised is reduced where low oil prices mean the biodiesel cost premium increases. This may pose a downside risk to meeting mandated volumes, and heightens forecasting uncertainty since demand may be influenced by both oil prices and the level of CPO and palm oil product exports. A similar situation is present in Thailand, where levies on motor fuels are deposited in a state oil fund partly utilised to subsidise high E20 and E85 blends (not subject to the levy). Due to lower oil prices, the level of subsidisation of high ethanol blends required to maintain retail competitiveness rises, as was the case with both E20 and E85 subsidies in 2015.

Table 3.3 Assessment of low oil price impacts on the biofuels industry

Impact	Observed since oil price reduction?	Potential to occur in extended low oil price environment?	Additional comment
Decrease in consumption in key global markets related to oil price	✗	✓	2015 ethanol consumption was strong in key markets, including the United States and Brazil.
Decrease in global biofuels production	✗	✗	Global biofuels production is forecast to rise 2015-21 at an annual average growth rate of 3%.
Reduced policy support	✗	✓	Policy support strengthened generally, but the design of some policies raises the risk of mandate reductions in some markets with prolonged low oil prices.
Increased difficulty to attain new capacity investment	✓	✓	Appetite for investment in distressed assets and new-build capacity has decreased, although this can also be linked to other factors. This may be especially relevant for advanced biofuels.
Compromised blending economics	✓	✓	Blending economics are challenged by lower petroleum product prices. However, the associated impacts depend on policy mechanisms and strength of governance.
Discretionary blending opportunities limited	✓	✓	Likely to be relevant while oil prices continue to be low and principally affect export-driven markets.

While mandate policies create captive demand, they do not necessarily guarantee profitability. Significant biofuel production capacity is currently available for purchase in both the United States and Europe, while as outlined earlier the financial situation of many sugar mills in Brazil remains fragile. The appetite to invest in the purchase of distressed assets or new-build capacity is likely to be compromised within a low oil price environment, as potential investors require assurances that business cases remain intact and assess the impact on fuel off-take prospects. The challenge of obtaining financing is likely to be exacerbated for advanced biofuel technologies, which face additional financing challenges associated with technology risk as well as less widespread policy support. A number of reported project timelines are slipping due to extended timescales needed to secure investment.

In conclusion, suggestions of a dramatic downturn in biofuels consumption and production as a result of lower oil prices appear to be overblown at the current time, and it must be taken into account that oil prices are only one determining factor in biofuel market prospects. Since the reduction in oil prices, global biofuels production increased in 2014 and 2015, consumption remains healthy in key markets, and policy support has generally been strengthened. Conversely, it is clear that some market-specific adverse effects may manifest themselves in the short-term as a result of compromised blending economics and towards the end of the medium term due to a reduction in new capacity investment. The combination of these may undermine conventional biofuels markets to a degree and cause a downward shift from the *MTRMR 2016* medium-term forecast.

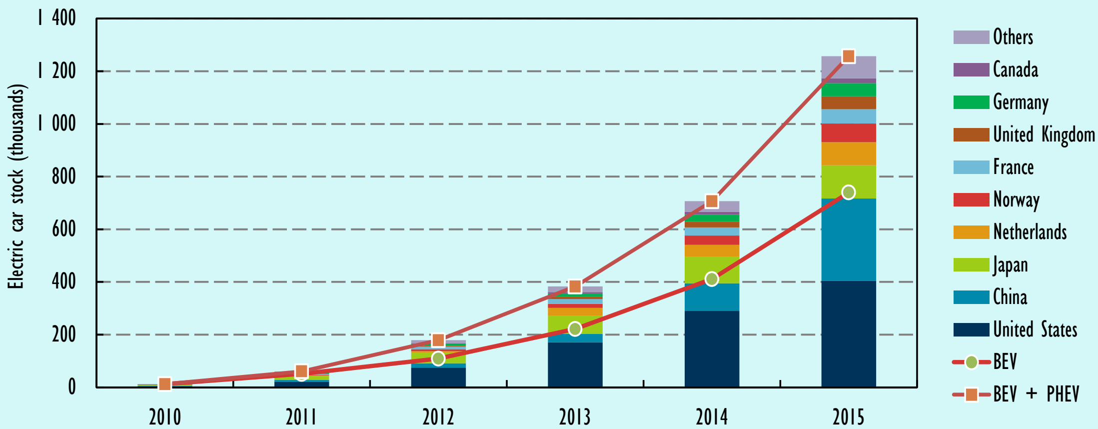
Box 3.3 An update on market, technology and policy developments for EVs

All figures provided within this feature box have been obtained from the IEA *Global EV Outlook 2016*.

Global status of electrified road transport in 2015

During 2015, the global threshold of 1 million electric cars on the road was exceeded, with deployment reaching 1.26 million. Electric cars include battery electric vehicles (BEVs), plug-in hybrid electric vehicles (PHEVs), and fuel-cell electric vehicles. However, the scope of this feature box is limited to BEVs and PHEVs and references to electric cars and EVs used in this chapter relate exclusively to these two categories. The global electric car fleet has been scaling up rapidly since 2010, with BEV uptake slightly ahead of PHEV uptake and 80% of the electric cars on the road located in the United States, China, Japan, Norway and the Netherlands.

Figure 3.10 Evolution of the global electric car stock, (2010-15)



Note: the EV stock shown here is primarily estimated on the basis of cumulative sales since 2005.

Source: IEA (2016g), *Global EV Outlook 2016.*

Box 3.3 An update on market, technology and policy developments for EVs (continued)

Ambitious targets and policy support have lowered vehicle costs, extended ranges and reduced consumer barriers in a number of countries. In terms of market shares of electric cars, Norway (23%) and the Netherlands (nearly 10%) lead the way, while with shares above 1%, deployment is growing in Sweden, Denmark, France, China and the United Kingdom. Booming electric car sales in China made it the principal market worldwide in 2015, overtaking the United States.

The electrification of road transport modes other than cars, namely two-wheelers, buses and freight delivery vehicles, is so far limited to a few localised areas. With an estimated stock exceeding 200 million units, China is the global leader in the electric two-wheelers market, with uptake linked to restrictions on the use of conventional two-wheelers in several cities as a measure to reduce local air pollution. By displacing conventional internal combustion engines (ICEs), EVs deliver immediate benefits for air quality in urban areas thanks to zero tailpipe emissions (in electric driving mode for PHEVs), as well as offering reduced noise level. China is also leading the global deployment of electric bus fleets, with more than 170 000 buses already circulating today.

Charging infrastructure and battery characteristics

Substantial new implementation of EV supply equipment (EVSE) was also observed in 2015, with policies encouraging the roll-out of publicly accessible charging infrastructure via direct investment and public-private partnerships. The number of publicly accessible charging outlets reached 190 000 globally at the end of 2015, of which 28 000 were fast chargers.

Battery costs have been cut by a factor of four since 2008, while energy density increased by a factor of five. These trends will be required to continue to enable more economical and longer ranges for electric cars. Recent carmaker announcements suggesting that EV ranges will soon exceed 300 kilometres give encouraging signals for the future. However, further technological progress and economies of scale in battery production will be critical to move towards cost parity with conventional ICEs.

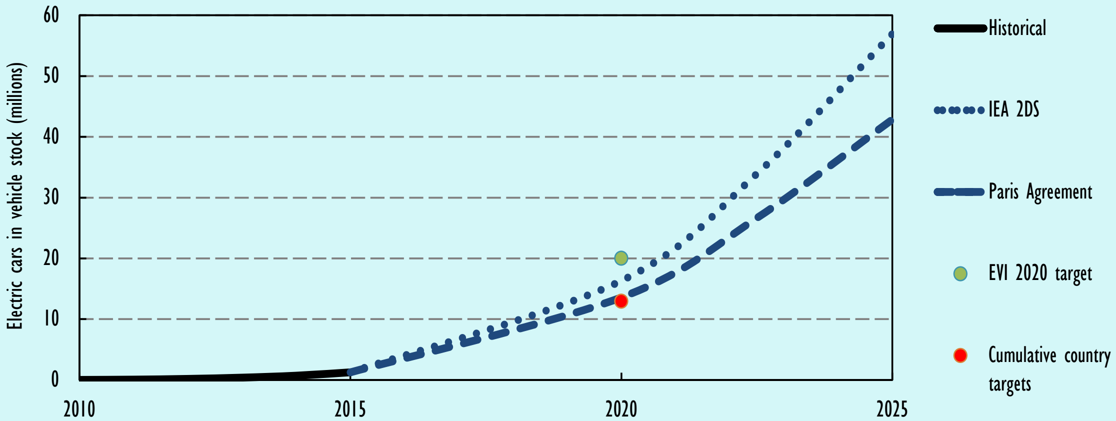
Post-2015 opportunities and challenges in road transport electrification

The Electric Vehicle Initiative's (EVI) 20 by 20 target calls for a global electric car fleet of 20 million by 2020, while the Paris Declaration on Electro-Mobility and Climate Change and Call to Action announced at COP21 sets a global deployment target of 100 million electric cars and 400 million electric two- and three-wheelers by 2030. Meeting these targets will require substantial market growth of the global electric car fleet, the rapid deployment of electric two-wheelers and buses beyond the Chinese market, and growth in electrified road freight vehicles, with urban deliveries a logical starting point.

EVs are well positioned to diversify the energy mix in transport. The efficiency of EVs is also well suited to deliver climate change-related benefits, but GHG emission savings can be maximised only where EVs are coupled with a low-carbon power generation mix, and as such the GHG reduction potential of EVs goes hand in hand with the expansion of renewable electricity technology deployment in the power sector. Globally, the share of renewables in total power generation is expected to increase from over 23% in 2015 to around 28% in 2021. Investment in EV roll-out can support this transition by providing opportunities to integrate variable renewable energy generation.

Box 3.3 An update on market, technology and policy developments for EVs (continued)

Figure 3.11 Deployment scenarios for the stock of electric cars to 2030



Note: 2DS = 2°C Scenario.

Source: IEA (2016g), *Global EV Outlook 2016.*

Policy considerations

EVs of all types will be a key contributor to future sustainable transport systems. Industry, governments and early adopters have succeeded in demonstrating that electric cars can deliver the practicality, sustainability, safety and affordability characteristics expected from them, but the EV market still requires policy support to build on and accelerate the momentum that characterised EV deployment since 2010 and to achieve widespread adoption and deployment.

Interconnection between different EV policy support mechanisms, as well as the emerging nature of EV markets and EVSE networks, make it challenging to identify an optimal way to encourage EV uptake, although financial incentives and the availability of charging infrastructure are factors that positively correlated with the growth of EV market shares. However, as the cost differential between EVs and ICEs shrinks, financial incentives will need to scale down. The progressive tightening of fuel economy standards and pollutant emissions regulations are also key tools to stimulate EV deployment, given the good energy efficiency and pollutant abatement performance of EVs and especially BEVs.

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4. RENEWABLE HEAT

Highlights

- Heat accounted for over half of global final energy consumption in 2014, with use for space and water heating in buildings, for cooking, and to operate industrial processes. Currently, since fossil fuels dominate heat production, the sector is responsible for a significant share (39%) of energy-related global carbon dioxide (CO_2) emissions.
- Modern renewables, excluding traditional use of solid biomass, provided around 7.2% of global heat demand in 2014. In addition, renewable electricity provided another 1.5% of heat demand. The European Union (EU) is the biggest producer of renewables for heat, followed by North America. Of the emerging economies, Brazil stands out in meeting 37% of its heating needs (primarily industrial) from renewables. In 2014, the majority (56%) of renewables for heat was consumed in industry, compared to a combined 44% from the buildings and agriculture sectors.
- Over the medium term, modern renewable consumption for heat is forecast to grow by 21%, from 15.2 exajoules (EJ) (363 million tonnes of oil-equivalent [Mtoe]) in 2014 to 18.3 EJ (437 Mtoe) in 2021. The share of renewables for heat is projected to increase to 8.2% (10% including renewable electricity for heat) as renewables meet one-quarter of the projected 6% growth in heat demand by 2021. This growth will come primarily from the People's Republic of China (hereafter "China"), the 28 EU member states (EU28), North America and India.
- Bioenergy (excluding traditional biomass) accounted for the largest share (89%) of direct renewable heat use in 2014. Solar thermal and geothermal technologies made a smaller contribution but are scaling up rapidly. This trend is anticipated to continue in the medium term, with 65% growth for solar thermal and 75% for geothermal over the period 2014-21. Despite growing contributions from other renewable heat technologies, bioenergy is still expected to account for 85% of direct renewables for heat in 2021.
- Renewable heat markets face multiple economic and non-economic barriers that need targeted policy support. A variety of instruments is in place across diverse markets, often with a particular focus on the buildings sector and linked to energy efficiency policies. Carbon taxation, fiscal incentives, renewable district heating and requirements for renewable heat in building standards have proved to be effective. The European Union's Renewable Energy Directive (RED) has driven renewable heat deployment in many member states, making a key contribution to the nine countries that achieved their RED targets by 2014.
- Residential heating oil prices declined significantly in 2015, with an average reduction of 33% within member countries of the Organisation for Economic Co-operation and Development (OECD), resulting in lower operational cost savings from renewable systems compared with oil boilers. Lower-cost fossil heating fuels appear to be a factor in year-on-year (y-o-y) reductions in wood pellet boiler installations in France, Germany and Italy. However, impacts are not observed in all countries, and adverse effects on solar thermal and heat pump markets are less evident. While a sustained period of lower fossil heating fuel prices poses an additional challenge for renewable heating solutions, it should be noted that multiple factors (such as changes to policy support) influence uptake of renewable heat in a given country.

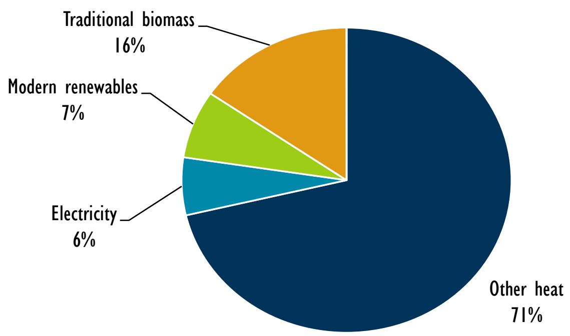
Renewable energy use for heat: Market trends and outlook

Global overview

Heat is being used for space and water heating in buildings, for cooking, and to operate industrial processes. Globally, over half (54%) of final energy consumption is for heat, equating to 211 EJ (5 041 Mtoe) in 2014, the base year used for most of this chapter, owing to data availability.[1] This figure includes the traditional use of solid biomass, which in 2014 accounted for around 16% of global heat demand, although there is a lot of data uncertainty (Box 4.1). Electricity provided 6% of heat. More than 70% of heat demand comes from the direct combustion of oil, coal or natural gas. The demand for heat is an important contributor to CO_2 emissions and, in 2014, accounted for around 12.4 gigatonnes of CO_2, or 39% of annual energy-related emissions. Renewable heat plays an important role in decarbonising heat supply, together with heat electrification (mainly through heat pumps) and improvements in energy efficiency (Box 4.5).

Cooling is also an important and fast-growing energy service demand in buildings and industry. Currently, space cooling accounts for about 2% of global energy consumption. Most cooling demand is met by electrical appliances such as air conditioners. While there are some renewable options for cooling (e.g. solar absorption chilling), the *Medium-Term Renewable Energy Market Report (MTRMR) 2016* does not cover cooling in this chapter given the relatively minor role of renewables, as well as a lack of available data.

Figure 4.1 Total global energy consumption for heat, (2014)



Source: IEA (2016a), *World Energy Statistics and Balances 2016*, www.iea.org/statistics/.

This report focuses on “modern” renewable heat technologies, i.e. traditional biomass consumption is excluded. Modern renewables accounted for 15.2 EJ of heat in 2014, which provided 7.2% of heat demand. These technologies comprise:

- Bioenergy – primarily biomass boilers that can be used in residential and commercial buildings, in district heating systems, or to produce industrial process heat across a range of temperatures and pressures. Biomass co-generation[2] systems are also in use. They can produce heat for district heating systems or industrial heat needs, as well as electricity.

[1] The 2016 renewable heat analysis uses results from the New Policies Scenario of the 2016 *World Energy Outlook* modelling. The scenario is based on existing energy policies, as well as an assessment of announced intentions, notably those in the climate pledges submitted for COP21. The baseline for the modelling is 2014 because this represents the latest year for which historical data are available from International Energy Agency (IEA) statistics.

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

- Solar thermal – used mainly for water heating in individual buildings and sometimes also to support space heating. In addition, it is used to supply to district heating systems, and in some industrial applications such as low-temperature heat in the food and textile industries and high-temperature process heat in enhanced oil recovery (EOR).
- Geothermal – the direct use of geothermal heat in industry or district heating systems. This can be at low, medium or high temperature. Low-temperature geothermal heat may be used in conjunction with heat pumps.

Box 4.1 Traditional use of biomass use meets a large share of heat demand in the developing world

The traditional use of solid biomass in the form of firewood, charcoal, manure and crop residues continues to play a major role in sub-Saharan Africa and parts of Asia, especially in rural areas. It is used by 2.7 billion people, mainly for cooking in inefficient cook stoves, and constitutes a very inefficient use of biomass. In addition, it also causes air pollution and is associated with severe respiratory diseases, as well as being implicated in deforestation. However, people in these areas lack access to modern energy services and generally have little choice but to continue using biomass.

Since 2007, the use of traditional biomass has increased by 9%. However, its use is expected to start declining due to initiatives such as Sustainable Energy for All (SE4All). The recent IEA *World Energy Outlook* special report on energy and air pollution suggests that the use could be cut by two-thirds by 2030, thereby also preventing 2 million premature deaths globally (IEA, 2016b). In most cases, traditional biomass use for cooking is replaced by liquefied petroleum gas (LPG), but renewable options include biogas systems, solar stoves and electric induction cooking that can be powered by solar PV.

In addition, renewables also play a role indirectly through the use of electricity for heat, either through resistive heating or, more efficiently, heat pumps. In some jurisdictions, heat pumps are defined as renewable, while in others they are considered primarily an energy efficiency technology. In reality, they are both, since a proportion of the final heat produced comes from renewable sources (solar heat stored in the air and ground), and the ratio of useful heat produced to initial energy input, usually in the form of electricity, is highly efficient. In line with a growing share of renewables in electricity generation, the output of heat pumps is becoming increasingly renewable over time. When including the renewable portion of electricity in the mix, renewables account for 8.7% of global heat consumption in 2014.

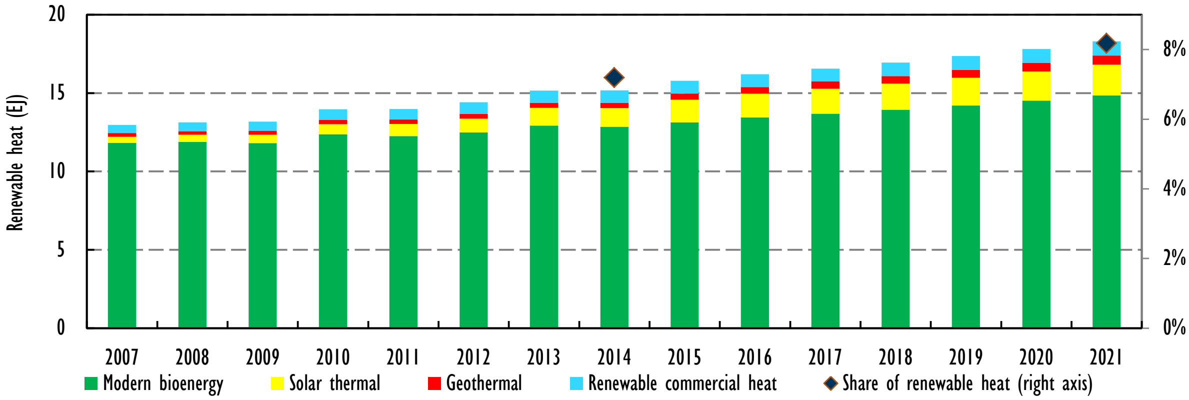
Renewable heat costs range widely, for there are many different types and scales of applications. Capital costs are often higher than for fossil fuel alternatives, but operational costs are generally lower. There are many cases where renewable heat technologies are cost-competitive with fossil fuel alternatives (e.g. solar thermal systems in hot climates, wood pellet boilers in Austria and Scandinavia). Investment costs for renewable heat systems vary over a large range depending on the technology type, level of technological sophistication and location. In addition, economies of scale are evident for commercial and industrial systems, for example for large biomass boilers or solar thermal systems.

Focusing on the residential market, an approximate global range for wood pellet boiler and stove systems would be from as low as 100 United States dollars (USD) per kilowatt thermal capacity (kW_{th}) up to USD 1 500/kW_{th}. Pellet stoves are towards the lower end of the range, with 10 kW_{th} systems available for USD 100/kW_{th} to USD 200/kW_{th}. Biomass pellet boilers with automatic fuel supply from bulk fuel storage can cost USD 300/kW_{th} to USD 1 000/kW_{th}, fully installed, for a 20 kW system. Solar thermal systems for small domestic water heating have an even larger range. They can be as low as USD 175/kW_{th} for a simple thermosiphon system in the south of Turkey to as high as USD 2 794/kW_{th} for a more complex pumped system in more northern climates such as Paris (Mauthner, Weiss, and Spörk-Dür, 2016).

Global renewable heat trends and outlook

The use of modern renewables for heat has been increasing, but more slowly than renewable electricity. Over 2007-14, modern renewable heat use increased by 17% or at an annual average growth rate of 2.3% per year, from 13.0 EJ to 15.2 EJ (Figure 4.2). The growth was less than for renewable electricity supply, which grew at around 6% per year, reaching 5 413 terawatt-hours (TWh) (19.6 EJ) in 2014. This is because in most countries, renewable energy policies have primarily focused on the electricity sector, and there are numerous barriers to the uptake of renewable heat technologies.

Figure 4.2 Global final renewable heat consumption (excluding traditional biomass), (2007-21)



Sources: IEA (2016a), *World Energy Statistics and Balances 2016*, www.iea.org/statistics/; IEA (forthcoming), *World Energy Outlook 2016*.

In 2014, almost 95% of renewables for heat was in the form of direct use of bioenergy, solar thermal, or geothermal energy in the buildings or industry sector (Table 4.1). The remaining 5% was from the contribution of renewables to commercial heat (i.e. district heating). Bioenergy dominated the direct use of renewable heat, accounting for almost 90%, while solar thermal provided another 8%. In 2015, solar thermal capacity is estimated to have reached 436 gigawatts thermal capacity (GW_{th}), almost double the capacity of solar photovoltaic (PV) (225 gigawatts electrical capacity). However, many markets have seen a contraction in recent years. Geothermal currently plays only a very small role, providing 0.3 EJ or 2% of renewable heat.

Over the medium term, growth in renewable heat is expected at a slightly higher rate, with an annual average growth rate of 2.7%. In terms of volume, most of this increase should come from bioenergy, although its annual average growth rate is anticipated to be lower than that of solar and geothermal. As heat demand also increases, the share of renewables in overall heat demand would be only slightly higher than 2014, with a projected 8.2 % share by 2021. In addition, as the use of electricity for heat is also expected to grow, and with a growing proportion of electricity supplied from renewables, the indirect contribution from renewables through electricity for heat increases by 43%. The combined share of renewable heat and renewable electricity for heat reaches around 10% of total heat demand in 2021.

