RENEWABLE ENERGY

MARKETS AND PROSPECTS BY TECHNOLOGY

INFORMATION PAPER

Adam Brown, Simon Müller, and Zuzana Dobrotková

2011 November

International Energy Agency

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This information paper was drafted by the Renewable Energy Division. It is one of three information papers that complement the IEA publication Deploying Renewables 2011: Best and Future Policy Practice, *providing more detailed data and information. This paper is published under the authority of the Energy Markets and Security (EMS) Directorate and may not reflect the views of individual IEA member countries. For further information, please contact Simon Müller, Renewable Energy Division, at: simon.mueller@iea.org*

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INTERNATIONAL ENERGY AGENCY

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Context

This information paper accompanies the IEA publication *Deploying Renewables 2011: Best and Future Policy Practice* (IEA, 2011a). It provides more detailed data and analysis and explores the markets, policies and prospects for a number of renewable energy (RE) technologies. It is intended to complement the main publication. Two other information papers are also available. One focuses on the markets, policies and prospects of RE technologies by region (Müller, Marmion and Beerepoot, 2011), and the other analyses policies for deploying renewables (Müller, Brown and Ölz, 2011).