Table 4.1 Global trends and outlook for renewable heat

	2014 (EJ)	Share in total	Growth 2007-14	Growth 2014-21	CAAGR 2014-21
Total energy consumption for heat	212	n/a	n/a	6%	0.8%
Total modern renewables for heat (excluding electricity)	15.2	7.2%	17%	21%	2.7%
Of which: commercial heat	0.8	5.3%	54%	13%	1.7%
Of which: direct use	14.4	94.7%	15%	21%	2.8%
Modern bioenergy	12.8	89%	9%	16%	2.1%
Solar thermal	1.2	8%	213%	65%	7.4%
Geothermal	0.3	2%	34%	75%	8.4%
Renewable electricity for heat	3.1	1.5%	n/a	43%	5.2%

Note: All figures for heat correspond to final energy consumption in the buildings and industry sector. Figures for electricity use for heat in 2014 have been estimated. The shares of modern bioenergy, solar thermal, and geothermal refer to their share in the direct use only, excluding renewable commercial heat. CAAGR = compound annual average growth rate.

Sources: IEA (2016a), *World Energy Statistics and Balances 2016*, www.iea.org/statistics/; IEA (forthcoming), *World Energy Outlook 2016*.

Meeting the objective of the COP21 global climate agreement to hold the increase in global average temperature to well below 2°C will require a decarbonisation pathway for the buildings and industry sectors that includes accelerated development and deployment of cost-effective low-carbon heating technologies. It is still too early to fully assess the impact of COP21 on the outlook for renewable heat. However, global initiatives such as the Global Alliance on Buildings and Construction and the United Nations Environment Programme's Global District Energy in Cities Initiative have the potential to stimulate further uptake of renewable heating solutions. Some countries mentioned specific targets for solar heating systems in their Intended Nationally Determined Contributions (INDCs) submitted ahead of COP21. Moving forward it can be anticipated that the overall emissions reduction commitments made at COP21 are likely to stimulate further strengthening of policy support for renewable heating technologies.

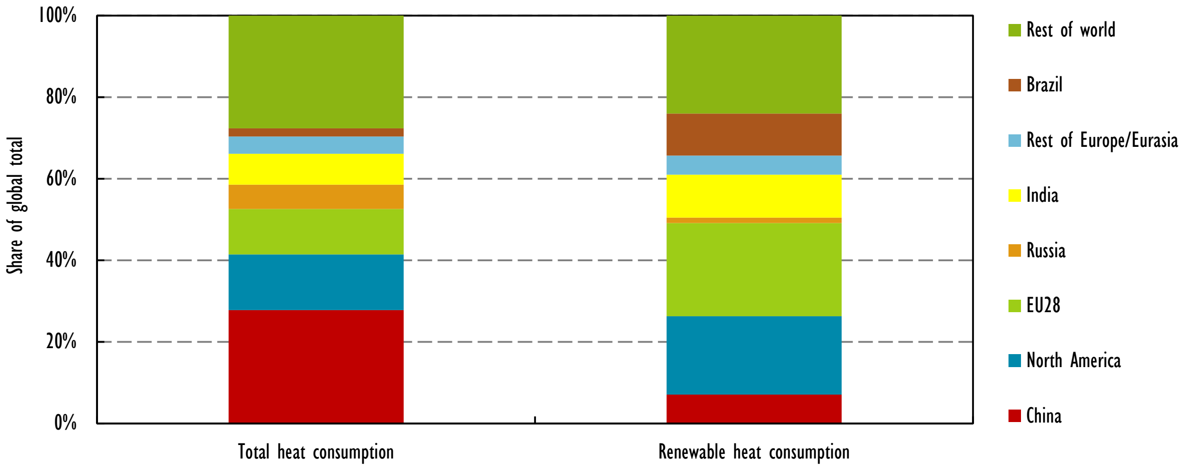
This report does not consider an accelerated case projection in the medium-term, six-year frame of this report. As discussed within this chapter, renewable heat deployment encounters numerous economic and non-economic obstacles. Many, such as slow renovation rates in buildings and slow equipment turnover in industry, are difficult to address over the medium term. Furthermore, data availability for renewable heat is incomplete and subject to higher levels of uncertainty than data for electricity and transport fuels.

Trends and outlook in key markets

More than two-thirds of the world's heat demand is in China, India, North America, Europe, Eurasia and the Russian Federation (hereafter "Russia") (Figure 4.3). The world's largest heat consumer is China, which accounts for 28% of the global total. However, the picture looks different for renewable heat, where the European Union is the biggest consumer, followed by North America. The expected

21% growth in renewable heat use in the medium term is likely to primarily come from China (one-third of the growth), the EU28, North America and India as shown later in Figure 4.4.

Figure 4.3 Final energy consumption for heat by country/region, (2014)



Source: IEA (2016a), *World Energy Statistics and Balances 2016*, www.iea.org/statistics/.

China currently has the lowest contribution of renewables to heat consumption among the large heat-consuming countries, with 1.1 EJ contributing 1.8% to heat demand, although this may be underestimated.[3] However, this is expected to almost double to 2.1 EJ by 2021, a faster growth rate than elsewhere. With two-thirds of China's heat use in industry, this low share partially reflects the more difficult situation in replacing fossil fuels with renewable heat in industry compared with buildings, for reasons of cost or technical feasibility. However, there is more potential for renewable heat in industry in the future. China also has good potential for the use of renewable heat in the rapidly growing district heating market. The country has seen a rapid increase in solar thermal use for domestic water heating in recent years, with a 370% increase between 2007 and 2014. This is expected to slow to 48% between 2014 and 2021, partially due to the increasing popularity of electric water heaters (which are seen as a more convenient option as income levels rise), as well as a slowdown in the construction market affecting installation rates in new-build properties.

The European Union is the largest producer of renewable heat globally and in 2014 produced 3.5 EJ or 23% of the world's renewable heat. Renewables provide almost 15% of the European Union's heat demand, primarily in buildings, which account for 61% of heat use in the region. In the European Union, deployment of renewable heat is driven by the 2020 targets under the RED, which includes renewable heating and cooling. In the medium term, EU28 renewable heat use is expected to increase by 17% to 4.0 EJ by 2021,[4] and the share of renewable heat to 17%.

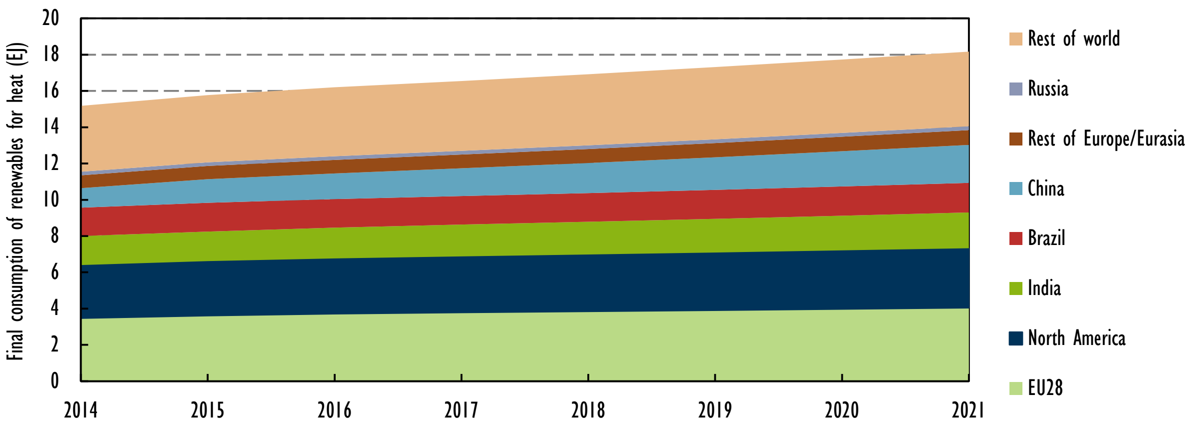
In **North America**, renewables provided 2.9 EJ (10% of heat demand) in 2014, with a higher share in industry (14%) than in buildings (8%). In Canada, the industrial share is particularly high (22%), most

[3] China does not report the use of bioenergy for heat in industry. Given its significant pulp and paper industry, it is likely that biomass residues are used for heat, but not reported in official statistics submitted to the IEA.

[4] As discussed above, these figures do not include heat pumps, but they are counted in the European Union's compliance with the RED.

of which is bioenergy, primarily residues from the pulp and paper industry. The use of renewable heat in North America is expected to grow by 11% to 3.3 EJ by 2021, almost entirely due to growth in solar thermal in both Mexico and the United States. In the case of the United States, the extension of federal tax credits to 2021 is expected to drive the expansion, whereas in Mexico, continued solar thermal investment is expected to come from incentives such as accelerated depreciation for tax purposes and low-interest loans.

Figure 4.4 Final consumption of renewables for heat by country/region, (2014-21)



Source: IEA (2016a), *World Energy Statistics and Balances 2016*, www.iea.org/statistics/; IEA (forthcoming), *World Energy Outlook 2016*.

Brazil has one of the highest shares of renewable heat use among the countries and regions covered in this section, with 37% of its heat demand met by modern renewables, providing just under 1.6 EJ in 2014. Around 68% of Brazil's heat demand is in industry, and renewable heat is mainly used in the food and tobacco industries, as well as pulp and paper production and through sugar cane bagasse use in the sugar and ethanol industry. There is also some inefficient use of charcoal in the iron and steel industry. With a relatively high share of renewable heat in Brazil already, growth prospects are relatively low, with an increase of only 4% to just over 1.6 EJ expected over 2014-21.

Half of **India's** heat demand is in the industry sector, and 10% of overall heat requirements were met by modern renewables in 2014, providing 1.6 EJ. Renewable heat is expected to increase by 23% to 2 EJ by 2021, with growth mainly in industrial bioenergy use. India ranks as one of the largest countries using bioenergy in the industrial sector including the use of bagasse, rice husk, straw and cotton stalks. India also ranked fourth globally for new solar thermal installations in 2015 with approximately 826 megawatts thermal capacity (MW_{th}) of capacity installed. However, suspension of the country's national grant scheme in 2014 has resulted in discussions between the government and the solar thermal industry in early 2016 on the adoption of new support schemes.

Russia has a high heat demand (6% of the global total) both in buildings and industry, but renewable heat provided under 2% of Russian heat demand (0.2 EJ) in 2014. Neither overall heat demand nor renewable heat production is expected to see much change in the medium term. Therefore, the country's renewable heat potential will remain mainly untapped due to an absence of policy drivers, such as renewable heat policies or low-carbon policies.

The impacts of lower crude oil prices on residential renewable heat deployment

The impact of the reduction in crude oil prices since mid-2014 also extends to the heating sector. Generally, the most promising opportunities for the deployment of renewable heating technologies are found where conventional heating fuels are most expensive. In the residential sector, this is often in areas without access to the natural gas grid, as natural gas is generally cheaper per kilowatt-hour (kWh) than other fossil alternatives such as heating oil and LPG. This is demonstrated by the United Kingdom's (UK's) domestic Renewable Heat Incentive (RHI) scheme where 72% of heat pump and 82% of bioenergy installations have been off the natural gas grid (BEIS, 2016b).[5]

The exact nature of competition between fossil fuel and renewable heating systems varies. In some cases a direct purchasing decision between a renewable or fossil fuel heating system to supply all heat demand is required, e.g. for a residential heat pump system[6] or biomass boiler. In other cases systems can work in tandem, for example solar thermal systems, sanitary water heat pumps and wood pellet stoves can complement fossil fuel systems. In either case cheaper fossil heating fuels can affect the attractiveness of investment in a renewable heating system due to lower operational cost savings. However, with dual or hybrid systems, the prospect of fuel switching after installation can also occur, with the impact of changes in the relative competiveness of heating fuels also dependent on the contribution of each to total heat demand.

Generally, the strongest price competition for renewable heating technologies comes from oil and gas boilers. These fossil fuel heating technologies have become relatively more attractive as heating oil and natural gas fuel prices dropped in many markets in 2015. This was due to their closely linked relationship with global crude oil prices, which decreased by roughly 70% over the last two years, dropping from USD 100 per barrel (bbl) in the first half of 2014 to as low as around USD 30/bbl in early 2016. The largest impact from this is the reduction in operating costs for oil-boiler systems with annual average residential heating oil prices dropping 33% from 2014 to 2015 in member countries of the OECD. As a result, in many countries, and particularly in Europe, during the current period of low oil prices, renewable heat technologies must compete not only with natural gas where access to a supply is available, but also heating oil in areas off the natural gas grid that are key areas for market growth. The impact on household natural gas costs has been weaker in most OECD countries. In 2015, annual average OECD household natural gas costs declined 18% y-o-y.[7]

Due to higher initial investment costs for some renewable heating technologies,[8] their economic attractiveness versus fossil fuel heating depends on the ability to offer lower operational costs to pay back the initial investment. A combination of higher investment costs and reduced operational cost savings due to lower fossil heating fuel prices results in longer payback periods and challenges the economic case for investing in renewable heating solutions in some cases. However, it should be noted that in the residential sector, investment decision making is not solely based on cost

[5] Data from April 2014 to August 2016. Aside from cost considerations, these technologies naturally have higher installation rates outside of densely packed urban areas as a higher share of the housing stock has suitable space to install for example a bioenergy system or ground loops for a GSHP.

[6] Some residential heat pump systems also have integrated electric immersion heaters.

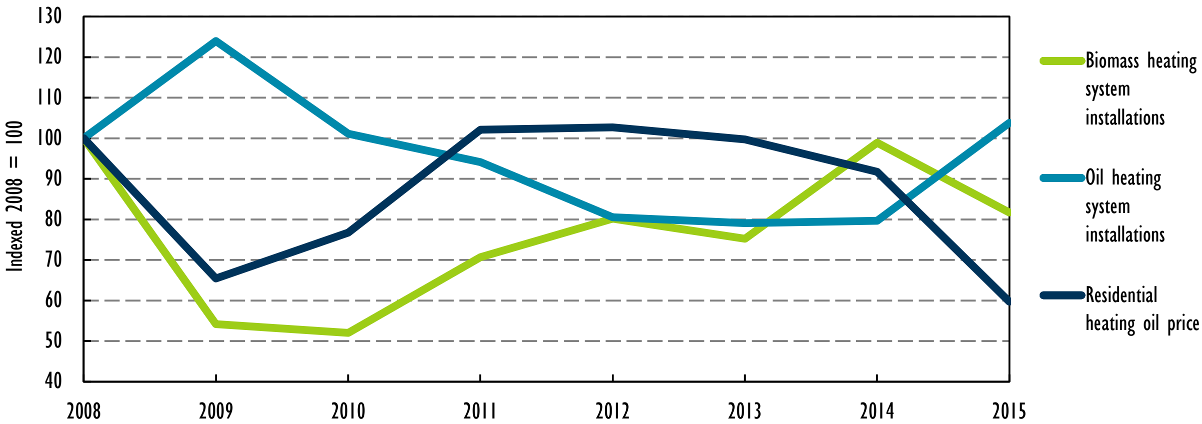
[7] The United States was an exception as y-o-y household natural gas prices fell 33% while household heating oil decreased 30%.

[8] Higher initial investment costs can be due to the larger size and engineering complexity of biomass heating systems and cost of ground loops and low-temperature heat distribution systems for GSHP technologies.

optimisation. Other factors such as building tenure, whether the building is new or existing, and familiarity with certain technologies also come into play.

There are indications that sales of biomass pellet boiler and stove systems have been impacted by lower heating oil and natural gas prices. In Austria, France and Italy, sales of wood pellet boilers dropped in 2015 (Gauthier, 2016). In Germany, there is a clear correlation between consumer purchase choices regarding oil heating systems and reduced heating oil prices, and a consequential impact on the uptake of biomass systems as shown in Figure 4.5. Increased attractiveness of oil boiler systems is also mirrored in the United Kingdom, where 2015 saw an almost 10% increase in domestic oil boiler purchases. However, in both these cases it should be noted that oil boilers only account for a relatively small segment of the overall heating systems market, as in both Germany and the United Kingdom natural gas systems are most common. In Europe, sales of pellet stoves, which have lower investment costs than boilers, fell by just under 10% y-o-y in 2015 (Argus Media, 2016). The largest reduction in pellet stove sales was observed in Italy, where a 20% drop in sales occurred linked to lower heating oil and natural gas prices. However, the Italian market was still robust with around 200 000 pellet stoves sold in 2015.

Figure 4.5 Residential heating oil price compared with biomass and heating oil system installations in Germany (2008-15, indexed)



Sources: IEA (2016c), *IEA Energy Prices and Taxes* (database), www.iea.org/statistics/; BDH (2016), *Marktentwicklung Wärmeerzeuger 2005-2015, www.bdh-koeln.de/fileadmin/user_upload/pressemitteilungen_pdf/Marktentwicklung_Waermeerzeuger_2005-2015.pdf.*

Pellet stove sales in France during 2015 were around 100 000, representing 20% y-o-y growth (Gauthier, 2016), while in Spain sales are also on an upward trend despite lower fossil fuel prices. The resiliency of these particular markets for pellet stoves highlights that the impacts of lower fossil heating prices are market-specific and these are not the only factor influencing market prospects. For example in France, key factors to explain ongoing wood pellet consumption growth relate to increased fuel availability, improved fuel delivery services, the fact that wood pellet prices will not be liable for carbon taxation via the climate energy contribution, and the long-term price stability of wood pellets compared with fossil heating fuels.

A reduction in the relative competitiveness of heat pumps compared with oil boilers is evident. As most residential heat pump systems are electrically driven, the larger reduction in household heating oil prices relative to electricity in 2015 has impacted heat pump operational costs relative to oil boilers.

While the operational costs of heat pumps relative to oil boilers are different within each country, there was a general reduction in their relative competitiveness across the OECD in 2015. The average reduction in annual household electricity prices in OECD Europe was just 14% compared with 34% for heating oil, while in the United States and Canada household electricity prices increased y-o-y in 2015 compared with reductions of 30% and 27% respectively for heating oil. In addition, electricity costs have increased in some countries as a result of levies to cover the cost of the transition to higher shares of renewable electricity. However, such a transition also increases the emissions reduction potential of heat pumps.

Irrespective of these changes in relative fuel costs, at 2015 electricity prices, a well-specified and -installed GSHP system can deliver competitive operational costs compared with oil boilers. However, the overall attractiveness of installing such systems must also take into account the relative initial investment costs of the heat pump system compared with alternatives, as well as non-economic factors. In such assessments heat pumps are more competitive in new-build properties. There are indications of lower y-o-y growth in GSHP system installations in 2015 compared with 2014 in several European markets, notably Finland and Germany. However, it is harder to link these to fossil fuel prices due to a longer trend of slowing annual market growth rates in Europe.

The impact of fossil fuel prices on solar thermal installations is more difficult to assess given the variety of systems used for a range of heat applications. Depending on the climate and application, solar thermal installations may meet all or only a portion of the heat demand, requiring a backup system that may or may not run on fossil fuels. These dynamics make it difficult to assess the impact of lower fossil prices on the attractiveness of solar thermal in general. New solar thermal installations for domestic hot water and space heating have fallen in many European markets, due to decreasing economic attractiveness relative to conventional heating systems and even other renewable technologies.

Even in the presence of policy support schemes, total annual solar thermal installations declined y-o-y in Germany (-12%), Italy (-14%), the United Kingdom (-33%) and France (-33%). However, an increasing trend of larger solar thermal systems replacing fossil fuel boilers is evident in process heat applications, where there are high heat demands in sunny areas. Where located in high insolation areas, solar thermal installations for preheating or boiling water, drying, evaporation, and other low- to medium-temperature applications in the food, beverage and textile industries, can be more cost-effective than meeting 100% of the heat demand from diesel, LPG or gas-fired boilers alone.

IEA analysis indicates that there will be no significant oil price recovery in the immediate future, with the market potentially rebalancing at USD 80/bbl in 2020 (IEA, 2015). Therefore, the consequential lowering of fossil heating fuel prices due to low oil prices is likely to provide increased competition for renewable heating technologies for the majority of the medium term. The particularly strong reduction in heating oil costs, which resulted in increased sales of oil boilers in some markets during 2015, provides additional competition within the market segment off the natural gas grid, which is a key area of market growth for bioenergy and heat pump installations.

While fossil heating fuel price competition is undoubtedly stronger, resulting market impacts are harder to define. Lower-cost fossil heating fuels appear to be linked to y-o-y reductions for biomass boiler, and to a lesser extent stove, installations in some countries in 2015. However, this is not universal and some markets have experienced growth. In addition, adverse effects on solar thermal and

GSHP market trends are hard to identify. Furthermore, it should be noted that apart from lower fossil heating fuel prices, other factors influence the uptake of renewable heat technologies relative to fossil fuel alternatives. These include policy developments, e.g. in financial incentive programmes for renewable technologies, and initiatives such as boiler scrappage schemes. However, given higher initial investment costs for some renewable heating technologies, lower operational cost savings versus fossil heating fuels does affect investment cases and may heighten the need for adequate policy support measures to improve medium-term renewable heat technology growth prospects.

Outlook for renewable heat technologies

Renewable heat deployment for most technologies is focused on a limited number of countries and markets, which are often local or regional. While, as discussed, global heat statistics and deployment figures are subject to high levels of uncertainty, somewhat better data are available for specific technologies and for some countries. However, the data are still generally not comprehensive enough to provide detailed outlooks, such as those produced for renewable electricity and biofuel markets.

In this section, we discuss current trends and the outlook for four renewable heat technologies: bioenergy, solar thermal, geothermal and GSHPs. For each technology, the section provides a global overview and discusses drivers, challenges and costs. It then focuses on a limited number of markets with different characteristics: large markets (e.g. China for solar thermal), small but growing markets (e.g. Germany for geothermal) and stagnant markets (e.g. GSHPs in some European markets).

Bioenergy for heat

Biomass fuels can be used for heating across the buildings and industry sectors through employing a range of technologies. However, while other fuels and technologies are touched upon, the key focus of this section is biomass for wood pellet-fuelled residential heating markets.

Drivers and challenges

The drivers and challenges to growth for modern bioenergy use for heat vary by country and also sector. A non-exhaustive general overview is provided in Table 4.2 below.

Table 4.2 Biomass heating market expansion drivers and challenges

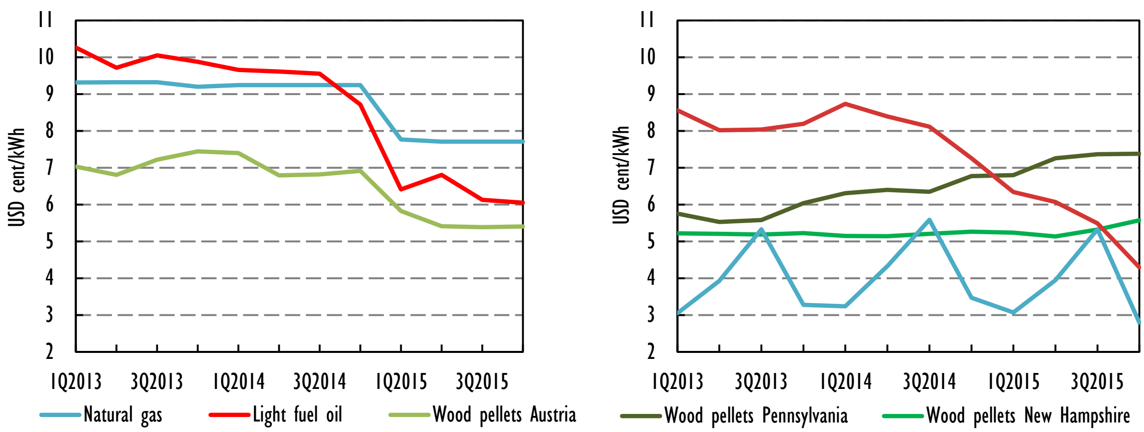
Drivers	Challenges
Growth of wood pellet markets with increasing pellet production, development of recognised fuel standards and new market mechanisms to manage price risk.	Fuel resource availability in certain countries, leading to requirements to import. Local supply chain development required in some markets to ensure security of supply.
The potential for bioenergy and waste fuel use within new and existing district heating infrastructure.	Larger space requirements than fossil fuel alternatives, especially when considering fuel storage.
Sophisticated modern biomass systems offering comparable ease of use with fossil fuel systems.	Manual fuelling and de-ashing for less sophisticated systems.
The relative long-term stability of wood pellet fuel costs compared with cyclical fossil fuel prices.	Current low costs for heating oil, which challenge competiveness in the off-gas grid market segment.
Requirements to decarbonise the heating sector leading to a range of financial incentives for biomass heating systems, e.g. tax incentives, grants and feed-in tariffs (FITs).	Low/no-cost traditional biomass availability, particularly in developing countries and emerging economies.

Cost analysis

As in the power sector, investment costs for biomass heating systems vary over a large range depending on the technology type (e.g. biomass boiler, stove, biogas plant), fuel (e.g. woodchip or pellet) and location. In addition, system capacity is also a key factor, with the potential for economies of scale evident for commercial and industrial systems.[9] Focusing on the residential market, an approximate global range for wood pellet boiler and stove systems would be from as low as USD 100/kW_{th} up to USD 1 500/kW_{th}. Pellet stoves are towards the lower end of the range, with 10 kW_{th} systems available for USD 100/kW_{th} to USD 200/kW_{th}. The level of system sophistication influences pellet boiler costs. High-quality systems with automatic fuel supply from bulk storage, which are typical in countries with high heat demand such as Austria, France and Germany, can cost USD 300/kW_{th} to USD 1 000/kW_{th}[10].

Due to their larger size and engineering complexity, biomass boiler systems generally have higher investment costs compared with fossil fuel domestic heating systems. Therefore, lower running costs are essential to ensuring their attractiveness. Globally, heating wood pellet costs are broadly consistent. In Europe, residential consumer pellet prices in Austria and Germany over 2011-15 were in the range of USD 0.05/kWh to USD 0.065/kWh and in Sweden USD 0.06/kWh to USD 0.07/kWh, compared with costs in the United States of USD 0.055/kWh to USD 0.074/kWh in the state of Pennsylvania and USD 0.05/kWh to USD 0.055/kWh in New Hampshire (both 2013-15)[11] (F.O. Lichts, 2016). The competitiveness of wood pellets for residential heating is also improved by reduced value-added tax (VAT) rates in markets such as Austria, Germany and Belgium. In the residential sector, pellet prices are influenced to varying degrees by quantity supplied, with the purchase of bagged pellets in low quantities more expensive than bulk purchase or energy service company (ESCO) heat provision in almost all markets.

Figure 4.6 Residential heating fuel costs, (2013-15), in Austria (left) and the United States (right)



Note: residential natural gas prices are for the United States and not specific to Pennsylvania or New Hampshire.

Sources: IEA (2016c), *IEA Energy Prices and Taxes* (database), www.iea.org/statistics/; F.O. Lichts (2016), *F.O. Lichts Interactive Data* (database), www.agra-net.com/agra/world-ethanol-and-biofuels-report/ (subscription service).

[9] It should be noted that economies of scale do not always directly correlate with system capacity.

[10] Costs including installation and fuel storage costs.

[11] All pellet costs per kilowatt-hour determined on the basis of an assumed calorific value of 17.5 megajoules per kilogramme.

The price stability of wood pellets provides a degree of certainty over future fuel costs over the operational life of a heating system. The price variability of pellets[12] over 2011-15 was around USD 0.003/kWh in Austria and Sweden, USD 0.0036/kWh in Germany, and as low as USD 0.0012/kWh in New Hampshire. Heating oil costs are closely aligned with crude oil prices and therefore should vary more significantly than wood pellets over the duration of a heating system investment. In Austria, the variability[13] of heating oil prices per kilowatt-hour was three times greater than that of wood pellets over 2011-15.

The attractiveness of biomass heating systems within residential and commercial buildings and the industry sector is aided by a range of policy support mechanisms. Investment grants, soft loans and tax incentives (either on a national or regional level) are available in Austria, Belgium, Bulgaria, the Czech Republic, France, Germany, Japan, Korea, the Netherlands Poland, and Spain among others. Support is additionally available in a further number of countries for biomass co-generation plants. Generation-based subsidisation for biomass heating systems is available in Italy and the United Kingdom (AEBIOM, 2015a). There is currently little support for bioenergy heat technologies in emerging economies and developing countries.

Process residues and agricultural residues offer low-cost biomass fuel supplies to the industry sector. When produced on site, process residues (e.g. in the pulp and paper industry) can represent a no-cost fuel source. Agricultural residues such as straw, corn stover and sugar cane bagasse are used in a wide variety of markets for energy purposes, such as electricity, co-generation and the production of advanced biofuels. Agricultural residue costs vary significantly by crop and location, for example linked to the manner of collection and labour costs, means of contracting, and the point of collection. Straw costs in Europe are variable depending on location, for example around USD 65 per tonne (t) to USD 90/t in Northern Europe and USD 33/t to USD 55/t in Southeastern Europe (Harrison et al., 2014). In the United States, the US Department of Energy has assessed that there is significant availability of agricultural residues, such as corn stover, accessible at less than USD 70/dry tonne (US DOE, 2016c). Sugar cane bagasse in Brazil has generally even more competitive costs, which can be below USD 50/dry tonne.

Global overview

Globally, modern bioenergy use for heat, i.e. excluding the traditional use of biomass, was 12.8 EJ in 2014. Over 2014-21, consumption of modern bioenergy in the heating sector is anticipated to grow at an annual average growth rate of just over 2% to reach just under 15 EJ. Modern bioenergy consumption in industry accounted for almost two-thirds of all modern bioenergy use in 2014, and should undergo the largest increase (+17%) over the medium term, reaching around 9.5 EJ, while modern bioenergy use in buildings is expected to grow by 0.5 EJ and reach around 5 EJ.

Modern bioenergy is the largest contributor to overall modern renewable energy use for heat globally, accounting for 89%[14] of renewable heat consumed in 2014. Despite faster growth rates from the

[12] Variability determined by the standard deviation of cost data for the time period previously outlined for each country. It should be noted, however, that wood pellet pricing is also related to the balance of supply and demand.

[13] Determined via the standard deviation of prices for both fuels over 2011-15.

[14] Figure excludes commercial renewable heat.

smaller contributions of solar thermal and geothermal sources, this is not expected to change significantly, dropping slightly to 85% by 2021. The European Union and the United States accounted for 38% of global modern bioenergy use in 2014. However, over 2014-21 China, India and Africa are expected to account for around 50% (1 EJ) of the expected growth, primarily driven by industry and, to a lesser degree, the transition from traditional to modern bioenergy use in the buildings sector.

Overview of selected markets

In the Baltic States**,** strong security of supply drivers, particularly gas import dependence, combined with excellent biomass forestry resources, existing district heating infrastructure and the price competitiveness of pellets versus fossil fuels have resulted in strong development of biomass heating, with consumption on an increasing trend in all three countries. In addition, forestry growth exceeds felling in each, facilitating sustainable supply.

In **Lithuania**, deployment of bioenergy in district heating started to accelerate in the wake of gas price increases in 2011. Over the 2012-15 period, in which biomass-fuelled capacity serving district heating tripled, the euro (EUR) per megawatt-hour heating price for district heating declined by around 25% (Masiulis, 2016). The share of biomass consumption within district heating passed 60% in 2015, with the remainder mostly provided by imported natural gas. Biomass-fuelled heating plants connected to district heating networks reached around 1.5 GW_{th} in 2015, increasing 380 MW_{th} y-o-y (Masiulis, 2016).

Lithuania has a target to increase the share of biomass consumption within district heating to 70% by 2020 (Rasburskis, 2016). Progress towards this should be boosted by the commissioning of a >200 MW_{th} high-efficiency biomass and waste co-generation plant in Vilnius, planned for 2018. District heating accounts for approximately 90% of heating in the city, and the project should provide approximately half of demand and offset the majority of natural gas consumption during the heating season (Rasburskis, 2016). There is a focus in the country on the modernisation of fossil fuel-fired boilers, with loan and grant funding available for the conversion of heating plants to biomass.

In the part of the residential sector that is not connected to district heating, bioenergy is also prevalent, with around 80% of households using biomass for heating purposes. However, this is mainly in the form of log burners, and there is significant scope for higher-efficiency modern biomass pellet and woodchip systems. Biomass accounts for around a third of industrial heat consumption and is mainly used to serve low- and medium-temperature heat loads in the food and drink and tobacco industries. Bioenergy capacity is currently around 300 MW_{th}, with the aim to reach >500 MW_{th} by 2020.

Lithuania introduced the innovative Baltpool Exchange in 2013, matching biomass suppliers and consumers for physical delivery contracts covering different classifications of woodchips and pellets and contract length (e.g. week, quarter, six-monthly). As of 2016, regulated energy producers (e.g. publicly owned district heating networks) will be obliged to procure all supply through the exchange. However, it is also used by non-obligated consumers and accounted for 64% of all trade in 2015 (Zalaite, 2016). The exchange has improved the liquidity of biomass supply, resulting in multiple benefits such as:

- Facilitating market entry of new participants. For example, from comparing the January to June period in 2014 and 2016, the average monthly market share of the largest supplier dropped from just under 40% to 23%.
- Transparency and competitiveness in pricing. For example, during the 2015-16 heating season, average prices fell by 20-39% across different districts (Masiulis, 2016).[15]
- Reducing the risk of supplier non-delivery through conducting supplier checks and linking permitted supply volumes to risk categorisation.

Estonia also has significant district heating infrastructure, which provided 70% of total heat in 2015. Biomass was the most prominent fuel used in district heating, accounting for 45% of supply. Ensuring security of supply and the promotion of domestic fuel production are key elements of the country's National Energy Development Plan for 2030 and beyond (Meeliste, 2016). Financial support to the heat sector is made available based on the strategic plans for local heat consumption, with actions carried out under these plans publicly financed. To ensure that projects meet energy efficiency, environmental sustainability and financial requirements, adherence to strategic plans is a precondition to applications for financial support for the construction and renovation of heating installations. Support is also available for the construction and renovation of biomass co-generation plants and reconstruction of boiler houses to accommodate renewable technologies. Nearly 60% of **Latvia's** land area is covered by forest, and the country is the largest pellet producer in the Baltic States, and third-largest in the EU28 in 2014. Latvia's annual forestry felling volumes are more than five times greater than domestic biomass consumption on a per capita basis, while both woodchip and pellet heating fuels are competitive in relation to fossil fuels.

In **the United States**, an expansion of pellet heating markets over the medium term can be expected. Biomass consumption in the residential sector is primarily via heating stoves fuelled by log wood, although pellet consumption is increasing (US EIA, 2014). Given competitive gas prices, biomass systems are most attractive in the Northeast of the country, where around 80% of households utilise heating oil (US DOE, 2016a). This could especially be the case within Massachusetts and New Hampshire, where biomass heating systems are included within state Renewable Portfolio Standards (RPS). However, growth potential is likely to be constrained while heating oil and LPG prices remain low. Based on data from the US Energy Information Administration (US EIA, 2016), wood energy consumed in the residential sector in 2015 dropped by around one-quarter y-o-y, with lower fossil fuel prices and a relatively milder winter climate considered to be contributing factors. In New York City, a 2% biodiesel mandate is in place for heating oil used in the residential and commercial sectors. In addition, in New York State, blended heating oil consumption in the residential sector is supported by an income tax credit of USD 0.01/gallon for each percentage point of biodiesel blended with conventional heating oil, up to USD 0.20/gallon (US DOE, 2016b).

As of 2013, biomass heating was used in more than 3 million households in **Canada**[16] (Bradburn, 2014). Growth potential for biomass heating is limited in areas with access to natural gas supply. This includes the majority of the population of British Columbia, Alberta, Saskatchewan and Manitoba.

[15] Greater equality of pricing across different regions in the country was also delivered. Furthermore, the average price paid for biomass fuels decreased both via the exchange and also for over-the-counter trades.

[16] Information on the residential wood pellet market in Canada provided via personal communication with Gordon Murray of the Wood Pellet Association of Canada.

However, growth has been strong within communities not connected to the gas grid where biomass systems are competitive with heating oil, as well as in rural areas such as the Northwest Territories (assisted via grant funding for biomass systems) and Yukon. Within these, boiler installations, storage and distribution networks have grown to support around 30 000 t of annual pellet consumption. The number of community-scale biomass heating projects has also grown, particularly in British Columbia and the Northwest Territories. As of 2013, the capacity of community heating projects ranged from <100 kW_{th} to 35 MW_{th}, with systems fuelled by wood pellets, waste wood and in some cases agricultural residues (Bradburn, 2014). Estimates of residential wood pellet consumption are between 250 000 t and 500 000 t per year (Rebiere, 2016). Growth potential appears promising in Ontario, where a significant share of the population is not connected to the gas network, the Atlantic Provinces and Quebec, where financial support is available to replace fossil fuel heating systems with biomass alternatives and a pipeline of biomass community heating projects has been established.

Wood pellets for heating market consumption, production and trade status

The status of biomass heating markets is also indicated by developments in the trade of wood pellets for heating purposes. In 2015, global consumption of wood pellets in residential and commercial buildings for heating reached 14.6 megatonnes (Mt) according to the Hawkins Wright *Outlook for Wood Pellets* (Hawkins Wright Ltd., 2016). The largest wood pellet heating markets are located in Europe where Italy, Germany, Sweden, France and Austria have developed robust modern bioenergy heating markets. Wood pellet consumption for heating purposes in Europe rose to around 11.5 Mt in 2015, an increase of over 7% from 2014 levels (Argus Media, 2016).

This increase in wood pellet consumption was achieved due to growth in system installations in both the residential sector, which currently accounts for the majority of demand, as well as commercial systems. Consumption growth occurred in Europe despite the third mild winter in a row and context of lower heating oil prices. Increased heating market demand was also the primary driver behind an increase in wood pellet production capacity. In addition to the policy support mechanisms previously outlined, market growth prospects for pellet heating in Europe are likely to be enhanced by policies, legislation and support schemes to encourage greater use of district heating. These are already in place in countries such as Denmark, Norway and the United Kingdom.

Heating wood pellet markets are generally less influenced by policy changes and subsidisation than power generation equivalents. However, growth is influenced by weather conditions and the market context for competing fuels and technologies. Weather-related uncertainty is a particular challenge for suppliers of heating wood pellets owing to the need to maintain sufficient pellet supply and logistical networks to meet heating season demand, while limiting summer storage costs. Certification plays an important role in development of the heating wood pellet market in order to assure uniform quality and higher tradability. Within European markets, ENplus certification is commonly required, and the scheme is growing, with the number of certified producers approaching 300 in 2015 (AEBIOM, 2015b). The introduction of futures contracts linked to ENplus wood pellet specifications for residential heating supply should increase the ability of suppliers to hedge price volatility.

Wood pellet consumption in Italy, France, Germany and Austria is currently almost exclusively for heating purposes. Italy is the largest wood pellet heating market in Europe and accounts for the majority of European pellet stove installations. In Italy, wood pellet consumption was around 3 Mt in 2015 (Argus Media, 2016) with the majority of pellets sourced via imports. Wood pellet imports to

Italy from the United States and Canada dropped significantly in 2015 from 2014 levels. This could be explained to varying extents by currency fluctuations, lower fossil fuel prices, milder winter weather and an increase in VAT on wood pellets from 10% to 22% in 2015, increasing the delivered price to residential consumers. VAT on wood pellets was also increased from 10% to 13% in Austria.

Deployment of biomass boilers in the United Kingdom has grown as a result of support through the RHI. Associated demand for wood pellets is now aligned with domestic production capacity, and without expansion, growing imports may be required to serve heating demand, in addition to the large quantities of wood pellets already imported to the United Kingdom for power generation. In France, pellet production capacity of approximately 2 Mt (Vial, 2016) assures self-sufficiency without the need for imports. Funding has also been put in place over 2015-16 to further develop biomass fuel supply, particularly from private forestry. European wood pellet supply is further increased by pellet production in the Baltic States, which reached around 2.75 Mt in 2015 (LATbio, 2016), and where production volumes over ten times higher than consumption allow for significant export potential.

It is challenging to isolate the impact of lower fossil fuel prices, in particular heating oil, on heating wood pellet markets since demand is also linked to weather conditions; competition from other heating technologies, e.g. heat pumps; and the policy landscape, e.g. changes to pellet VAT or the introduction of subsidy measures. As previously outlined within the *MTRMR 2016*, y-o-y reductions in residential biomass heating systems were observed in several markets in 2015. These lower sales may constrain future growth in wood pellet demand for heating purposes over the coming years.

Once domestic pellet boilers are installed, they usually act as the principal heating source with the preceding system removed. As a consequence, once a system is installed, lower pellet consumption as a result of reduced fossil fuel prices should be relatively uncommon. Pellet stoves are usually used to provide heating to a particular room or area of the home and as such can complement other forms of heating. Therefore, fuel switching could occur where fossil fuel prices become more competitive. This may be particularly relevant in Italy, the leading European pellet stove market. This could also be the case for any commercial-scale wood pellet boiler installations that have a fossil fuel backup system.

Solar thermal heating

Solar thermal technologies can produce heat for hot water, space heating and industrial processes, with systems ranging from small residential scale to very large community and industrial scale. The required temperature to meet the heat demand determines the collector type and design. Solar thermal systems can be installed either as small thermosiphon stand-alone systems or can be integrated into large-scale urban district heating networks or industrial facilities.

Approximately 91% of the solar thermal collector area in operation is used to provide domestic hot water (DHW) in the buildings sector, with 63% for small systems in residential/single-family homes (DHW-S) and 28% for larger systems in multifamily homes and commercial and public services sectors (DHW-L) (Mauthner, Weiss and Spörk-Dür, 2016). The remaining 9% of the collector area is for swimming pool heating, space heating, industrial process heat, district heating and solar cooling. However, regional differences in application exist. Small hot water systems make up over 50% of the operating capacity in China, Asia and Latin America, while large hot water systems make up the majority in the Middle East and North Africa (MENA). The application profile is more diversified in Europe, where at least 20% of the installed capacity is through combi-systems, providing both space heating and hot water. In the United States, Canada, Australia and New Zealand, the majority of the collector area in operation is used for swimming pool heating. Depending on the climate and application, solar thermal systems may meet all or only a portion of the heat demand and thus require a backup heat source. This is particularly important for space heating systems used in colder climates where heating demand increases during seasons with less sunlight. In larger systems, seasonal storage systems can be included, which makes larger solar thermal systems very cost-competitive.

Drivers and challenges

The drivers and challenges to solar thermal deployment vary by country and also by sector. A non-exhaustive general overview is provided in Table 4.3 below.

Table 4.3 Solar thermal heating drivers and challenges

Drivers	Challenges
Low-carbon source of heat to meet renewable energy national targets.	Insufficient incentive levels; intermittent support schemes tied to fluctuating annual budgets or fixed funds.
Particularly attractive in markets with high electricity prices and good insolation, and for applications where high heat demand is met by fossil consumption.	High investment costs compared with alternatives; installations can be complex; not enough qualified installers; competition from lower cost heating technologies.
Lower operations and maintenance (O&M) costs, particularly for thermosiphon systems or large-scale solar fields. Innovative business models such as leasing or ESCOs.	Lack of public awareness of solar heating and cooling technologies, confusion with solar PV technologies. Lack of system providers and business models for large-scale systems.

Cost analysis

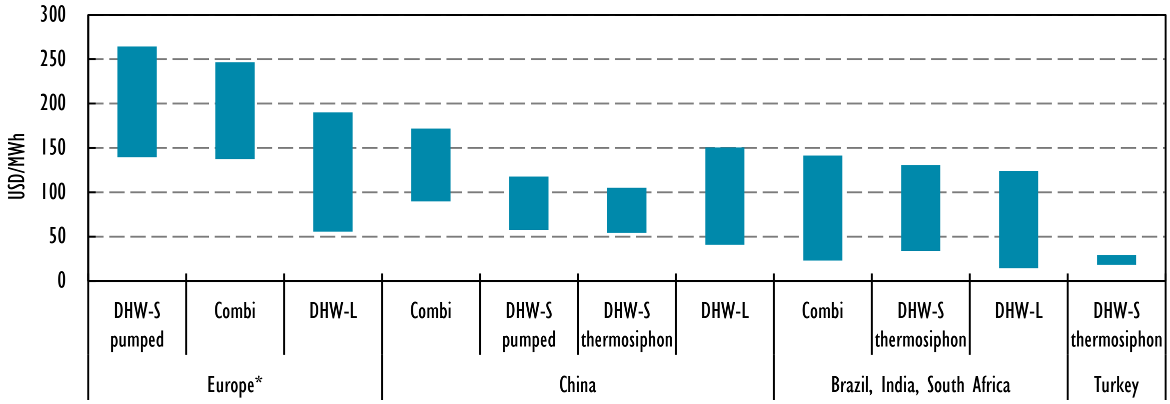
The cost analysis in this subsection will focus mostly on solar thermal applications for domestic hot water and space heating in the buildings sector. The data for this analysis were provided by the IEA Solar Heating and Cooling Technology Collaboration Programme based on a set of surveys from selected markets (Mauthner, Weiss and Spörk-Dür, 2016). The ranges provided here are based on a subset of selected countries and thus should not be considered as exhaustive but be interpreted as a sample from major solar thermal markets.

Solar thermal heating investment costs span a wide range depending on the system type and size of installation. Investment costs for the most frequent application, DHW-S, can range from USD 175/kW$_{th}$ to USD 2 794/kW$_{th}$ with closed-loop pumped systems falling at the higher end and thermosiphon systems on the lower end. Closed-loop pumped systems are used in colder climates such as some regions in Europe and North America, and operate with a heat transfer fluid in the collector to prevent freezing. These systems tend to be more expensive than thermosiphon systems because of the additional auxiliary equipment including pumps, controllers and heat exchangers. Thermosiphon systems are less complex, thus less expensive (USD 175/kW$_{th}$ to USD 1 476/ kW$_{th}$) and are commonly installed in warmer climates around the Mediterranean, Latin America, sub-Saharan Africa and MENA. In areas that rarely freeze, open-loop pumped systems protected from freezing by recirculation offer a good middle ground. Investment costs for DHW-L tend to be lower than DHW-S systems owing to economies of scale, while combi-systems are generally more expensive because of the complexity required to meet additional space-heating needs.

Installation costs can constitute a significant portion of the solar thermal investment costs. For more complex systems such as pumped DHW-S or combi-systems, the installation can account for as much as 30-40% of the investment costs in some markets. These installations often have to be customised, requiring additional mounting structures on the roof or inside the building, which drives up the cost and extends installation time. In markets with simpler thermosiphon systems and less expensive labour such as China, India and Brazil, installation costs make up a smaller share (7-20%). Cost reduction efforts are focusing on standardising equipment to minimise the customisation needed during installation.

Solar heating costs also span a wide range depending on the region and application. They depend on many factors such as investment cost, O&M, lifetime of the system, and local climatic factors such as insolation levels and ambient temperatures. For DHW-S, the costs can be as low as USD 18/MWh for a thermosiphon system in Turkey to as high as USD 264/MWh for a pumped system in Northern Europe (Figure 4.7). Heating costs tend to be lower in markets with thermosiphon systems in warmer climates and higher insolation levels, whereas the costs tend to be higher in colder climates because of the lower insolation levels and higher system costs needed to sustain performance in cold weather. The economics also depend on the percentage of a building's hot water and/or space heating needs that is met by the solar thermal system and if a backup or booster heat source is needed. Lower fossil fuel prices can challenge the economic attractiveness of solar heating, although some solar thermal systems can be very cost-effective in some cases, particularly for applications with high hot water demands in sunny areas. Very large systems (megawatt-scale) connected to district heating have also proven to be cost-effective in Denmark, particularly as a result of the use of low-cost, large-volume, seasonal heat storage systems.

Figure 4.7 Solar thermal heat production costs in the buildings sector



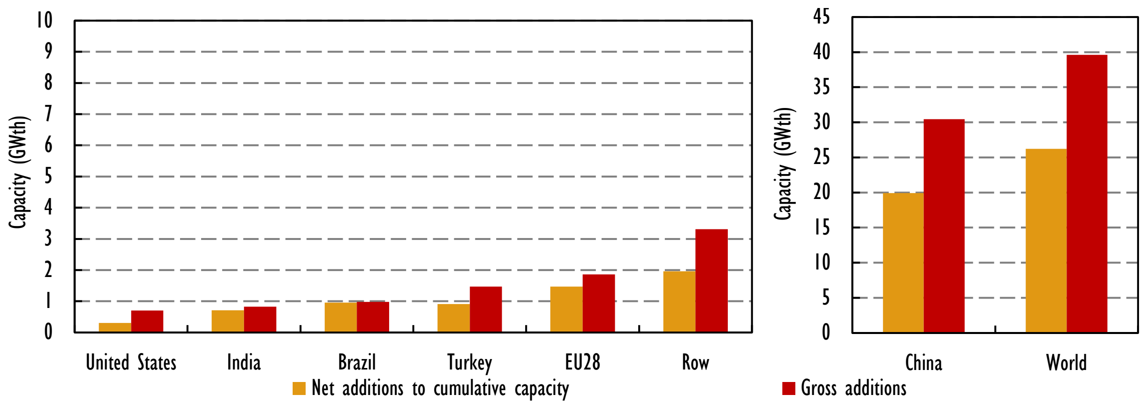
Note: *Europe excludes Turkey for the purposes of this graph only.

Source: Mauthner, Weiss and Spörk-Dür (2016), *Solar Heat Worldwide: Markets and Contribution to the Energy Supply, 2016 edition*, www.iea-shc.org/data/sites/1/publications/Solar-Heat-Worldwide-2016.pdf.

Global overview

The global solar thermal market continued to slow in 2015 for the second year in a row, as total annual installations decreased by 15% owing to a continual slowdown in China and sluggish growth in the European Union. Total investment was estimated to have declined by 13 % in 2015 as total annual installations[17] dropped to an estimated 40 GW_{th}, down from 47 GW_{th} in 2014 (Figure 4.8). Cumulative installed capacity[18] reached an estimated 436 GW_{th} by the end of 2015, implying net additions to cumulative capacity were 26 GW_{th}, 30% less than total annual installations as a result of the amount of capacity decommissioned and rate of replacement. The latter can be quite large in some cases, particularly in China, where shorter lifetimes lead to high rates of system replacements. In other cases, such as Japan, decommissioning outpaced replacements and new installations continued to drop by 8% in 2014.

Figure 4.8 Annual market growth in 2015, net and gross additions



Note: Row = rest of world.

Over 90% of the total annual deployment in 2015 was in the top ten markets: China (30.5 GW_{th}), Turkey (1.5 GW_{th}), Brazil (1.0 GW_{th}), India (0.8 GW_{th}), the United States (0.7 GW_{th}), Germany (0.6 GW_{th}), Australia (0.4 GW_{th}), Israel[19] (0.3 GW_{th}), Mexico (0.2 GW_{th}), and Poland (0.2 GW_{th}). China continued to lead the global deployment by installing roughly 77% of the capacity in 2015, although the market continued to slow, owing to a weak new housing market and the end of several incentive programmes (Figure 4.9). Meanwhile, favourable economics continued to drive the growth of unsubsidised systems in Turkey, Greece and Spain. However, their growth was unable to offset the continuing decline experienced in the EU28, which shrank by 9 % as lower fossil fuel prices and insufficient incentives challenged the economics of DWH-S in colder climates. Despite government support in many countries, total annual installations continued to fall in major markets such as Germany (-12%), Austria (-13 %), France (-33 %), and the United Kingdom (-33 %). Most other

[17] The term "total annual installations" in this report refers to newly installed systems plus replaced systems during the year. The term "new installations" will be used to refer only to systems that are installed for the first time and does not include systems that are replacing older ones. Market growth will refer to total annual installations and be discussed using this term. Figures for total annual installations are estimated based on data from several sources including IEA (2016d), Mauthner, Weiss and Spörk-Dür (2016), REN21 (2016) and Eurobserv'ER (2016).

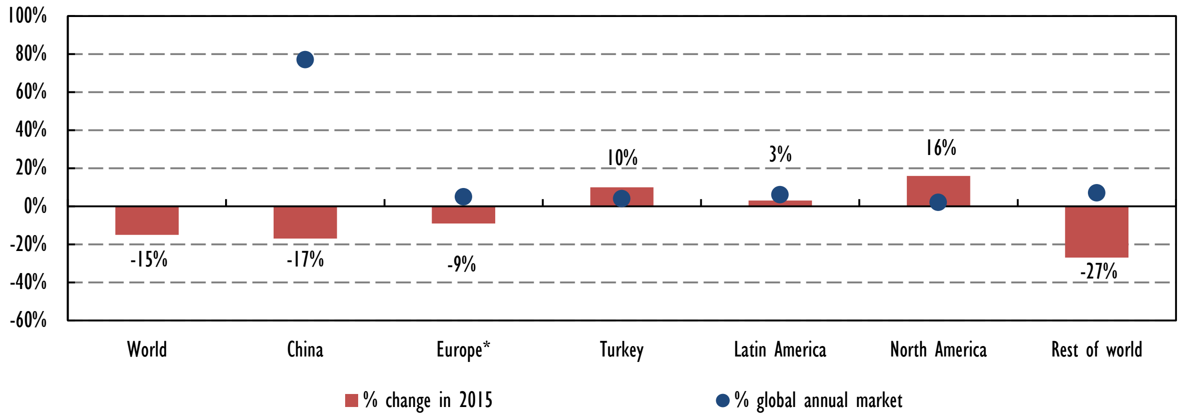
[18] The dispersed nature of solar heating installations makes monitoring cumulative installed capacity a challenge. Therefore, cumulative capacities are often estimates based on sales and assumptions about the decommissioning rate of older systems. Figures for cumulative installed capacity are estimates based on data from IEA (2016d) and Mauthner, Weiss and Spörk-Dür (2016).

[19] 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.

regional markets are also estimated to have experienced contraction in annual growth, except for North America, where Mexico drove most of the regional growth up over 16 % in 2015 compared with 2014.

The largest application for solar thermal systems remains DHW in the buildings sector. However, many markets are experiencing an increasing trend toward larger system installations, suggesting they may be experiencing more favourable economics. In 2014, almost 60% of new installations were DHW-L. Solar process heat remained marginal in 2015, accounting for 1% of total solar heat consumption with over 90% produced in Turkey and India. However, deployment is spreading to other countries. By the end of 2015, more than 30 countries had solar thermal systems installed for process heat applications such as pre-heating, water, evaporation, drying and boiling (REN21, 2016; Mauthner, Weiss and Spörk-Dür, 2016). District heating applications continued to drive the growth in Denmark, where total annual installations grew by 55%.

Figure 4.9 Annual market growth in 2015 relative to 2014 and share in global additions



*Europe excludes Turkey for the purposes of this graph.

Over the medium term, solar thermal heat consumption is expected to grow by 5% annually and reach 2 EJ by 2021, with the biggest gains in China, the United States and Europe. The buildings sector is forecast to remain the largest consumer, accounting for 97% of solar end-use heat, though consumption in the industry sector is expected to ramp up, seen growing by 15% annually over 2015-21. China leads the growth but in the absence of stronger support, deployment is expected to be significantly slower than in previous years. The extension of the federal residential tax credit to 2021 in the United States is expected to drive deployment over the medium term, particularly in states with additional incentives such as California and Hawaii. In Europe, the deployment dynamics will likely differ by the climatic regions. Mediterranean countries with higher insolation levels should continue to find lower-cost thermosiphon systems suitable for applications with low-to-medium-temperature heat demand. However, in colder climates at higher latitudes, solar heating will likely continue to require government support to make systems attractive against lower-cost heating alternatives.

One of the market segments with the largest untapped potential for solar thermal is industrial process heat, particularly in sectors with high hot water demands, such as the textile or food industries, that are currently being met by fossil fuels. Higher temperature applications in other sectors are also becoming increasingly attractive, such as steam generation for EOR (Box 4.2). Solar thermal process heat is expected to more than double by 2021, with over 60% of the expected growth in Europe, India, the United States and the Middle East. However, the pace of deployment is limited by high up-front costs associated with customised designs for existing process heat integration and a lack of innovative financing schemes.

Box 4.2 The world's largest solar process heat plant: EOR in Oman

The 1 GW_{th} Miraah solar thermal plant currently under construction in Oman represents a significant development for solar process heat applications, as it will be by far the world's largest solar thermal process plant when completed. It has been designed specifically for solar-assisted EOR. Thermal EOR is an energy-intensive process that relies on large amounts of steam produced with natural gas to maximise crude oil extraction from heavy oil fields. It is estimated that this process consumes over 1% of global gas supply, with 90 Mt per year of associated CO_2 emissions. However, an innovative "enclosed trough design" developed by GlassPoint uses solar thermal energy to produce steam at costs comparable to natural gas, provided gas prices are above USD 6 per million British thermal units (Btu). It can reduce natural gas consumption by up to 80% (GlassPoint, 2014), as demonstrated by Petroleum Development Oman's successful exploitation of a 7 MW_{th} pilot plant that has been in operation for three years.

Producing economically viable steam under Oman's harsh desert conditions is made possible by enclosing parabolic troughs within a greenhouse. This protects the concentrating collectors from high winds, sand and dust. Automated washing and filtration systems keep moisture and dust out, as well as reducing cleaning costs. The design allows for direct steam generation by using unusually light parabolic trough mirrors rotating around fixed heat collecting pipes and integrates seamlessly into existing EOR systems.

Miraah will start operations in 2017 and steam production will gradually increase as construction continues. When completed in 2022, Miraah will comprise 36 greenhouses and cover 3 square kilometres, generating 6 000 t of steam daily, saving 150 million cubic metres of gas per year.

Overview of selected markets

In the world's largest market, **China,** total annual installations continued to decline in 2015 for the second year in a row. An estimated 30 GW_{th} was installed, 17% less than 2014 because of a weakening economic environment, a slowdown in the new-build housing market and the withdrawal of government support in recent years. The rural incentive programme, which provided subsidised solar hot water (SHW) systems for rural households, has finished and has not been renewed; the subsidies for high-efficiency solar water heaters under the China Energy Label scheme ended in 2013; and the demonstration cities programme, which promoted solar thermal systems in municipalities, has been suspended. Outside of these programmes, the economic attractiveness of SHW coupled with local building obligations has driven installations, but the growth has not been able to offset the slowing housing market. Still, China's solar thermal deployment has surpassed government targets. By the end of 2015, total installed capacity is estimated to have reached 309 GW_{th}, 10% more than the 280 GW_{th} target (equivalent to 400 million square metres [m^2]) under the 12th Five-Year Plan (FYP).

Over the medium term, rising heat demand, growing concerns over air pollution from coal-fired heat, and new targets proposed in the draft 13th (FYP) to double collector capacity by 2020 (to 800 million square metres [m^2]) are seen as drivers for solar thermal deployment, though the pace of growth is expected to be slower than over the previous six years. The dominant market segment, DHW-S, has been shrinking despite having one of the lowest solar heating costs (USD 54/MWh to USD 118/MWh), and it remains to be seen if those systems will be competitive with heat pumps or electric boilers in the absence of government support. However, larger systems may become more attractive. In 2014, almost 60% of the new installations were for DHW-L systems in multifamily buildings and the commercial sector (Mauthner, Weiss and Spörk-Dür, 2016).

In some major European markets, the slowdown in the construction of new buildings, an undeveloped installer network, lower fossil fuel prices and insufficient support continue to challenge solar thermal deployment. In **Germany**, support levels under the market incentive programme were unable to offset the high solar thermal investment costs, which are in part due to complex and expensive installations. As a result, applications for support fell for the second year in a rowand total annual installations shrank by over 12% while sales for oil boilers increased in 2015 (BDH, 2016). In **Austria**, where the national incentive scheme for DHW systems was restarted in 2015, compliance with different local support regulations has not been uniform, which limited deployment in some regions. High investment costs, lower electricity prices and falling gas prices have also challenged the attractiveness of solar heating in **France** despite support under the Fonds Chaleur programme, as total annual installations continued to fall by 33% to 0.1 GW_{th} in 2015. The business case for solar thermal was further weakened when in 2015, tax credits were changed from technology-specific to technology-neutral for all so-called high-performance heating options. This has put higher-cost renewable heat technologies at a disadvantage against lower-cost ones such as condensing boilers (Eurobserv'ER, 2016).

Going forward, improving economics should drive deployment in Germany, after incentive levels for several market segments were raised in 2015 and additional support became available for renovation projects that link renewable heat installations with energy efficiency improvements. A new option for a performance-based incentive for SHW and space heating in certain building types may also stimulate additional growth. A less positive outlook exists for DHW-S in Austria, as funds for the subsidy scheme were halved in 2016 compared with 2015. However, two incentive programmes for industrial process heat and solar district heating introduced in 2016 are expected to drive deployment of large-scale systems. Delays in multi-occupancy building regulations for energy performance and poor consumer perception remain barriers to deployment in France. In the United Kingdom, support for solar thermal under the RHI is currently under review and may cease completely.

Elsewhere in Europe, competitiveness with other heating alternatives has been the main driver for solar thermal growth, particularly in warmer climates with high insolation and heat demands well suited for lower-cost thermosiphon systems. Strong growth continued in **Turkey**, where total annual installations increased by 10%, with DHW-L growing the fastest, particularly in the tourism sector. Turkey is one of the few markets where most of the growth has occurred without government incentives, owing to low equipment costs from a robust supply chain and good insolation (REN21, 2016). Growth is expected to continue, particularly in commercial and industry sectors. Similar climatic conditions and a growing hot water demand from the tourism industry have also driven the market in **Greece**, which installed 0.2 GW_{th} in 2015 to become the second-largest annual market in the European Union after Germany. A potential tax credit and decrease in VAT on new system installations are expected to further stimulate growth. Recent developments in **Spain** have also been positive despite the 6% drop in annual installations in

2015. The decline was primarily due to the termination of incentives in Andalusia. Outside of this region, unsubsidised solar thermal installations continued to grow as a result of strict building regulations, innovative financing models such as leasing and ESCOs, and effective customer communication strategies (Eurobserv'ER, 2016). Solar thermal's economic attractiveness should remain a key driver for future growth, particularly for collective systems, which outpaced individual installations for the first time in 2015.

Solar thermal deployment in Latin America and sub-Saharan Africa has largely been driven by the need to reduce peak electricity demand in supply-constrained markets such as **Brazil** and **South Africa**, or to provide first-time access to hot water. High electricity prices, local building codes, and government housing programmes have driven growth in Brazil. Total annual installations remained steady in 2015 at 1 GW_{th}, making Brazil the world's third-largest annual market, but the weakening economic climate may challenge deployment going forward. Growth in **India** also remained stable in 2015, though the end of the grant scheme in the residential sector could pose a risk to future deployment. However, prospects for further solar process heat are promising given India's high reliance on imported diesel for industrial heat demand. Government support for concentrating solar steam generation for community cooking, laundry and cooling should foster further developments while an industry call for a renewable heating obligation for process heat could stimulate growth if turned into law.

Geothermal for heat

Geothermal energy can be used to produce electricity, using geothermal heat to produce steam to run turbines. However, the heat can also be used directly in buildings, spas and swimming pools, district heating systems, and within the agriculture (e.g. greenhouses) and industry sectors. As geothermal direct use has lower temperature requirements than geothermal electricity generation, it is feasible over a wide geographical area. For example, geothermal heat can be economically extracted from deep aquifer systems. In many parts of the globe, locations can be reached within a depth of 3 kilometres, with moderate heat flow in excess of 50 MW/m^2 to 60 MW/m^2 and rock and fluid temperatures greater than 60^oC (IEA, 2011).

GSHPs are also often referred to as geothermal heat pumps. This report differentiates in this section between direct geothermal heat use that relies on the heat generated by the earth's geological processes, and heat pumps that use electricity to harness solar heat stored in the ground. GSHPs for residential use are discussed separately in the next section. However, owing to inconsistent statistics reporting, some countries are reporting heat pumps as geothermal energy, hence some inaccuracies and double counting are unavoidable. Furthermore, in some applications, heat pumps are used to exploit low-temperature geothermal heat (e.g. from aquifers), so there is a degree of overlap that is covered in this section.

Drivers and challenges

Geothermal at present provides the smallest share of all renewable heat technologies, and in 2014 produced just 7.9 Mtoe (0.3 EJ), or 2% of global renewable heat. This is a long way from the 5.8 EJ envisaged for 2050 in the 2011 IEA geothermal *Technology Roadmap* (IEA,2011). A number of drivers and challenges exist that are set out in Table 4.4 below.

Table 4.4 Geothermal heating drivers and challenges

Drivers	Challenges
Resource availability, especially where there are shallow resources such as hot thermal springs that are easy and cheap to exploit. Potential from deep aquifers is more widespread.	Extraction from deep resources such as hot aquifers is technically more difficult. Geological and drilling expertise is needed and upfront costs can be very high, while success is not necessarily guaranteed. Expertise may not exist in developing countries – technical co-operation programmes can be important.
Financial incentive programmes.	Need to make available funding for expensive drilling operations that may not be successful (e.g. risk guarantees).
Carbon targets and requirements to decarbonise the heating sector.	Need district heating infrastructure in the right locations to exploit geothermal (e.g. from hot aquifers). Potentially high infrastructure costs if necessary to build/extend district heating.

Cost analysis

As a result of the large variety of direct use applications, it is difficult to source comparable cost data. The 2011 IEA geothermal *Technology Roadmap* reported that geothermal district heating costs range from USD 45/MWh_{th} to USD 85/MWh_{th}. Costs of heating greenhouses vary between USD 40/MWh_{th} and USD 50/MWh_{th}. Similar costs are reported in a more recent paper by Greller and Bieberbach (2015) from Munich's local utility. This suggests costs for district heating based on deep geothermal of around USD 50/MWh_{th}, broadly similar to costs for large-scale gas boilers. They found that geothermal costs are much lower than the costs of other renewable heat options for district heating such as woodchip co-generation, solar thermal with storage or large-scale heat pumps.

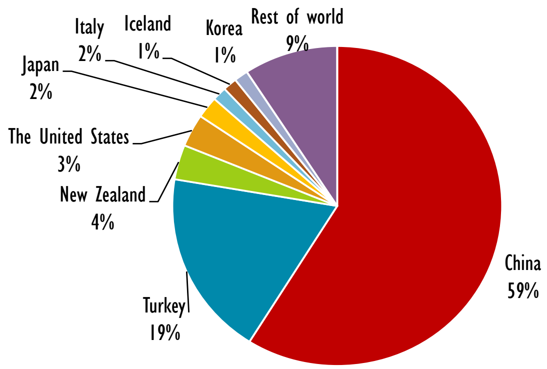
Global overview

Data availability for geothermal direct use is neither comprehensive nor consistent among sources. IEA statistics report geothermal use in total final energy consumption. Accordingly, geothermal consumption was 0.33 EJ in 2014. However, as mentioned above, this includes some heat pump reporting. Lund and Boyd (2015) have carried out regular surveys, with the most recent results published in 2015. These suggest lower consumption at 0.26 EJ, with heat pumps excluded. The IEA Geothermal Technology Collaboration Programme is carrying out a project on direct use statistics, with the aim to ultimately report more consistent data.

To date, most developments have been in countries with easily accessible high-temperature geothermal fields. According to IEA statistics, China has the highest geothermal direct use, followed by Turkey. These two countries account for 78% of global geothermal heat use (Figure 4.10).[20] Other countries with relatively large direct geothermal consumption include New Zealand, the United States, Japan and Italy. Recently, the use of direct geothermal has also expanded in other markets such as Germany and France, where aquifers are being increasingly exploited. On a share of heat demand basis, Iceland has the highest use with 90% of space heating and hot water demand being met by geothermal district heating.

[20] N.B. Lund and Boyd (2015) report much lower shares for China and Turkey, suggesting some data discrepancies.

Figure 4.10 Geothermal direct use by country, (2014)



Note: *Rest of the world* includes, for example, Switzerland, which reports 0.01 EJ of geothermal heat, but this is actually primarily from GSHPs.

Source: IEA (2016a), *World Energy Statistics and Balances 2016*, www.iea.org/statistics/.

In terms of uses, bathing and swimming currently account for the largest share of geothermal direct use (45%), followed by space heating (34%). Industrial use is very small, accounting for only 4% of geothermal direct use (Lund and Boyd, 2015), although it is important in countries such as New Zealand. For space heating, the expansion of use in district heating systems has been a key driver, with China at the forefront of this trend.

In the medium term, geothermal direct use is likely to continue expanding. Global growth is expected at 75% over 2014-21, from 0.33 EJ to 0.59 EJ. More than half of this would come from China, driven by the proposed 13th FYP targets. However, geothermal heat is anticipated to remain small compared with other renewable heat options, with a share of still only 3% of renewable heat produced in 2021.

Overview of selected markets

Much of **China**'s heat supply in cities is produced by coal and contributes significantly to air pollution problems. Geothermal direct use is being developed as a key alternative to coal in heating and cooling. For example, Baoding in Hebei province, which was China's most polluted city in 2014, was declared one of China's "geothermal" cities by the Ministry of Land and Resources. The aim is to further develop district heating as a way to reduce the air pollution problem.

The 12th FYP (2011-15) included two targets for geothermal direct use – to supply 580 000 m^2 of buildings with geothermal heating and cooling (including heat pumps), as well as geothermal hot water supply to 1.2 million homes. The 13th FYP (2016-20) aims to further expand geothermal heating, although specific targets have yet to be confirmed. China is also expected to publish a five-year geothermal development plan.

By the end of 2014, geothermal district heating provided heat for 60.32 million m^2, with more than half of this in the provinces of Tianjin and Hebei (Zheng et al., 2015). This is still only a very small percentage of heat demand, accounting for only around 1% of district heating supply. However, in some localities, geothermal district heating already supplies the majority of heat demand. For example, in Xiongxian County, district heating based on 78 geothermal wells supplies 2.7 million m^2, accounting for 92% of the centrally supplied heat demand. The district heating scheme was developed jointly by Chinese and Icelandic companies (SinopecGE, 2016).

In the medium term, China will be the key contributor to global geothermal direct use development, as local air pollution concerns drive further expansion of geothermal district heating.

New Zealand has excellent geothermal potential. Geothermal power generation (26.13 petajoules [PJ]) exceeds direct use for heat (11.66 PJ), with heat applications that are primarily industry-based (MBIE, 2015). For example, the Kawerau geothermal field has provided process steam to timber mills and pulp and paper manufacturing since 1957 (Carey et al., 2015). In 2010, supply was expanded to a tissue manufacturing facility. Prior to 2013, the Kawerau site accounted for half of the total New Zealand direct geothermal heat use and used half of the world's total direct geothermal industrial energy. However, with the shrinking global consumption of newsprint, one of the two paper production lines was closed at the beginning of 2013, significantly reducing direct use at that site.

The New Zealand government set a target in its 2011 energy strategy for business to use, by 2025, up to 9.5 PJ per year of energy from woody biomass or the direct use geothermal additional to that used in 2005 (MED, 2011). Between 2005 and 2014 (the latest figures available), growth in the direct use of geothermal was only 2.26 PJ, while the use of biomass actually declined. If present growth rates continue, this target is unlikely to be achieved. There are no financial support mechanisms or other incentives to stimulate the market.

Significant new development is taking place in Christchurch, where the central business district is being rebuilt after major earthquake damage. This includes several energy nodes to provide heating and cooling to large commercial and service facilities. The systems will include heat pumps using heat from the local aquifer. As the rebuilding continues over the next five or so years, these systems will come into operation.

Germany lacks shallow geothermal resources and relies primarily on exploiting deep aquifers. There are more than 180 geothermal direct use plants, but most of these are small plants at thermal spas. However, there are 24 larger deep geothermal plants supplying district heating networks, with an installed capacity of 285 MW_{th}. Most of these plants are located in the North German Basin, the Molasse Basin in Southern Germany, or along the Upper Rhine Graben.

In 2015, geothermal direct use produced 1 058 gigawatt-hours (GWh) (3.8 PJ), contributing just 0.7% of Germany's renewable heat production (BMWi, 2016). After six new plants became operational in 2014, 2015 saw no further expansion. However, two plants (41 MW_{th}) are currently under construction near Munich (Box 4.3), along with a 6 MW_{th} plant near Frankfurt. These plants are expected to come on line in 2016-17. Another 43 projects are at the planning stage (Bundesverband für Geothermie, 2016).

Box 4.3 Geothermal and Munich's district heating system

Stadtwerke München (SWM), one of Germany's largest municipal utilities, is at the forefront of Germany's geothermal heat development. SWM has committed itself to supplying 100% of its growing district heating demand from renewables by 2040. It sees direct use geothermal as the main option for reaching this ambition, with a good potential from the southern Bavarian Molasse basin. SWM opened its first geothermal plant in 2004 and its second in 2014. A third plant is expected to be commissioned in 2016, more than doubling SWM's geothermal capacity to 37 MW_{th}. In the pursuit of its ambitious 2040 target, SWM is currently working on feasibility study for a further 400 MW_{th} of deep geothermal heat supply and expects to open another five plants by 2025.

The German government supports geothermal plants through its market incentive (*Marktanreiz*) programme. This provides low-interest loans and loan payback subsidies for both geothermal drilling and above-ground installations. The incentives were improved in 2015, for example now providing support for four boreholes instead of previously two. While this funding will ensure that direct use geothermal will continue to grow in Germany, it will remain a small contributor to overall renewable heat production over the medium term.

Heat pumps

Heat pumps offer a means to utilise renewable solar heat stored in the ground, air, or water sources such as lakes and rivers, and can make an important contribution to decarbonising heating, particularly in the buildings sector. In the European Union, the RED recognises the ability of heat pumps to harness renewable energy. Under the methodology used by the European Commission (EC), the heat extracted from the environment by a heat pump (ambient heat) is considered renewable as long as a minimum seasonal performance factor (SPF) for the unit is met.[21] However, this recognition is not yet reflected globally as heat pumps are regarded as an energy efficiency measure in many markets.

Air source heat pumps (ASHPs) make up the largest share of the global heat pump market, although accurate data are not available on the number of systems worldwide due to variations in how heat pumps are defined and used. In Europe, around 82% of 2015 heat pump installations (over 6.3 million units) were ASHPs. However, most of these are reversible ASHPs utilised primarily for cooling in mild and warmer climates, with only around 10% of installed capacity deployed in colder climates in 2014 (EC, 2016b). As this chapter focuses on heating rather than cooling, the key focus of this section is on GSHPs, which are mainly utilised for heating in colder climates where the energy consumption for heating in buildings is highest. Over 70% of heat generated from GSHPs in 2014 came from installations in colder climates (EC, 2016b).

GSHPs are principally utilised for space heating in buildings and allow for the transformation of heat from a lower to higher temperature level by using an external energy source (IEA, 2011), effectively making use of the ability of the ground to store solar heat. GSHPs are also being used to provide inter-seasonal storage (Box 4.4). GSHPs can typically provide high efficiencies of three to five units[22] of useful heat output for each unit of input energy. This ratio is termed the unit's COP. In the majority of heat pump systems, particularly in the residential sector, the energy input used is electricity. Many countries support GSHP deployment as a way to meet climate change objectives, with the emissions savings delivered from heat pumps increasing as the carbon intensity of grid electricity decreases.

[21] The seasonal performance factor is the average coefficient of performance (COP), i.e. ratio of heat production to energy input, of a heat pump over an extended period, such as a full heating season. As such, SPF values depend heavily on the climate and the difference between the ground and inside air temperature. The minimum acceptable SPF of electrically driven heat pump to be considered renewable under the EC methodology is 2.5 and for a thermally driven heat pump is 1.15.

[22] By comparison, a well-designed and specified ASHP system will typically produce a COP of around 3.

Box 4.4 Innovative approaches in GSHP utilisation

Innovative large-scale GSHP systems are being installed in the well-developed Nordic heat pump markets. Two types of systems, aquifer thermal energy storage and borehole thermal energy storage, which provide inter-seasonal storage of heat in the ground and water, have been deployed over the last decade in the Nordic countries. Such systems are especially effective in areas with high energy demand where waste heat from cooling in the summer can be stored for use in winter, raising overall system efficiency and ensuring that long-term heat depletion in the ground is avoided. Today about 280 of the 15 000 GSHP installations in Norway are medium- to large-scale systems over 50 kW that utilise boreholes as heat exchangers with the ground. Norway boasts the two largest such installations in the world (Midttomme et al., n.d.). There is also growing interest in the use of larger-scale heat pumps within district heating schemes, as well as to serve industrial processes, which GSHP systems using inter-seasonal storage could fulfil.

Drivers and challenges

A non-exhaustive general overview of drivers and challenges to the growth of GSHP systems in the buildings sector is provided in Table 4.5 below.

Table 4.5 Residential GSHP market expansion drivers and challenges

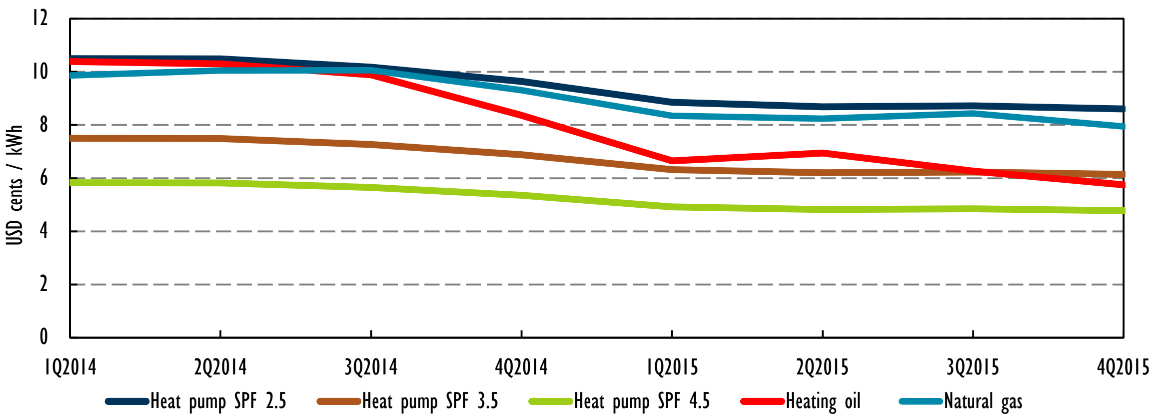
Drivers	Challenges
Higher renewable electricity shares in power systems increase heat pump emissions reduction potential.	Initial GSHP capital investment higher than for many fossil fuel domestic heating systems and also ASHPs. High electricity prices also mean higher running costs than fossil fuel boilers.
High-efficiency operation ensures competitive operational costs versus most fossil heating fuels, and hybrid solutions enable augmentation of existing fossil heating systems with heat pumps.	Development of qualified installer and system specifier networks to ensure well-designed and installed systems that realise high system COPs.
Policy support in European markets seeking to increase renewable heat shares in accordance with RED targets.	Inefficiently insulated housing stock increases heat demand and peak loads, potentially requiring backup electric heating. This results in higher capital cost and reduced COP for high-temperature heat distribution, thus increasing operational costs.
New buildings and building renovation offer the opportunity to install heat pumps and low-temperature heat emitters without disruption to building occupants.	Retrofit market is challenging because of disruption caused from ground-loop installation and the potential requirement to install low-temperature heat distribution system.
Innovative commercial building solutions using inter-seasonal heat storage in the ground to utilise waste cooling heat from summer during the heating season.	Not suitable for buildings without an area to install the ground loop/borehole.

Cost analysis

GSHPs can be capital-intensive, primarily with regard to the costs associated with borehole drilling or ground-loop installation as well as installing suitable low-temperature heat distribution systems. Generally, installation costs are lower in new-build properties than for retrofit installations, where building structural changes and the possible need to install new heat distribution infrastructure increase costs. Investment costs can vary depending on factors including geographic location, which dictates land prices, and if a vertical or horizontal ground loop is utilised. Installation costs for GSHP systems can be several times that of an air-source system with the same heating capacity, and can range from around USD 1 800/kW_{th} to USD 2 600/kW_{th} (ASHRAE, 2012). The most expensive component for vertical systems is the borehole at around 60% of the total installation cost. Given the higher initial investment costs of GSHPs in the residential sector compared with fossil fuel heating systems, economic incentives are anticipated to continue to play a key role in market development.

With regard to operational costs, well-specified and -installed GSHPs can be cost-competitive compared with fossil fuel alternatives (i.e. heating oil boilers), and their higher efficiency should generally offer lower operational costs than lower-capital-cost ASHPs. The higher efficiency operation from heat pumps will also always deliver lower operational costs, as well as improved controllability, compared with electric heating. Higher capital costs compared with fossil fuel alternatives means competitiveness is challenged during periods of lower heating oil costs, in areas with a connection to the natural gas grid and where electricity costs are high, as this affects both the cost of input electricity to the heat pump and backup electrical resistance (if used). The operational costs for GSHP systems are variable and link to both the cost of input electricity and the SPF of the heat pump unit as determined by the heat pump system characteristics, input temperature (e.g. ground or ambient air) and building thermal efficiency. Based on average 2015 OECD Europe electricity prices, GSHP operational costs would vary between USD 0.05/kWh and USD 0.09/kWh (Figure 4.11).

Figure 4.11 Average operational costs of domestic heat pump installations based on their SPF compared with electricity and natural gas prices in the European Union



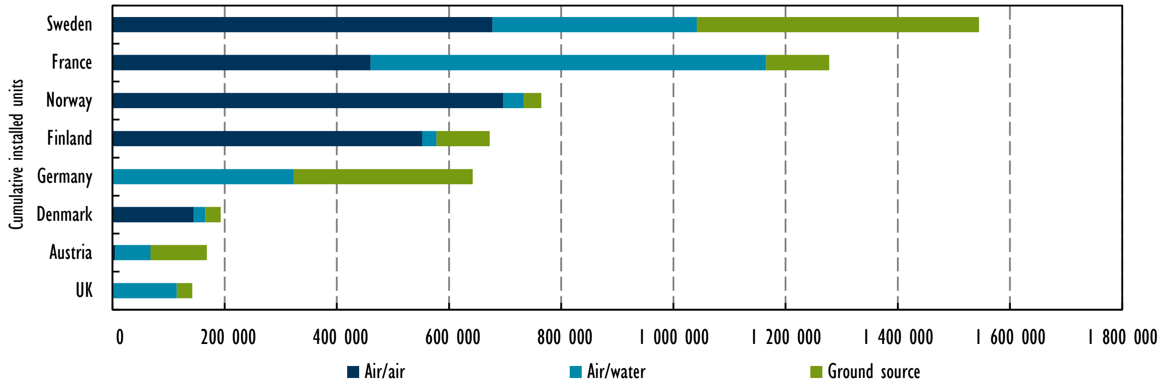
Note: SPF = seasonal performance factor

Source: IEA (2016c), *IEA Energy Prices and Taxes* (database), www.iea.org/statistics/.

Overview of selected markets

In 2015, global GSHP installations reached 4.16 million, with the market growing at an annual average growth rate of around 8.5% from 2010-15 (Lund and Boyd, 2015). The US market currently has 1.4 million GSHP units and is experiencing an 8% annual growth rate. Nordic countries such as Sweden, Norway and Denmark have among the highest number of GSHP installations per capita. In fact, 20% of buildings in Sweden are heated using GSHPs (Lund and Boyd, 2015). The total European heat pump stock (excluding industrial systems) reached approximately 7.5 million installations in 2014; GSHPs accounted for 19% (or 1.4 million units) of these, with key markets in Sweden, Germany and France (EHPA, 2016) (Figure 4.12).

Figure 4.12 Cumulative installations by type of heat pump for selected European countries, (2015)



Note: Spain and Italy are not included in this chart as heat pump deployment is primarily ASHPs used for cooling. Industrial uses of heat pumps of over 2 000 units, due to high deployment in Portugal, and district heating, which is seeing modest deployment, are also excluded.

Source: EHPA (European Heat Pump Association) (2016), *Heat Pump Sales in Germany – 2015*.

Total heat pump installations in the European Union were estimated at 880 000 in 2015[23]. However, annual installations of GSHPs in Europe have been slowing. The slowdown in GSHP deployment comes alongside stronger ASHP installations in countries such as Germany that historically boasted larger GSHP sales, and in Nordic countries including Sweden and Denmark. High investment costs may be a limiting factor on market growth, especially in countries with limited financial support for GSHPs. European legislation to ensure a more efficient building stock, as well as 2020 renewable energy targets, will continue to shape the European heat pump market.

Germany remains one of the most successful GSHP markets in terms of policy support and deployment thanks to the establishment of the renewable energy heating and cooling target of 14% by 2020. Current legislation requires all new buildings to incorporate renewable heating and cooling, with GSHPs and other eligible options to ensure compliance. Additionally, the Federal Office for Economic Affairs and Export Control (BAFA) increased its incentive programme in 2015, to offer grants up to USD 4 400 per installation of high-performance[24] heat pump systems of no more than 100 kW (BAFA, n.d.). The GSHP market stands at a cumulative total of around 325 000 units installed (Weber, 2016). GSHP sales were around 17 000 units in 2015, compared with 18 500 units sold in 2014 (EHPA, 2016). New regulatory requirements, including the need for site investigations and additional administrative costs, have been introduced in some states.

The United Kingdom heat pump market is still in the early stages of development and smaller relative to others in Europe with approximately 27 000 GSHPs installed by 2015 (2% of the European total) and around 280 MW_{th} of installed capacity (Lund and Boyd, 2015). Despite this comparatively low level of installations, strong potential exists with the requirement for the United Kingdom to make progress in renewable heating in order to achieve its RED target of 15% renewable energy across all sectors by 2020, and the country's longer-term commitment to reducing its greenhouse gas (GHG) emissions by 80%, relative to 1990 levels, by 2050. Support for GSHP systems was introduced

[23] Heat pump sales data for this section provided by the European Heat Pump Association.

[24] In existing buildings, air-to-water heat pumps are eligible for installation grants only if the system's SPF is greater than 3.5. In the case of GSHPs (ground-to-water) or hydraulic (water-to-water) heat pumps, the required SPF must exceed 3.8 and over 4 for non-residential buildings.

with the launch of the RHI in 2011, for non-residential installations, and subsequent introduction of the domestic RHI in 2014. Between the launch of the domestic RHI in April 2014 and August 2016, around 2 300 new GSHP systems and over 11 000 new ASHPs were accredited under the scheme[25] (BEIS, 2016b). In the 2016 consultation on the RHI scheme, the prospect of allowing shared ground loops among different systems was proposed as a means to reduce initial capital costs. Higher tariffs for GSHPs are also under consideration.

In **the United States** the GSHP market is growing by around 7% annually (totalling 1.4 million units in 2015) with 40% of new installations occurring in the residential sector. The current installed capacity of GSHPs is around 16 800 MW_{th}, while generation stands at around 18 500 GWh (Boyd, Sifford and Lund, 2015). Despite being one of the largest GSHP markets, there is still great untapped potential. In the Northeast and Midwest of the country, colder climates have the highest average energy consumption for heating per household/year, around 17.6 MWh compared with 6.4 MWh in the South, where the largest heat pump market is located. However, this is primarily for cooling.

The potential for further GSHP expansion into colder climates is significant. A number of policies support deployment including a 30% residential renewable energy tax credit applied to GSHPs (due for expiration in December 2016), a 10% Investment Tax Credit for all expenditures on geothermal equipment, accelerated depreciation, and USD 50 million dedicated to GSHP demonstration projects (NREL, 2014). In addition to federal incentives, a growing number of states offer tax credits, with Maryland the first state to approve GSHP eligibility for Renewable Energy Credits. Seven states include GSHPs in their mandatory RPS programmes, three of which are located in colder climates. While the US GSHP market continues to grow, high initial capital costs continue to be the largest barrier to sustained medium-term GSHP market expansion.

Special focus: Renewable heat policies

Overview

Heat markets are complex and fragmented, and generally less well understood than electricity markets, providing a challenge to policy makers. On the demand side, heat demand in buildings varies enormously according to factors such as climate, building fabric efficiency and occupancy, while in industry a multitude of processes have a range of heat requirements. On the supply side, there are many different space and water heating options offered, with numerous actors involved, from large multinational heating equipment manufacturers to small local installers. Renewable heat faces multiple economic and non-economic barriers to compete in these markets.

In terms of economics, while there are cases where renewable heat options can compete with fossil fuels and can even be the preferred option (e.g. in the food or paper and pulp industries, where often co-products are available as a free fuel), in most cases policy intervention is needed to initiate or accelerate the deployment of renewable heat. As discussed above, the current low fossil fuel prices are a particular challenge but policies also need to address many other economic barriers (Table 4.6).

[25] "New" refers to systems commissioned after scheme launch.

Table 4.6 Economic barriers and policy solutions for renewable heat

Barrier	Barrier explanation	Policy solutions	Policy examples
Capital costs	Higher capital costs than fossil fuel alternatives.	Investment support via grants and low interest loans.	France zero-interest loans. Green mortgage schemes.
	Access to affordable finance and capital for renewable heat investments.	Heat generation-based subsidies to reduce payback periods and ESCO approaches.	Germany market incentive programme and RHI in the United Kingdom.
No level playing field with fossil heating fuels	Externalities such as carbon or air quality impacts not included for fossil heating fuels.	Energy and carbon taxation.	Carbon taxation in Nordic countries.
	Fossil fuel subsidisation.	Removal of fossil fuel subsidies.	Fossil fuel subsidy reform in countries such as India, Malaysia and Indonesia.
Current low and cyclical fossil fuel prices	Achieving running cost savings to pay back higher capital costs is more challenging.	Adjustable energy/carbon taxes to provide price stability, ''floor'' price.	Currently not identified specifically for heat.
	Reduced certainty over long-term competitiveness of renewable solutions versus fossil heating.	Mechanisms to increase liquidity and tradability of biomass fuels.	Baltpool Exchange, Lithuania, ENplus certification, futures contracts for wood pellets.
Split incentives in the private rented sector	The building owner usually is required to invest in a renewable heating system, but the occupier/tenant receives the benefit of running cost reductions.	Grants and ESCO approaches. Measures to pass the initial investment cost on to a third party, or obligations (e.g. improvement in energy performance).	Green Deal scheme in the United Kingdom (now discontinued). Germany (Baden-Württemberg renewable heat law).
Lack of economies of scale resulting in higher system costs	In the early stage of market growth, developing supply chains can lead to higher system costs.	Long-term policy support measures to allow supplier base and supply chains to grow.	Fonds Chaleur scheme in France launched in 2009 with 2020 targets.
	Lack of district heating infrastructure in many countries reduces cost-effective opportunities to integrate renewable heat.	Incentives for local authorities, cities and industry to encourage investment in efficient district heating schemes with low-carbon supply.	Municipality district heating projects in Sweden, Denmark and Germany. Heat Networks Delivery Unit funding in the United Kingdom.

Carbon taxation can be a cost-effective instrument to overcome economic barriers and increase renewable heat consumption, through providing price signals to move away from fossil fuels, particularly those with high carbon content, towards renewable energy sources, therefore increasing the relative competitiveness of renewable heat. This has been demonstrated in Sweden, where the introduction of carbon taxation in 1991 has resulted in the transition from heating oil to biomass within district heating. The 2015 carbon tax of 1 120 Swedish krona per tonne of CO_2 (tCO_2)

(USD 133/tCO_2) almost doubles the price of heating oil. While oil accounted for 90% of fuel use in district heating plants at the end of the 1970s, by 2014 its share had dropped to just 2%, with biomass accounting for 70% (Andersson, 2015).

France has also established carbon taxation, currently EUR 22/tCO_2 (USD 24/tCO_2), with the recent energy transition law including the commitment to increase this further to EUR 56/tCO_2 (USD 62/tCO_2) by 2020. Carbon taxation has been introduced at varying levels in other countries such as Denmark, Finland, Ireland, Mexico and the United Kingdom, as well as some Canadian provinces. If a guaranteed level of emissions reduction is required, cap-and-trade emissions trading can be utilised, such as the case with the EU emissions trading scheme (EU ETS), with China also having announced the intention for a national emissions trading system in 2017 to include emissions from prominent industrial sectors.

While carbon taxation and other economic instruments have been successful in some countries and sectors in addressing economic barriers, in many cases a range of non-economic barriers also hinder deployment of renewable heat technologies (Table 4.7).

Despite the multitude of barriers and the large contribution of heat to final energy demand and emissions, to date policy makers in most countries have mainly focused their renewables policies on electricity. For example, while around 170 countries have targets for renewable electricity, renewable heat targets are only in place in around 50 countries.

Most commonly, these are targets for individual renewable heat technologies and can be found both in OECD countries and in emerging economies. For example, South Africa originally set a solar water heating target in 2009. This has since been updated and the country now aims to have 5 million homes with solar thermal water heating by 2030. Thailand's 2015 Alternative Energy Development Plan includes heat targets for solar thermal, biomass, biogas and municipal waste to be reached by 2036. China's 13th FYP sets new targets for solar water heating and geothermal heat to be reached by 2021.

Very few countries have set themselves targets for a share of total heat demand to come from renewables. EU countries are exceptions; the EU RED requires 20% of final energy consumption to be met by renewables in 2020, with contributions from electricity, heating, cooling and transport. Under the RED, member states have established indicative heat shares in their National Renewable Energy Action Plans (NREAPs), and some have set specific renewable heat targets for 2020 or even beyond. For example, Denmark has a target to supply all heat from renewables by 2035, up from 38.4% in 2014.

While targets are important for providing a sense of direction, their implementation will depend on effective policy measures. Again, the global landscape for renewable heat measures is less extensive than for electricity. The joint IEA/International Renewable Energy Agency (IRENA) renewable policy database lists 582 policy instruments in force for renewable electricity, yet only 158 for heating and cooling across 75 countries[26].

[26] For further information, refer to IEA/IRENA *Joint Policies and Measures* database for renewable energy: www.iea.org/policiesandmeasures/renewableenergy.

Table 4.7 Non-economic barriers and policy solutions for renewable heat

Barrier	Barrier explanation	Policy solutions	Policy examples
Building suitability	Renewable heat options may not be suitable in certain buildings (e.g. apartments). Low energy efficiency in building stock results in higher peak loads and increased capital costs, as well as reducing heat pump system efficiency.	Integrated energy efficiency and renewable heat grant schemes. Ensuring high efficiency through building codes.	Zero-interest loans in France and KfW programmes in Germany. EU Energy Performance in Buildings Directive.
Industrial heat requirements	Can be challenging for some renewable technologies to fully meet the temperature, pressure and quantity of heat required by some industrial users. Restrictions are also due to stringent emission requirements.	Technology-related research, development and demonstration funding. Carbon taxation on industrial emissions to encourage use where possible.	Horizon 2020 funding in the European Union. EU ETS in the European Union.
Lack of awareness of and confidence in renewable heat technologies	Can apply to households, heating system specifiers and lenders. Perception of renewable systems as inferior in terms of user comfort, exacerbated by failures of previous poorly designed/installed systems.	Information programmes and advice provision (e.g. through energy agencies) Equipment certification and standards as well as after-installation technical support services.	RHI roadshows in the United Kingdom. Microgeneration Certification Scheme (MSC) in the United Kingdom.
Early stage of industry development	Need for trained workforce to undertake design/specification, manufacturing, installation and O&M.	Training and certification programmes. Better recognition of technology certification among countries.	Multiple. Heat Pump Keymark scheme.
Distressed purchase and consumer inertia	Solution needed at short notice when existing boiler breaks down, tends to favour replacement with the same (e.g. fossil fuel) technology.	Renewable obligation for boiler replacement.	Germany (Baden-Württemberg renewable heat law).
Disruption and "hassle" factors	Retrofit installation of renewable heat systems may entail disruption (e.g. underfloor heating, biomass fuel storage). Renewable technologies also often require more space and can result in higher maintenance requirements.	District heating to allow off-site deployment. Installation of renewable systems during wider building renovation and regulations to ensure integration in new-build properties.	Municipality activities in Nordic countries. Merton Rule policies for commercial buildings in the United Kingdom.
Requirement to obtain reliable heat demand availability data	Needed to select favourable locations for installations and develop sales/maintenance networks. Also relates to heat demand mapping for planning of district heating networks.	Organisation and funding for heat mapping and zoning by local authorities.	Heat Networks Delivery Unit support in the United Kingdom, Denmark (zoning).

This report carried out in-depth analysis of the renewable heat policies of around 25 countries, representing a variety of types and sizes of heat markets (Table 4.8). This revealed that the most common policy instruments for renewable heat are:

- Fiscal measures – most often grants, subsidies or tax credits; primarily for households and often connected to building renovation and energy efficiency (Box 4.5). In some countries energy or carbon taxes have been applied.
- Building standards (specifically new-build properties) that either require a certain percentage of heat supplied from renewables or specifically have a requirement for solar thermal system for hot water generation.

Table 4.8 Heat policy instruments in selected countries

	Regulatory support			Economic support						
Country	**Target**	**SWH targets**	**Building obligations**	**Generation-based incentives**	**Green certificates**	**Capital grants and subsidies**	**Soft loans**	**Tax incentives**	**Installers trainings and certification**	**Exemplary role of public buildings**
Argentina						✓				✔
Australia			✓		✔	✔				
Belgium	✔		✔			✓	✓	✔	✔	
Bulgaria	✔		✔				✔	✔	✔	
Brazil		2.86 million 2011-14	✓							
Canada						✓	✓	✔		
Chile								✔		
China		800 million m2 of solar thermal by 2020	✓			✔				
Denmark	39.8%*		✔					✔	✔	✔
France	38.0%**		✔			✔	✔	✔	✔	✔
Germany	15.5%*		✔	✔		✔	✔		✔	
India		20 million m2 of solar thermal by 2022	✓			✔		✔		
Italy	17.1%		✔	✔			✔	✔	✔	✔
Japan						✔				
Korea		2020: 342 ktoe and 2030: 1882 ktoe (RPS)	✔			✔				✔
Mexico			✔					✔		
Poland	17.5%*					✔	✔		✔	
Netherlands			✔	✔		✔		✔	✔	
Romania	22.05%*					✔			✔	
Spain	18.9%*		✔			✔			✔	
South Africa			✔							
Sweden	62.1%*							✔		
Thailand		300 000 SWH collectors		✔						
United Kingdom	12.0%*		✔	✔		✔	✔		✔	
United States			✓			✓	✓	✓		

Notes: * NREAP, targets to be reached by 2020; ** Target established in 2015 in Energy Transition Act to be reached by 2030.
✔ = national-level policy; ✓ = state/provincial-level policy.
ktoe = thousand tonnes of oil equivalent; SWH = solar water heating; RPS = renewable portfolio standard.

Source:IEA/IRENA (2016), *Joint Policies and Measures Database for Renewable Energy*, ww.iea.org/policiesandmeasures/renewableenergy.

Building standards for new-build properties are particularly important in emerging economies where there is a rapid expansion of the built environment, especially in cities. For example, South Africa specified in 2014 that at least 50% of water heating requirements in new buildings need to be met by renewables or other non-resistive electric heating. The aim is to reduce peak demand for electricity.

Some innovative instruments have been tried out in recent years:

- United Kingdom: A long-term generation-based financial support incentive for renewable heat, with heat metering for non-domestic systems.
- Germany: The state of Baden-Württemberg requires renewable heat when boilers are replaced in existing buildings.
- United States: In some states inclusion of heat in RPS, which previously were mainly electricity-focused.

In some countries (e.g. Canada, the United States and Germany), either measures are solely applied at regional/state level or there are additional measures at that level of government. Local authorities can also play an important role in setting requirements for buildings sector technologies, as they often have responsibility for the implementation (and sometimes the setting) of building codes. Most common are obligations for solar thermal water heating, which are in place for example in Barcelona in Spain, São Paulo in Brazil and Shenzhen in China. In Italy, 903 municipalities have set solar thermal obligations (Legambiente, 2015), while in San Francisco a solar obligation for new buildings from 2017 can be met either through solar thermal or solar PV.

Most countries have so far failed to develop policies that effectively target renewable heat deployment in industry. Some industrial sectors already use significant amounts of renewable heat, specifically biomass in sectors such as paper and pulp, and food and beverage. This often makes use of residues, wastes or co-products. However, there is still much unexploited potential for renewable heat in other sectors and for other technologies. Some countries' support programmes (France's Fonds Chaleur, Germany's Marktanreiz Programme, the UK RHI) include industry applications, but uptake has been limited. Industry also often receives exemptions from carbon/energy taxes (e.g. Germany, United Kingdom), thus making the economics of renewable heat applications more challenging. There is also need for support for further research and innovation to overcome technical challenges, especially in high-temperature applications.

Box 4.5 Renewable heat and energy efficiency: integrated solutions

Achieving the ambitious targets of the Paris climate agreement will require a combination of energy efficiency improvements and a switch to renewable energy. Together, they are expected to provide two-thirds of the emission reductions in the IEA 2°C Scenario (2DS), which aims to restrict global warming to 2°C, compared with a 4°C warming scenario based on current policies. With heat accounting for almost half of total final energy consumption and being mainly fossil fuel-based, major contributions will be needed from heat-related energy efficiency and renewable heat.

Heat demand levels are directly related to the level of energy efficiency. Large amounts of energy are being wasted globally owing to inefficient building envelopes, industrial processes and heating equipment. Energy efficiency is an important and cost-effective first step in heat decarbonisation. Indeed, in some cases such as new-build houses built to the passive house standard, the demand for heat can be reduced to close to zero. However, in most cases, high levels of performance in energy

Box 4.5 Renewable heat and energy efficiency: Integrated solutions (continued)

efficiency retrofit are difficult to achieve (e.g. listed buildings in urban areas where external insulation is not permitted and internal insulation may be undesirable because of space constraints) or can be very costly. Renewable heat provides solutions for decarbonising the heat demand that remains after energy efficiency improvements. Furthermore, in industry there will always be heat demand.

To find the most effective solutions, both in terms of costs and emissions reduction, it is therefore important for policy makers to develop integrated policy approaches. Such integrated approaches are already common in the buildings sector, where many countries have policies or instruments that support both energy efficiency and renewable heat solutions:

- Building energy codes for buildings often require both high levels of energy efficiency and a contribution from renewable heat (or connection to district heating), for example in Germany, Denmark, Israel[27] and South Africa.
- Many financial incentive programmes for building energy retrofits include both energy efficiency and renewable heat measures (e.g. Germany, France, the United States), sometimes offering higher levels of financial support when measures are combined (e.g. Germany).
- High energy and carbon taxes in Denmark, Sweden and Switzerland have incentivised high levels of energy efficiency and a switch to renewable heat (which has been tax-exempt). However, these have operated in parallel with regulatory measures (such as building standards and obligations to connect to district heating).

A combination of energy efficiency and heat demand is equally important for decarbonising industrial heat, but the industrial sector generally has received much less policy attention. There are some exceptions, such as the United Kingdom, which in 2015 developed a set of industrial decarbonisation and energy efficiency roadmaps for energy-intensive industrial sectors. In the European Union, the imposition of a carbon price on energy-intensive industries through the EU ETS in principle should encourage both energy efficiency and fuel switching to renewable energy. However, the effectiveness of the EU ETS has been undermined by the low carbon price.

Overall, both heat and energy efficiency face a complex and often overlapping set of economic and non-economic barriers, which can be addressed through policy intervention. While integrated solutions for energy efficiency and renewable heat are highly desirable, there is significant scope for improvement in most countries.

Policy developments in key heat markets

As discussed above, the European Union is the biggest renewable heat market globally, driven by the RED. As a result, policies in the European Union are among the most extensive and dynamic, as countries adjust them to ensure their RED compliance. In 2015, key EU markets strengthened their renewable heat support mechanisms, with Germany increasing financial support under its Marktanreiz incentive programme, France doubling the funding for its Fonds Chaleur, and the United Kingdom extending funding for the RHI to 2021. Spain introduced the new PAREER-CRECE programme, which provides grants for biomass and geothermal heat. Policy changes are continuing in 2016, with Portugal opening a new energy efficiency grant scheme that offers 60% grants for solar

[27] 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.

thermal installations. The Slovak Republic's new Green Homes programme includes grants for solar thermal and heat pumps. The Netherlands launched the renewable heat support scheme for buildings, which provides investment grants for heat pumps, biomass boilers and solar thermal.

Renewable heat policies also evolved elsewhere. China proposed new renewable heat targets for its draft 13th FYP. In the United States, the tax credit for solar thermal installations was extended to 2021. For ASHPs and biomass stoves, there was also an extension, but only until the end of 2016. Tax credits for GSHPs are also due to expire in 2016. Thailand's Alternative Energy Development Plan introduced a number of new renewable heat targets. Chile reintroduced tax credits for solar thermal systems in construction projects.

The remainder of this section focuses on developments and policies in three growing markets for renewable heat – China, Germany and the United Kingdom. Following this developments in the wider European Union are discussed, focusing in particular on countries that have already achieved high shares of renewable heat.

Country case study: China

China's largest cities are in climate zones that have cold winters, and in many cases also hot summers. As the country's population has become increasingly urbanised with higher levels of income, demand for heating and cooling has increased dramatically. Residential space heating demand (including electricity used for heating) increased from 8.3 EJ in 2007 to 11.8 EJ in 2014, an increase of 42%. The increase in industrial production (especially energy-intensive sectors such as iron and steel) also resulted in a large increase in industrial heat demand but detailed statistics are no available.

Space heating demand in China is increasingly being met by district heating systems. Around half of major cities have district heating systems, and heat produced by district heating systems has tripled in the last 20 years, now covering about one-quarter of residential heat demand (Gong and Werner, 2014). Heat supply in these systems is dominated by coal boilers and coal-fired co-generation plants. Currently, renewables contribute only around 1% to meeting commercial heat demand (i.e. mainly district heating systems) and 2% to overall heat demand (IEA, 2016a). Nevertheless, in the future, the extent of the district heating system in principle provides a good basis for heat decarbonisation and the integration of renewable heat sources. Some countries such as Denmark, Iceland and Sweden have achieved major heat decarbonisation through both extending district heating coverage and switching to renewables in district heating systems. China is already collaborating with these countries on district heating development, and there is some progress with integrating renewables sources at the local level. This is primarily driven by local air pollution concerns to which coal boilers make a major contribution.

The 12th FYP (2011-15) included several renewable heat targets:

- 400 million m^2 of solar water heaters collector surface.
- Geothermal heat (including heat pumps) to supply 1.2 million homes and 580 million m^2.
- 2 million solar cookers.

The solar collector surface target was achieved one year early based on available solar thermal capacity figures. For the other targets, no specific figures are available as to whether they have been achieved.

Solar thermal deployment for water heating has been a success story with rapid progress, with China having the world's largest installed capacity in solar thermal (309 GW_{th}). In cities, district heating systems do not supply hot water, and solar thermal provides a cost-effective option for hot water supply. There have been some subsidies for solar water heaters at times, but most of the growth has been achieved without central government intervention because of the low cost of the systems. There are also some local policies that support solar thermal. For example, Shenzhen requires all new homes to install solar water heaters.

In terms of geothermal, by the end of 2014 a total of 390 million m^2 of buildings were heated by either heat pumps or geothermal district heating, and the area served by geothermal district heating has increased 2.8 times since 2009 (Zheng et al., 2015). However, this is still a very small contribution to overall heat supply, accounting for around 1% of district heating supply.

The 13th FYP is expected to have new ambitious targets for solar thermal and geothermal, but these are yet to be confirmed. A particular policy challenge will be how to increase the supply of renewable heat in industry.

Country case study: Germany

The German *Energiewende* (energy transition) has to date mainly focused on electricity. However, as heat accounts for more than 50% of total final energy consumption in Germany and two-thirds of industrial energy consumption, longer-term CO_2 targets cannot be met without a major shift away from fossil fuels in heat.

In 2014, only 12.2% of heat production was from renewables, compared with 27% of electricity generation. This was a significant increase from only 6.3% of heat produced from renewables in 2004, although renewable electricity grew over the same time period by 246% (BMWi, 2016). There is a federal government target of 14% renewables in heat by 2020, which according to government projections is likely to be met. Currently, 87% of the renewable heat supplied is from biomass. Overall, only 6% of renewable heat is supplied through district heating systems. Compared with Denmark and Sweden, Germany has a relatively small share of buildings served by district heating networks that are 85% fossil fuel-based.

There is an *Energiewende* target for an "almost" climate-neutral buildings sector by 2050 that will require a major scaling-up of energy efficiency and renewable heat. There has been recognition by the federal government that more needs to be done to achieve the buildings target. In November 2015, it published a strategy for buildings that found that the target cannot be achieved under a "business as usual" scenario with current policies such as building codes and market incentive programmes. Industrial process heat, which accounts for one-quarter of total final energy consumption, has also received little policy attention.

There are two main policy instruments for promoting renewable heat in Germany – regulations for a certain share of renewable heat (mostly applied to new homes) and a financial support programme:

- Under the Federal Renewable Energies Heat Act (EEWärmeG), there is an obligation for a certain percentage of heat demand to be met by renewable energy in new-build properties. The actual percentage depends on technology chosen. The state of Baden-Württemberg has a separate regulation that requires that existing buildings have 15% of their heat supplied from renewable sources when a new heating system is installed. This is a rare example where renewable heat is mandatory in existing (rather than new-build) buildings. Compliance data is patchy, but generation from renewable sources has increased markedly since the law was introduced (solar thermal has increased by 66% and heat supply from heat pumps by 180% since 2008). However, the modernisation rate of heating systems has also dropped significantly.

- Under the Marktanreiz programme, EUR 300 million per year is made available for a variety of grants and low-interest loans to support renewable heat installations for small-scale and large-scale applications (including industry and in district heating). For residential buildings, there is a bonus for combining energy efficiency and renewable heat in renovation projects. Support for renewable heat was increased in 2015 to accelerate deployment. However, the overall sum is still only a fraction of the support for renewable electricity under the FIT, which in 2016 is expected to amount to EUR 22.9 billion.

Deployment figures for renewable heat installations supported by the Marktanreiz programme in the residential and commercial sector (excluding industry and district heating) (Table 4.9) show that despite increased support from April 2015, the total number of installations was lower in 2015 than in 2014, in particular for biomass. This is borne out by figures from the pellet industry, which reports 10% fewer installations of pellet boilers in 2015 compared with 2014 (DEPV, 2016). The industry suggests that the low price of heating oil has been a key factor in the slow growth of the biomass heating market.

Germany still expects to meet its 2020 renewable heat target, but considerable challenges remain to achieve its long-term energy and climate targets.

Table 4.9 Deployment supported under the Marktanreiz programme: residential and commercial sector installations

Number of installations	2014	2015
Solar thermal (small-scale)	22 000	16 300
Solar thermal (large-scale including process heat)	1 000	700
Biomass	28 000	16 400
Heat pumps	4 500	3 700
Total support	EUR 124 million (USD 137 million)	EUR 92 million (USD 102 million)

Sources: BAFA (2016), Report 2015/2016; BAFA (2015), Report 2014/2015.

Country case study: The United Kingdom

The United Kingdom had the lowest share of renewable heat in the EU28 in 2014 (most recent comparative data available) with only 4.5%[28] of heat consumption met by renewables. This increased to 5.6% in 2015, compared with a much larger share for electricity of 24.6% (BEIS, 2016a). Most of the heat in buildings is supplied by individual gas (75%) or oil (8%) boilers (CCC, 2015). This reflects the housing stock (much of which is composed of low-density single-family dwellings), extensive gas

[28] The 2014 figure was revised upward to 4.9% in the latest national statistics, but this has not yet been reflected in EU statistics since they will not be updated until 2017.

networks and low gas prices. District heating networks are very limited, supplying only about 2% of UK heat demand, primarily through natural gas boilers and small co-generation plants. Some small district heating schemes have recently deployed biomass boilers (e.g. Sheffield Road Flats in Barnsley).

The combination of the United Kingdom's target under the RED and the ambitious long-term GHG emission targets under the 2009 Climate Change Act have resulted in a greater government focus on renewable heat policy. Part of this effort has been to take a more strategic approach, with the publication of a heat strategy in 2012 and a follow-up paper in 2013 (DECC, 2013). Key aspects of this focused on buildings and industrial heat decarbonisation and the role of heat networks. Subsequently, the government set up a Heat Networks Delivery Unit, made some funding available for networks, and developed a set of industrial carbon reduction and energy efficiency roadmaps.

The centrepiece of the United Kingdom's approach has been the introduction of a long-term support programme for renewable heat, the RHI,[29] with payments based on heat generated. The Netherlands is the only other country identified that offers generation-based heat support, although heat has been included in the FIT initially developed for electricity, rather than the introduction of a dedicated scheme. The RHI was initially introduced for commercial and industrial applicants in 2011 and then extended to the domestic sector in 2014. The aim of the RHI is to incentivise the uptake of renewable heating technologies by providing an attractive rate of return to compensate for the higher investment costs of some renewable technologies, as well as other non-economic barriers. Payments under the non-domestic RHI are based on heat meter readings, while in the domestic sector, heat is not metered but deemed. In addition to the RHI, there are further support measures available at the devolved level in Scotland (e.g. zero-carbon loans for renewable heat and a district heating loan fund).

Thanks to a very thorough monitoring system for RHI deployment, the United Kingdom now has some of the best renewable heat deployment statistics available globally, covering technologies and sectors where they are deployed. Currently, installations within the non-domestic scheme are dominated by biomass boilers, with more than half of the capacity installed in agriculture, hotels and similar accommodation (Table 4.10).

Table 4.10 Key RHI statistics to end of August 2016

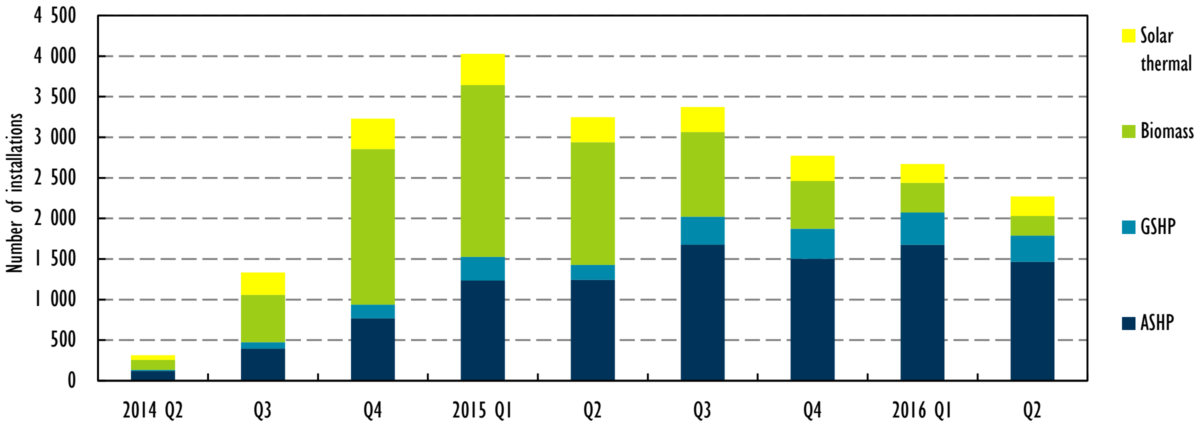
	Non-domestic scheme	Domestic scheme
Total number of accredited installations	15 340	50 927
Installed capacity (MW_{th})	2 616	Not available
Heat generated	9 992 GWh (since November 2011)	1 100 GWh (since April 2014)
Key technologies	Biomass boilers (94% of capacity)	Biomass boilers (56% of heat generated), heat pumps (42%)
Key sectors	Agriculture (32%), accommodation (21%), wood processing (8%)	Off-gas grid (73%), detached houses + bungalows (72%)
RHI budget April 2016 to April 2017	471 million pounds (GBP) (USD 719 million)	GBP 90 million (USD 137 million)

Sources: BEIS (2016b), Non-Domestic RHI and Domestic RHI Monthly Deployment Data: August 2016.

[29] The RHI currently operates only in England, Wales and Scotland. A separate scheme introduced in Northern Ireland was suspended in February 2016 for budgetary reasons.

RHI spending has been consistently below budget (CCC, 2016) and furthermore there has been a slowdown of RHI accreditations since the autumn of 2015 (Figure 4.13). This followed the degression of the biomass tariffs (20% of the domestic tariff and 15% for small commercial installations) from April 2015. This resulted in a sharp reduction in the deployment of biomass boilers under the scheme, without a corresponding increase from other technologies. The government is now consulting on increasing the tariff for heat pumps. However, it is also looking into excluding solar thermal from the scheme.

Figure 4.13 Domestic RHI accredited installations by technology, (2014-16)



Note: Excludes so-called legacy systems which were installed after the announcement of the plans to introduce the RHI and the actual launch of the domestic RHI.

Source: BEIS (2016b), Non-Domestic RHI and Domestic RHI Monthly Deployment Data: August 2016.

According to the UK Committee on Climate Change, while the RHI tariff payments address some of the economic barriers that renewable heat encounters, they do not tackle up-front cost barriers and there is currently little provision for approaches to tackle non-financial barriers such as low awareness. The Committee has identified the need for a policy package tackling key segments, addressing barriers, and linking support with energy efficiency policy, fuel poverty policy and infrastructure decisions. Additionally, for industry, new policies are needed to drive sustained uptake (CCC, 2016).

Regional focus: The European Union

Heating and cooling accounts for around half of EU energy consumption. Demand, primarily from the buildings and industry sectors, is predominantly served by fossil fuels and accounts for over two-thirds of EU natural gas imports (EC, 2016f). Therefore, achieving a transformation of the sector towards greater use of renewable energy in the region can deliver multiple benefits in terms of compliance with the European Union's 2020 and 2030 climate change and energy targets, supply diversification, and air quality improvements.[30]

Further uptake of renewable technologies is a key element of the European Union's first-ever strategy for heating and cooling, published in early 2016. In order to facilitate growth, the strategy

[30] Achieved by replacing inefficient solid fuel heating systems beyond their technical lifetimes with modern renewable alternatives.

indicates that the heating and cooling sector will be a core element of forthcoming reviews of the renewable energy, energy efficiency and energy performance of buildings directives (EC, 2016b). Within the *MTRMR 2016*, the status of heating and cooling in the European Union has been analysed using the latest available EC data for 2014,[31] in order to assess the differences in the relative maturity of renewable heat markets in different EU countries and causal factors for this. Heating and cooling is used in this section to reflect the fact that cooling is included in the data used. However, compared with heating, energy use for cooling accounts for a relatively small (<3%) share of overall EU heating and cooling demand (EC, 2016e), and the focus of this section is on heating.

Role of heating and cooling in compliance with the European Union's 2020 renewable energy targets

As of 2014, nine countries of the EU28 had already achieved their 2020 NREAP targets (not including the 10% target for renewable energy in transport). In all of these countries, the heating and cooling sector accounted for the largest percentage of renewable energy supplied across all end-use sectors i.e. heating and cooling, electricity, and transport, highlighting the importance of a well-developed renewable heat sector for compliance with member states' NREAP targets (Table 4.11).

In the EU28, heating and cooling accounts for the highest share of renewables in 13 countries, 6 of which met their overall NREAP target. By comparison, the share of renewables is highest in the electricity sector for 15 countries, with three having met their overall target. Through ranking EU28 countries in terms of their share of renewable energy in heating and cooling, it is shown that those countries with the largest gaps to bridge to meet their 2020 objectives have comparatively lower shares of renewables in heating and cooling. Of the EU28, France is 16th, Germany 22nd, the Netherlands 27th and the United Kingdom 28th.

Table 4.11 Percentage of total renewable consumption across all sectors used within heating and cooling (2014) for countries that have already achieved NREAP targets

Country	Heating and cooling share (2014) of renewable energy across all sectors
Bulgaria	60%
Croatia	61%
Czech Republic	65%
Estonia	85%
Finland	71%
Italy	49%
Lithuania	84%
Romania	61%
Sweden	52%
EU28	**50%**

Notes: For these countries, the share of renewable energy within each individual sector was highest for heating and cooling with the exception of Croatia, Italy and Romania, where the share of renewables was largest in the electricity sector. The above percentages reflect the share of renewable energy for heat of all renewable energy consumed across heat, electricity and transport.

Source: EC (2016c), *Energy from Renewable Sources*, http://ec.europa.eu/eurostat/web/energy/data/shares.

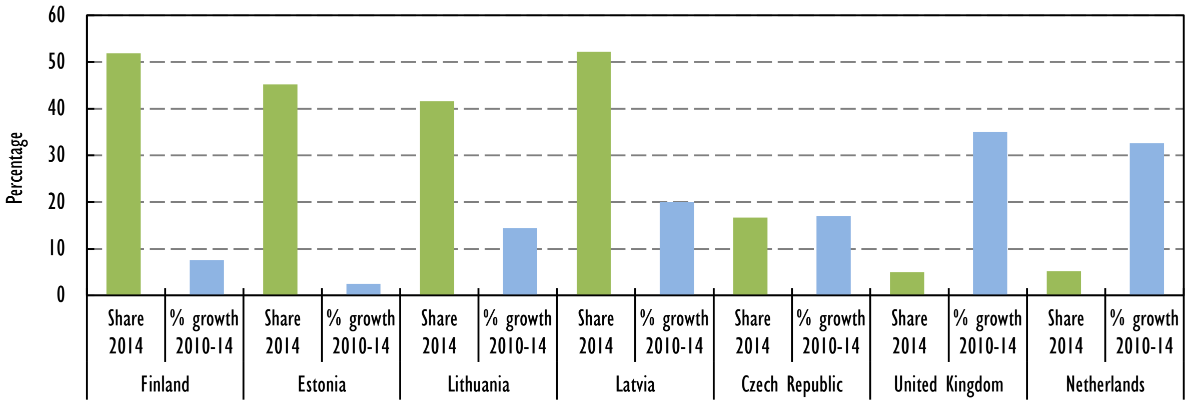
[31] Unless otherwise stated, data used are obtained from Eurostat (EC, 2016d).

Context for shares of renewables in the heating and cooling sector

Over the 2010-14 period, the percentage point share of renewable energy in the heating and cooling sector has increased in 27 member states of the EU28, with an average increase of 4 percentage points.[32] However, there are limitations to only considering the share of renewable energy in heating and cooling as a means of assessing progress, as higher or lower demand influences the renewable share figure. Through comparing energy consumption for heating and cooling in 2010 and 2014 and normalising for different weather conditions, overall in the EU28 energy demand for heating and cooling increased 7% in 2014. However, non-weather-related demand decreased in five of the EU28 over the same period. The reasons for lower non-weather-related demand differ by country, but among other considerations could be explained by increased energy efficiency in buildings, changes in industrial energy consumption and macroeconomic factors.

In addition to reviewing how the share of renewable energy in heating and cooling has developed in the EU28, it is also valuable to consider the percentage change in renewable heating and cooling supplied. This highlights where countries with lower levels of renewable heat are starting to make notable progress through the application of renewable heat policies (Figure 4.14). The United Kingdom, aided by the RHI scheme, increased renewable energy in heating and cooling by over 7 000 GWh from 2010 to 2014, representing an annual average growth rate of 4%. In the Netherlands, supported by the Stimulation of Sustainable Energy Production scheme, an increase of 3 500 GWh of renewable heating and cooling was delivered over the same period at an annual average growth rate of 3%.

Figure 4.14 Share of renewable energy in heating and cooling (2014) and percentage increase in renewable energy heating and cooling (2010-14) for selected EU28 countries



Source: EC (2016c), *Energy from Renewable Sources*, http://ec.europa.eu/eurostat/web/energy/data/shares.

The countries with comparatively higher shares of renewable energy in the heating and cooling sector already had established renewable heating markets prior to the adoption of NREAPs under the RED. In Sweden, which reached 68% renewable energy in heating and cooling in 2014, the transition to using renewable fuels in district heating began in the 1970s, with significant scale-up of their use in both district heating and co-generation during the following decade. The

[32] Over 2010-14 the share of renewable energy in heating and cooling did not increase in Romania.

scale-up of the renewable heat sector also benefited from a long-standing carbon taxation regime, while the integration of higher shares of renewable waste occurred from 2002 with a ban on landfilling combustible wastes.

Austria, with just under 33% renewable energy in heating and cooling in 2014, started deploying renewable alternatives to fossil fuels in the heating sector after the second oil crisis. Meanwhile, the Baltic States (see Figure 4.14 for shares of renewable energy in heating and cooling) have a legacy of district heating networks (initially coal- or oil-based) that provide infrastructure for the integration of bioenergy and waste. These cases highlight that the transformation of the heating and cooling sector to achieve high shares of renewable energy is a long-term process. Those countries that have only recently established measures to achieve this will require time to scale up.

Established renewable heat markets in these countries continue to grow as shown by percentage increases for renewable energy in heating and cooling (normalised for weather conditions) from 2010 to 2014 for Sweden (+6%), Finland (+6%), Denmark (+11%) and Austria (+8%). However, over the same period the most significant market growth occurred in countries in an earlier phase of scaling up renewable heat markets. Germany (+22%) led the way with deployment of renewable heat technologies aided by investment support, while the Netherlands, Hungary and the Czech Republic all grew by 16%. Furthermore, owing to energy diversification drivers and domestic biomass resource availability, Latvia (+10%), Lithuania (+8%) and Estonia (+14%) have scaled up consumption from an already high base.

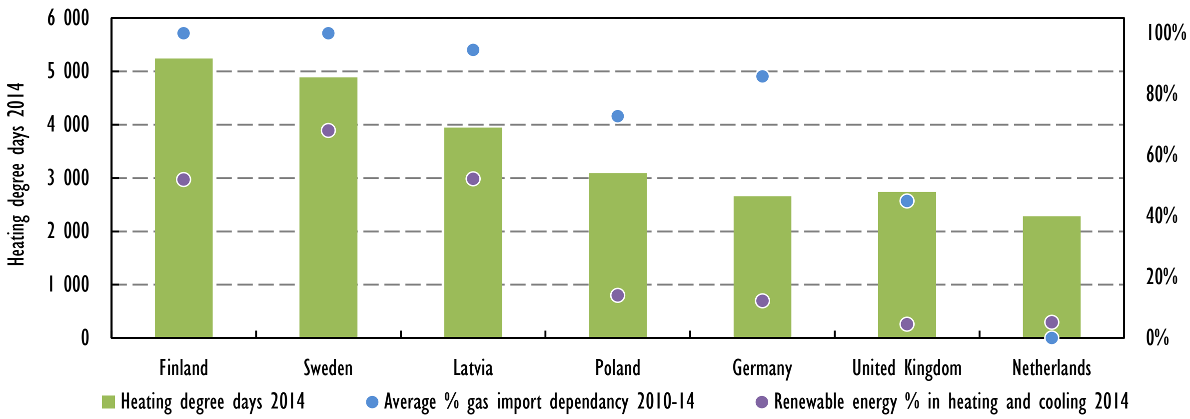
Solid biomass is the largest contributor to renewable heat production in the European Union, accounting for almost 850 TWh in 2013; while the contribution from biogas systems in the same year was around 30 TWh, with over half in Germany (EC, 2015). In 2014, 95 TWh was provided by heat pumps for the provision of renewable heating and cooling in countries with diverse climates. Both of these were above initial NREAP estimates. Solar thermal systems provided just over 24 TWh of renewable heating and cooling in 2014 (ESTIF, 2015).[33]

Key factors in achieving higher shares of renewable heat

Some of the strongest drivers for integrating higher shares of renewables in the heating sector exist in countries with high heat demand and security of supply considerations. As shown in Figure 4.15, countries with both high heat demand and gas import dependency have greater levels of renewable heat consumption compared with those with lower heat demand and indigenous natural gas resources. Many countries in Central and Southeast Europe and the Baltic States are dependent on a single supplier for most or all of their natural gas supply, therefore creating a strong incentive to diversify supply in the heating sector through expanding the use of renewable energy sources.

[33] EC data state 22 TWh in 2013, below the NREAP trajectory.

Figure 4.15 Heating degree days, 2014, renewable heating and cooling share, 2014, and average gas import dependency for selected EU28 countries (2010-14)



Note: Heating degree days express the severity of cold weather in a specific time period, taking into consideration the difference between outdoor temperature and room temperature.

Sources: EC (2016c), *Energy from Renewable Sources*, http://ec.europa.eu/eurostat/web/energy/data/shares; EC (2016b), *Energy Datasheets: EU-28 Countries*, https://ec.europa.eu/energy/en/statistics/country; EC (2016d), *Eurostat* (database), http://ec.europa.eu/eurostat.

District heating infrastructure and co-generation in buildings and prominent industrial sectors can facilitate the integration of renewable sources in the heating sector. In addition, the majority of energy demand in industry is for heating and cooling. Higher shares of low (<100°C) and medium (100°C to 400°C) temperature heat in the pulp and paper and food and tobacco industries, alongside the possibility to use process residues from these as fuels, facilitates the uptake of biomass and waste. The value of these factors is demonstrated in Table 4.12 through comparing countries with a range of renewable heat shares.

Table 4.12 Measures of district heating, co-generation and selected industries for selected EU28 countries

Country	RES heat share 2014 (%)	District heating (toe per capita)	RES in district heating (%)	Co-generation in total electricity generation (%)	RES & renewable waste in co-generation (%)	Share of pulp & paper and food & tobacco in Industry FEC (%)
Sweden	68.1	124	77	10	75	38
Finland	51.9	271	48	34	56	59
Germany	12.2	47	22	12	13	18
Poland	13.9	73	2	16	11	23
Netherlands	5.2	40	2	35	3	18
United Kingdom	4.5	39	2	6	7	17
EU28	**17.7**	**38**	**26**	**12**	**18**	**22**

Note: RES = renewable energy sources; toe = tonnes of oil equivalent; FEC = final energy consumption.

Source: EC (2016c), *Energy from Renewable Sources*, http://ec.europa.eu/eurostat/web/energy/data/shares; EC (2016b), Energy *Datasheets: EU-28 Countries*, https://ec.europa.eu/energy/en/statistics/country.

There is considerable scope to scale up the utilisation of renewable energy sources in co-generation and district heating in the European Union. Renewable heat sales, e.g. from district heating or co-generation plants, in the European Union increased just over 20% from 2010 to 2014. However, renewable sources accounted for under a quarter (by energy) of fuel used for heat sales. The majority (98%) of this came from biomass and renewable waste fuels. District heating accounted for 9% of EU heating in 2012, but this was primarily fuelled by gas (40%) and coal (29%) (EC, 2016a). As such there may be scope for the conversion of existing co-generation and district heating infrastructure from fossil to renewable fuels, as well as more widespread integration of large-scale heat pumps and solar thermal technologies into district heating networks.

Policy considerations

Growing renewable heat in the European Union will entail identifying solutions to ensure the replacement of existing heating systems, particularly the large proportion in the EU market operating beyond their technical lifetime, with renewable alternatives where feasible. Policies to ensure that renewable solutions are assessed and implemented for new buildings and during renovation are also necessary. Working with local authorities to encourage the roll-out of renewable district heating schemes, initiatives to encourage the identification and uptake of renewable solutions in the industry sector (especially for low-temperature heat loads), the utilisation of renewable fuels in co-generation where feasible, and maximising the uptake of renewable heating systems in the residential market segment will all be important facilitators of scaling up renewable heat in the European Union.

Overall, progress is being made in the heating and cooling sector towards EU renewable energy targets for 2020, with the nine countries that have already met their overall NREAP target benefiting from well-developed renewable heat markets. Progress is also evident in some countries that need to significantly scale up renewable heating and cooling deployment, but an evaluation of whether their policies and mechanisms are sufficient in meeting their renewable energy objectives in the heating and cooling sector may still be required.

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5. RENEWABLE ELECTRICITY POLICY TABLES

Table 5.1 Asia and Pacific

Asia and Pacific	Regulatory support				Economic support						
Country	Renewable energy law	Targets	Quotas/RPS	Auction schemes	Tradable green certificates	FIT/Feed-in premium	Capital grants and subsidies	Soft loans	Tax relief	Net metering	Carbon pricing
Australia	✔	●		■ ✓	✔	●	✔				✔
Bangladesh		✔		✔					✔		
India		✔✓	✔✓	✔✓	✔	✔	✓	✓	✔●	✔✓	✔
Indonesia		✔		●		●			✔		
Japan		●		■		●	✔		✔	✔	
Korea		✔	✔		✔	✓			✔		
Lao PDR*[1]		✔							✔		
Malaysia	✔	✔		●		●		✔	✔		
Mongolia	●	✔									
Myanmar		■							✔		
New Zealand		✔									✔
Pakistan		✔				●				⓪	
Philippines	✔	✔	⓪			●			✔	✔	
Singapore		✔					✔		✔		
Thailand		●		■		●	✔		✔		
Viet Nam		●				■		✔	✔		

Policy highlights

- **India** reduces accelerated depreciation incentive which will come into effect April 2017.
- **Indonesia** updated its FIT support for municipal waste projects and plans to launch tenders for geothermal in 2016 and 2017.
- **Japan** published *Long-Term Energy Supply and Demand Outlook* indicating estimated renewable generation by 2030. FIT was amended in 2016. Auctions for large scale solar PV projects from 2017.
- **Malaysia** adjusted its solar FIT levels and launched its first utility-scale solar tender in May 2016.
- **Mongolia** amended *State Policy on Energy for 2005-20* updating renewable energy target and aligning it with goals submitted in its INDC to COP21 in 2015.
- **Philippines** already allocated current FIT quota and new quota was announced in 2015 for onshore wind.
- **Thailand** adopted *Alternative Energy Development Plan for 2015-36* providing new long-term RE capacity targets. Utility-scale solar PV applications were halted in April 2016 and a new FIT and tender scheme were introduced for self-consumption and distributed projects.
- **Viet Nam** adopted *Renewable Energy Development Strategy 2016-30* and adjusted *National Power Development Plan 7* increasing long-term renewable energy targets.

Notes: ✔ = national-level policy; ✓ = state/provincial-level policy, ● = recently updated / to be phased out, or closed to new applicants, ⓪ = recently introduced; ■ – under review. For further information, refer to IEA/IRENA Policies and Measures Database for Renewable Energy: www.iea.org/policiesandmeasures/renewableenergy.

[1] **Lao PDR* = Lao People's Democratic Republic.

Table 5.2 Europe

Europe	Regulatory support				Economic support						
Country	Renewable energy law	Targets	Quotas/RPS	Auction schemes	Tradable green certificates	FIT/Feed-in premium	Capital grants and subsidies	Soft loans	Tax relief	Net metering	Carbon pricing
Austria	✔	✔				✔	✔		✔		
Belgium		✔	✔✓		✔✓		✔✓			✓	
Denmark	✔	✔	✔	●		✔	✔	✔	✔	✔	
Estonia		✔		⓪		●	✔		✔		
Finland	✔	✔				● ▶	✔				
France	✔	●		⓪		⓪	✔	✔	✔		
Germany	●	✔		⓪		●	●	●	✔		
Greece	■	✔		■		■	✔		✔	✔	
Hungary		✔		⓪		●	✔				
Ireland		✔				■			✔		
Italy	✔	✔		●		✔			✔	✔	
Netherlands		✔		⓪		●		✔	✔	✔	
Norway		●	▶		▶		✔				✔
Poland	⓪	✔	▶	⓪ ●	▶		●			⓪	
Portugal		✔									
Slovak Republic	✔	✔				✔	✔		✔		
Slovenia		✔				✔	✔	✔		⓪	
Spain		✔		⓪							
Sweden		✔	✔		✔		✔		✔		✔
Switzerland		✔				✔	✔				
Turkey	✔	✔				●					
United Kingdom		✔	▶	●	▶	■		✔	✔		✔

Policy highlights

- **Estonia** modified its FIP scheme introducing a strike price subjected to newly created tenders.
- **Finland** decreased FIP tariffs and brought forward closure of FIP support to November 2017 for wind projects.
- **France** introduced new FIP support where contracts are awarded either through tendering process or directly depending on the project size of the PV plant.
- **Germany** adopted an EEG amendment which will enter into force in January 2017. The reform introduced auctions for large-scale bioenergy, onshore wind, offshore wind and solar PV projects.
- **Greece** is currently working on extensive RE and electricity market reform.
- **Hungary** adopted auction system combined with FIP support to be introduced from 1 January 2017.
- **Ireland** closed FIT (REFIT 2 & 3) for new applications at the end of 2015.
- **Netherlands** increased its 2016 SDE+ budget from EUR 1bn to EUR 9bn. In mid-2015 the *Offshore Wind Energy Act* came into force introducing an auction scheme for offshore wind projects.
- **Slovenia** adopted decree on self-supply of electricity from RE sources regulating net metering.
- **Turkey** changed the regulation for un-licensed solar PV projects.

Notes: ✔ = national-level policy; ✓ = state/provincial-level policy, ● = recently updated, ▶ = to be phased out, or closed to new applicants, ⓪ = recently introduced; ■ – under review. For further information, refer to IEA/IRENA Policies and Measures Database for Renewable Energy: www.iea.org/policiesandmeasures/renewableenergy.

Table 5.3 North America

North America	Regulatory support				Economic support						
Country	Renewable energy law	Targets	Quotas/RPS	Auction schemes	Tradable green certificates	FIT/Feed-in premium	Capital grants and subsidies	Soft loans	Tax relief	Net metering	Carbon pricing
Canada	✓	✓	✓	⓪		✓	✔		✔	✓	✓⓪
Mexico	✔	□	✔	⓪	⓪		✔		✔	✔	✔
United States	✓	✓	✓	✓	✓	✓	✓	✔	□	✓	✓

Policy highlights

- **Canadian** province Alberta introduced an auction for large-scale onshore wind and solar projects.
- **Mexico** introduced and implemented its first clean energy certificates and energy auction .
- **United States** extended the ITC and PTC for renewable technologies. For solar PV and wind a phase-out schedule was introduced. Clean Power Plan was under legal challenges at the time of the publication.

Table 5.4 Latin America [2]

South America	Regulatory support				Economic support						
Country	Renewable energy law	Targets	Quotas/RPS	Auction schemes	Tradable green certificates	FIT/Feed-in premium	Capital grants and subsidies	Soft loans	Tax relief	Net metering	Carbon pricing
Argentina	□	□		⓪					□		✔
Brazil		✔		□			✔	✔	✔	✔	
Chile	✔	□	✔	✔			✔		✔	✔	
Colombia	□	✔							□	✔	
Costa Rica		✔		✔					✔	✔	
Honduras				✔		✔			✔		
Panama	✔	✔		✔					✔	✔	
Paraguay		✔							✔		
Peru			✔	✔					✔		
Uruguay	✔	✔		✔		✔			✔	✔	

Policy highlights

- **Argentina** enacted new *Renewable Energy Law* in October 2015 establishing new targets until 2025 and an auction system.
- **Brazil** updated rules guiding renewable energy auctions.
- **Chile** adopted *2050 Energy Roadmap* outlining long-term RE targets.
- **Colombia** updated its *Renewable Energy Law* establishing accelerated depreciation and other tax exemptions.

Notes: ✔ = national-level policy; ✓ = state/provincial-level policy, ● = to be phased out, or closed to new applicants, ⓪ = recently introduced; ■ – under review. For further information, refer to IEA/IRENA Policies and Measures Database for Renewable Energy: www.iea.org/policiesandmeasures/renewableenergy.

[2] Latin America and Caribbean region excludes Mexico which is included in North America.

Table 5.5 Middle East and North Africa (MENA)

MENA	Regulatory support				Economic support						
Country	**Renewable energy law**	**Targets**	**Quotas/RPS**	**Auction schemes**	**Tradable green certificates**	**FIT/Feed-in premium**	**Capital grants and subsidies**	**Soft loans**	**Tax relief**	**Net metering**	**Carbon pricing**
Algeria	✔	☐				☐			✔		
Egypt	✔	✔	✔	✔		✔			☐	✔	
Iran		✔	✔			✔					
Iraq		✔		⓪							
Israel		✔	✔			✔			✔	✔	
Jordan	✔	✔		✔		✔			✔	✔	
Lebanon		✔						✔		✔	
Morocco	✔	✔		✔			✔		✔	☐	
Saudi Arabia		☐		✔							
Tunisia	✔	✔					✔	✔	✔	✔	
United Arab Emirates		✔✓		✔			✔				

Policy highlights

- **Algeria** updated its *Renewable Energy and Energy Efficiency Development Plan for 2015*
- **Egypt** amended its *Investment Law* in 2015 allowing for number of tax incentives for renewable energy investors. Egypt is concluding it's BOO contracts auction round that was launched in 2015.
- **Morocco** passed a law enabling IPPs to connect to the high voltage grid to sell their excess production
- **Saudi Arabia** adopted *Vision 2030* strategy aiming to install 9.5 GW of renewable energy capacity by 2030.

Table 5.6 Eurasia

Eurasia	Regulatory support				Economic support						
Country	**Renewable energy law**	**Targets**	**Quotas/RPS**	**Auction schemes**	**Tradable green certificates**	**FIT/Feed-in premium**	**Capital grants and subsidies**	**Soft loans**	**Tax relief**	**Net metering**	**Carbon pricing**
Armenia		✔				✔	✔	✔			
Azerbaijan		✔									
Belarus		✔				✔			✔		
Kazakhstan		✔				✔	✔		✔		
The Russian Federation		✔	☐	✔							
Tajikistan	✔	✔							✔		
Ukraine		✔				☐			✔		

Policy highlights

- **The Russian Federation** continues to implement renewable energy auctions.
- **Ukraine** simplified land permitting procedures; removed local content requirement and replaced it with additional bonus paid on top of FIT levels. Quarterly FIT adjustments are indexed to Euro.

Notes: ✔ = national-level policy; ✓ = state/provincial-level policy, ● = recently updated, to be phased out, or closed to new applicants, ⓪ = recently introduced; ■ – under review. For further information, refer to IEA/IRENA Policies and Measures Database for Renewable Energy: www.iea.org/policiesandmeasures/renewableenergy.

Table 5.7 Sub-Saharan Africa

Sub-Saharan Africa	Regulatory support				Economic support						
Country	Renewable energy law	Targets	Quotas/RPS	Auction schemes	Tradable green certificates	FIT/Feed-in premium	Capital grants and subsidies	Soft loans	Tax relief	Net metering	Carbon pricing
Angola							✔				
Cameroon		✔*							✔		
Ethiopia		✔							✔		
Ghana	✔	✔	■			■			✔	✔	
Kenya		✔				✔			✔	■	
Mauritius		✔		⓪		✔			✔		
Namibia						✔					
Niger		✔							✔		
Nigeria		✔		■		□			✔		
Senegal	✔	✔							✔		
South Africa	✔	✔		✔				✔	✔		■
Tanzania		✔		⓪		□	✔		✔		
Togo		✔									
Zambia				⓪		⓪	✔	✔	✔		
Zimbabwe		✔							✔		

Policy highlights

- **Cameroon** included a 25% of RES in electricity generation by 2035 in its INDC.
- **Mauritius** opened its first solar PV auction.
- **Nigeria** revised down FIT levels.
- **Tanzania** approved *Second Generation Framework for Small Power Projects* (< 10 MW) updating FIT for small hydropower and biomass. Tendering process was introduced for 1-10 MW of solar and wind projects.
- **Zambia** opened its first tender round to procure total of 100 MW of solar PV capacity. Second tender is scheduled to take place in late 2016. Tenders followed introduction of *Scaling Solar Programme* and FIT guidelines.

Notes: * = target included in the INDC; ✔ = national-level policy; ✓ = state/provincial-level policy, ● = recently updated, ≡ to be phased out or closed to new applicants, ⓪ = recently introduced; ■ = under review. For further information, refer to IEA/IRENA Policies and Measures Database for Renewable Energy: www.iea.org/policiesandmeasures/renewableenergy.

6. DATA TABLES

Table 6.1 Ethanol production (billion litres)

	2015	2016	2017	2018	2019	2020	2021	CAAGR 2015-21
World	**100.9**	**102.1**	**104.3**	**105.3**	**107.1**	**109.7**	**111.8**	**1.5%**
North America	57.8	58.9	58.8	57.8	57.2	57.0	57.0	-0.2%
Canada	1.7	1.8	1.7	1.6	1.5	1.5	1.5	-1.4%
United States	56.0	56.9	56.9	56.0	55.4	55.2	55.2	-0.2%
EU28	4.9	5.6	5.9	6.0	6.2	6.3	6.0	2.9%
France	0.9	0.9	1.0	1.0	1.1	1.1	1.1	3.1%
Germany	0.9	0.9	0.9	0.9	0.9	1.0	0.9	-0.4%
Eurasia	0.2	0.2	0.2	0.2	0.2	0.2	0.2	2.6%
Asia and Pacific	2.7	3.2	3.7	4.3	4.7	5.3	5.7	11.2%
ASEAN	1.6	1.8	2.0	2.3	2.4	2.7	2.9	8.9%
India	0.7	1.0	1.2	1.4	1.6	1.8	2.0	16.2%
Thailand	1.2	1.2	1.4	1.5	1.7	1.9	2.1	8.5%
China Region	2.7	3.2	3.2	3.3	3.4	3.5	3.6	4.0%
Latin America	32.0	30.5	31.8	32.7	34.2	36.2	38.2	2.5%
Argentina	0.8	1.0	1.0	1.1	1.1	1.1	1.1	3.8%
Brazil	29.7	28.0	29.1	30.0	31.5	33.5	35.4	2.5%
Africa	0.2	0.3	0.5	0.6	0.8	0.9	0.9	22.3%
Rest of world	0.5	0.5	0.5	0.5	0.5	0.5	0.5	2.0%

Notes: ASEAN = Association of Southeast Asian Nations. Production numbers by volume; to convert to energy adjusted production, bioethanol is assumed to have 2/3 of the energy content of gasoline.
Sources: IEA (2016a), *Oil Information* (database), www.iea.org/statistics/; IEA (2016b), *Monthly Oil Data Service (MODS) [May 2016]*, www.iea.org/statistics/; MAPA (2016), *Ministério da Agricultura – Agroenergia;* US EIA (2016a), *Petroleum & Other Liquids*.

Table 6.2 Biodiesel production (billion litres)

	2015	2016	2017	2018	2019	2020	2021	CAAGR 2015-21
World	**31.1**	**33.8**	**39.4**	**42.8**	**44.8**	**46.4**	**45.3**	**5.5%**
North America	5.1	6.1	6.7	7.2	7.5	7.7	7.7	6.2%
Canada	0.3	0.4	0.5	0.5	0.5	0.6	0.6	10.4%
United States	4.8	5.7	6.2	6.7	7.0	7.2	7.2	5.9%
EU28	12.2	12.5	14.1	14.9	15.2	15.5	13.7	1.7%
France	2.1	1.8	2.3	2.6	2.6	2.6	2.4	2.3%
Germany	2.9	3.0	3.4	3.4	3.4	3.5	3.0	0.4%
Eurasia	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0%
Asia and Pacific	5.9	7.0	8.4	9.6	10.2	10.8	11.4	9.8%
ASEAN	5.0	6.2	7.5	8.7	9.2	9.7	10.3	10.8%
Indonesia	1.7	3.0	3.8	4.8	5.2	5.5	5.9	19.6%
Malaysia	0.9	0.9	1.0	1.1	1.2	1.2	1.3	5.8%
Thailand	1.2	1.0	1.3	1.4	1.5	1.6	1.7	4.2%
China Region	0.5	0.6	0.7	0.7	0.8	0.8	0.9	10.8%
Latin America	7.0	7.0	8.8	9.6	10.4	10.8	10.8	6.4%
Argentina	2.2	2.3	3.3	3.4	3.4	3.4	3.4	6.7%
Brazil	3.9	3.8	4.5	5.2	5.9	6.2	6.2	7.0%
Africa	0.3	0.3	0.4	0.4	0.4	0.4	0.4	6.3%
Rest of world	0.3	0.3	0.3	0.3	0.3	0.3	0.3	2.8%

Notes: Production numbers by volume; to convert to energy adjusted production, biodiesel is assumed to have 90% of the energy content of diesel.
Sources: IEA (2016a), *Oil Information* (database), www.iea.org/statistics/; IEA (2016b), *Monthly Oil Data Service (MODS) [May 2016]*, www.iea.org/statistics/; MAPA (2016), *Ministério da Agricultura – Agroenergia;* US EIA (2016a), *Petroleum & Other Liquids*.

Table 6.3 Total renewable electricity capacity (GW)

	2015	2016	2017	2018	2019	2020	2021	CAAGR 2015-21
World	1 969	2 117	2 251	2 382	2 518	2 660	2 795	**6.0%**
North America	333	354	372	392	417	445	468	5.8%
Canada	94	96	98	100	102	105	107	2.2%
Mexico	18	19	20	23	26	30	33	10.9%
United States	221	239	254	270	288	310	328	6.8%
Asia and Pacific	293	322	354	379	404	430	455	7.6%
Australia	18	19	21	22	24	26	27	7.0%
India	82	92	105	117	131	145	158	11.4%
Indonesia	9	9	10	10	11	12	13	7.4%
Japan	91	101	111	116	118	121	123	5.1%
Korea	13	14	16	17	19	21	22	9.2%
Thailand	9	10	11	12	14	15	15	9.6%
Europe	517	538	559	577	597	619	637	3.5%
Austria	18	19	19	20	20	21	21	2.0%
Belgium	8	8	8	9	10	10	11	5.9%
Czech Republic	5	5	5	5	5	6	6	0.5%
Denmark	7	8	8	9	9	10	10	5.2%
Estonia	1	1	1	1	1	1	1	4.9%
Finland	6	7	7	7	8	8	9	6.4%
France	44	46	48	51	54	58	61	5.7%
Germany	105	111	116	120	124	129	133	4.0%
Greece	8	8	8	8	8	8	9	0.7%
Hungary	1	1	1	1	1	1	1	2.7%
Iceland	3	3	3	3	3	3	3	0.5%
Ireland	3	3	4	4	4	5	5	7.7%
Italy	55	55	56	57	58	58	59	1.3%
Netherlands	6	7	9	10	10	12	13	12.5%
Norway	32	33	33	33	34	34	35	1.1%
Poland	9	9	10	10	10	11	11	3.6%
Portugal	12	13	13	14	14	14	14	2.6%
Slovak Republic	3	3	3	3	3	3	3	0.8%
Slovenia	2	2	2	2	2	2	2	5.5%
Spain	52	52	52	52	52	52	52	0.3%
Sweden	27	28	28	29	30	30	31	2.6%
Switzerland	16	16	17	18	18	19	20	3.9%
Turkey	32	34	37	39	41	44	46	6.5%
United Kingdom	33	36	39	41	43	47	48	6.6%
Latin America	192	202	211	222	230	238	245	4.2%
Argentina	13	13	14	14	14	15	15	2.4%
Brazil	112	120	125	132	137	141	145	4.4%
Chile	9	10	11	12	13	14	15	8.5%
Uruguay	2	2	2	3	3	3	3	9.1%
China Region	502	562	610	658	707	756	807	8.2%
MENA	25	27	29	32	35	39	43	9.4%
Egypt	4	4	4	4	5	6	7	10.4%
Jordan	0	0	1	1	1	1	2	47.3%
Morocco	3	3	3	4	4	5	5	12.0%
Saudi Arabia	0	0	0	0	0	1	1	83.6%
United Arab Emirates	0	0	0	1	1	1	2	56.9%
Sub-Saharan Africa	28	32	36	40	44	49	53	11.0%
Kenya	2	2	2	2	2	3	3	10.1%
South Africa	5	6	8	9	10	11	12	16.6%
Eurasia	78	79	80	81	83	85	86	1.6%
Russia	51	52	52	53	53	53	53	0.6%
Ukraine	7	7	7	7	7	7	8	2.2%

Notes: MENA = Middle East and North Africa; GW = gigawatt. Capacity data are generally presented as cumulative installed capacity, irrespective of grid-connection status. Renewable electricity capacity includes capacity from bioenergy, hydropower (including pumped storage), onshore and offshore wind, solar PV, solar CSP, geothermal, and ocean technologies. Grid-connected solar PV capacity (including small-distributed capacity) is counted at the time that the grid connection is made, and off-gird solar PV systems are included at the time of the installation. Please refer to regional definitions in the glossary. Specific sources are referenced where data for individual technologies are presented in previous chapters.

Table 6.4 Total renewable electricity generation (TWh)

	2015	2016	2017	2018	2019	2020	2021	CAAGR 2015-21
World	**5 660**	**5 974**	**6 315**	**6 649**	**6 989**	**7 326**	**7 672**	**5.2%**
North America	1 043	1 108	1 165	1 221	1 281	1 338	1 412	5.2%
Canada	414	422	431	440	445	450	458	1.7%
Mexico	47	49	53	58	69	79	88	10.8%
United States	581	638	681	724	766	809	866	6.9%
Asia and Pacific	714	786	861	925	984	1043	1101	7.5%
Australia	32	37	40	44	48	51	54	9.2%
India	218	235	258	284	310	337	363	8.9%
Indonesia	34	35	36	38	40	44	47	5.7%
Japan	171	189	206	220	228	235	243	6.0%
Korea	16	21	24	28	31	34	38	15.8%
Thailand	17	21	24	26	29	32	34	11.8%
Europe	1277	1326	1376	1426	1488	1540	1589	3.7%
Austria	51	56	57	57	59	60	61	3.1%
Belgium	15	15	16	18	20	21	24	7.9%
Czech Republic	10	11	11	11	11	11	11	1.6%
Denmark	17	18	20	21	22	23	24	5.6%
Estonia	2	2	2	2	2	2	2	5.6%
Finland	30	29	31	32	34	35	37	3.4%
France	94	102	106	110	116	121	131	5.6%
Germany	202	205	216	227	235	244	253	3.8%
Greece	14	14	14	15	15	15	15	1.2%
Hungary	3	4	4	4	4	4	4	4.4%
Iceland	19	18	18	18	19	19	19	0.0%
Ireland	8	8	9	10	11	12	13	8.4%
Italy	111	119	120	121	123	124	126	2.1%
Netherlands	14	15	17	21	23	26	32	15.6%
Norway	142	140	141	143	143	144	145	0.4%
Poland	23	30	31	33	47	52	42	10.2%
Portugal	25	30	31	32	33	33	33	4.6%
Slovak Republic	6	7	7	7	7	7	7	2.1%
Slovenia	5	5	6	6	6	6	7	5.9%
Spain	100	108	108	109	109	110	110	1.5%
Sweden	101	92	94	95	97	99	102	0.2%
Switzerland	43	42	44	45	46	47	49	2.1%
Turkey	84	94	102	109	115	122	129	7.5%
United Kingdom	86	89	96	104	112	120	130	7.2%
Latin America	794	824	855	895	928	964	991	3.8%
Argentina	45	45	46	46	47	48	51	1.9%
Brazil	430	444	466	489	509	533	548	4.1%
Chile	31	32	33	36	40	42	45	6.5%
Uruguay	10	11	11	12	12	13	13	4.8%
China Region	1 397	1 482	1 589	1 688	1 791	1 897	2 006	6.2%
MENA	45	50	54	59	65	72	80	10.1%
Egypt	16	16	17	18	19	21	23	6.2%
Jordan	0	1	1	1	2	2	3	54.6%
Morocco	5	5	6	7	8	9	10	14.2%
Saudi Arabia	0	0	0	0	1	1	2	85.8%
United Arab Emirates	0	0	1	1	2	3	3	51.5%
Sub-Saharan Africa	119	126	140	156	169	185	202	9.3%
Kenya	9	9	10	12	13	14	15	8.8%
South Africa	11	14	18	22	25	28	32	18.9%
Eurasia	271	273	275	278	282	287	291	1.2%
Russia	188	189	190	190	191	192	193	0.5%
Ukraine	15	15	15	16	16	17	17	2.5%

Notes: TWh = terawatt hour. Generation data refer to gross electricity production and include electricity for own use. Renewable electricity generation includes generation from bioenergy, hydropower (including pumped storage), onshore and offshore wind, solar PV, solar CSP, geothermal, and ocean technologies. Generation from bioenergy includes generation from solid, liquid and gaseous biomass (including co-fired 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, 2015 generation data are based on IEA statistics published in *Renewables Information 2016*.

GLOSSARY

Regional and country groupings

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.

Eurasia:

Armenia, Azerbaijan, Belarus, Bosnia and Herzegovina, Georgia, Gibraltar, Kazakhstan, Kosovo, Kyrgyz Republic, Moldova, Russian Federation, Tajikistan, Turkmenistan, Ukraine and Uzbekistan.

Europe:

Austria, Albania, Belgium, Bulgaria, Croatia, Cyprus, 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, Slovak Republic, Slovenia, Spain, Sweden, Switzerland, Turkey and United Kingdom.

Middle East and North Africa (MENA):

Algeria, Bahrain, Egypt, Iran, Iraq, Israel, Jordan, Kuwait, Lebanon, Libya, Morocco, Oman, Qatar, Saudi Arabia, Syria, Tunisia, United Arab Emirates and Yemen.

North America

Canada, Mexico and the United States.

Latin America

Latin America excludes Mexico which is included in North America. Argentina, Bolivia, Brazil, Chile, Colombia, Costa Rica, Cuba, the Dominican Republic, Ecuador, El Salvador, Guatemala, Haiti, Honduras, Jamaica, Nicaragua, Panama, Paraguay, Peru, Trinidad and Tobago, Uruguay, Venezuela and other Latin American countries (Antigua and Barbuda, Aruba, Bahamas, Barbados, Belize, Bermuda, British Virgin Islands, Cayman Islands, Dominica, Falkland Islands (Malvinas), French Guyana, Grenada, Guadeloupe, Guyana, Martinique, Montserrat, Netherlands Antilles, Saint Kitts and Nevis, Saint Lucia, Saint Pierre et Miquelon, St. Vincent and the Grenadines, Suriname and Turks and Caicos Islands).

Sub-Saharan Africa:

Angola, Benin, Botswana, Cameroon, Congo, Democratic Republic of Congo, Côte d'Ivoire, Eritrea, Ethiopia, Gabon, Ghana, Kenya, Mauritius, Mozambique, Namibia, Niger, Nigeria, Senegal, South Africa, South Sudan, Sudan, United Republic of Tanzania, Togo, Zambia, Zimbabwe and other African countries (Burkina Faso, Burundi, Cape Verde, Central African Republic, Chad, Comoros, Djibouti, Equatorial Guinea, Gambia, Guinea, Guinea-Bissau, Lesotho, Liberia, Madagascar, Malawi, Mauritania, Rwanda, Sao Tome and Principe, Seychelles, Sierra Leone, Somalia, Swaziland, Uganda).

Abbreviations and acronyms

2DS	2°C Scenario
AD	accelerated depreciation
ANP	National Petroleum Agency (Brazil)
ASHP	air source heat pump
ASTM	American Society of Testing and Materials
BAFA	Federal Office for Economic Affairs and Export Control (Germany)
BNDES	Brazilian National Development Bank
BOS	balance-of-system
CAAGR	compound annual average growth rate
CAPEX	capital expenditure
CCGT	combined-cycle gas turbine
CfD	Contracts for Difference
CI	carbon intensity
CNREC	China National Renewable Energy Centre
CO_2	carbon dioxide
COP	coefficient of performance
COP21	21st Conference of Parties
CPO	crude palm oil
CPP	Clean Power Plan (United States)
CSP	concentrating solar power
Defstand	Defence Standard (United Kingdom)
DSHC	direct sugars to hydrocarbons
EBRD	European Bank for Reconstruction and Development
EC	European Commission
EFTA	European Free Trade Association
EfW	energy for waste
EGS	enhanced geothermal systems
EOR	enhanced oil recovery
EPC	engineering, procurement and construction
EPCO	electricity power company
ESCO	energy service company
EU	European Union
EU ETS	European Union Emissions Trading Scheme
EVSE	electric vehicle supply equipment
FAME	fatty acid methyl esters
FIP	feed-in premium
FIT	feed-in tariff

FLH	full load hours
FQD	Fuel Quality Directive (EU)
FYP	Five-Year Plan (China and India)
GBI	generation-based incentive
GDP	gross domestic product
GHG	greenhouse gas
GSHP	ground source heat pump
HVO	hydrotreated vegetable oil
IEA	International Energy Agency
IFC	International Finance Corporation
INDC	Intended Nationally Determined Contribution
IPCC	Intergovernmental Panel on Climate Change
IPP	independent power producer
IRENA	International Renewable Energy Agency
IRS	Internal Revenue Service
ITC	investment tax credit (US)
JNNSM	Jawaharlal Nehru National Solar Mission (India)
LCF	Levy Control Framework (United Kingdom)
LCFS	Low Carbon Fuel Standard (United States)
LCOE	levelised cost of electricity
LCR	local content requirements
LNG	liquefied natural gas
LPG	liquefied petroleum gas
Mono-Si	monocrystalline silicon
MTRMR	*Medium-Term Renewable Energy Market Report*
NDC	Nationally Determined Contribution
NEA	National Energy Administration (China)
NREAP	National Renewable Energy Action Plan (EU)
O&M	operation and maintenance
OECD	Organisation for Economic Co-operation and Development
PHEV	plug-in hybrid electric vehicle
PPA	power purchase agreement
PPP	public private partnership
PSP	pumped storage plant
PTC	production tax credit (US)
PV	photovoltaic
RE	renewable energy
RED	Renewable Energy Directive (EU)
RHI	Renewable Heat Incentive
RO	Renewables Obligation
RPO	Renewable Purchase Obligation
RPS	Renewable Portfolio Standard
SBP	Sustainable Biomass Partnership (EU)
SE4ALL	Sustainable Energy for All
SPF	seasonal performance factor
STE	solar thermal electricity

TPES	total primary energy supply
UNFCCC	United Nations Framework Convention on Climate Change
US DOE	United States Department of Energy
US EPA	United States Environmental Protection Agency
VoST	value of solar tariff
VRE	variable renewable energy
WACC	weighted average cost of capital
WEO	*World Energy Outlook*
WTO	World Trade Organization

Currency codes

AUD	Australian dollar
BRL	Brazilian real
CAD	Canadian dollar
CNY	Chinese Yuan renminbi
EUR	euro
GBP	British pound
INR	Indian rupee
JPY	Japanese yen
MAD	Moroccan dirham
USD	United States dollar
ZAR	South African rand

Units of measure

CF	cubic feet
EJ	exajoule
GW	gigawatt, 1 gigawatt equals 10^9 watt
GWh	gigawatt-hour, 1 gigawatt hour equals 10^9 watt hours
GW_{th}	gigawatt thermal
Ktoe	thousand tonnes of oil-equivalent
kW	kilowatt, 1 kilowatt equals 10^3 watt
kWh	kilowatt hour, 1 kilowatt hour equals 10^3 watt hours
kW_{th}	kilowatt thermal
kJ	kilojoule
m^2	square metre
MBtu	million British thermal units
Mt	megatonne
Mtoe	million tonnes of oil-equivalent
MW	megawatt, 1 megawatt equals 10^6 watt
MW_{th}	megawatt thermal
MWh	megawatt hour, 1 megawatt hour equals 10^6 watt hours
t CO^2	tonne of CO^2
TJ	terajoule
toe	tonnes of oil-equivalent
TWh	terawatt hour, 1 terawatt hour equals 10^{12} watt hours
W	watt

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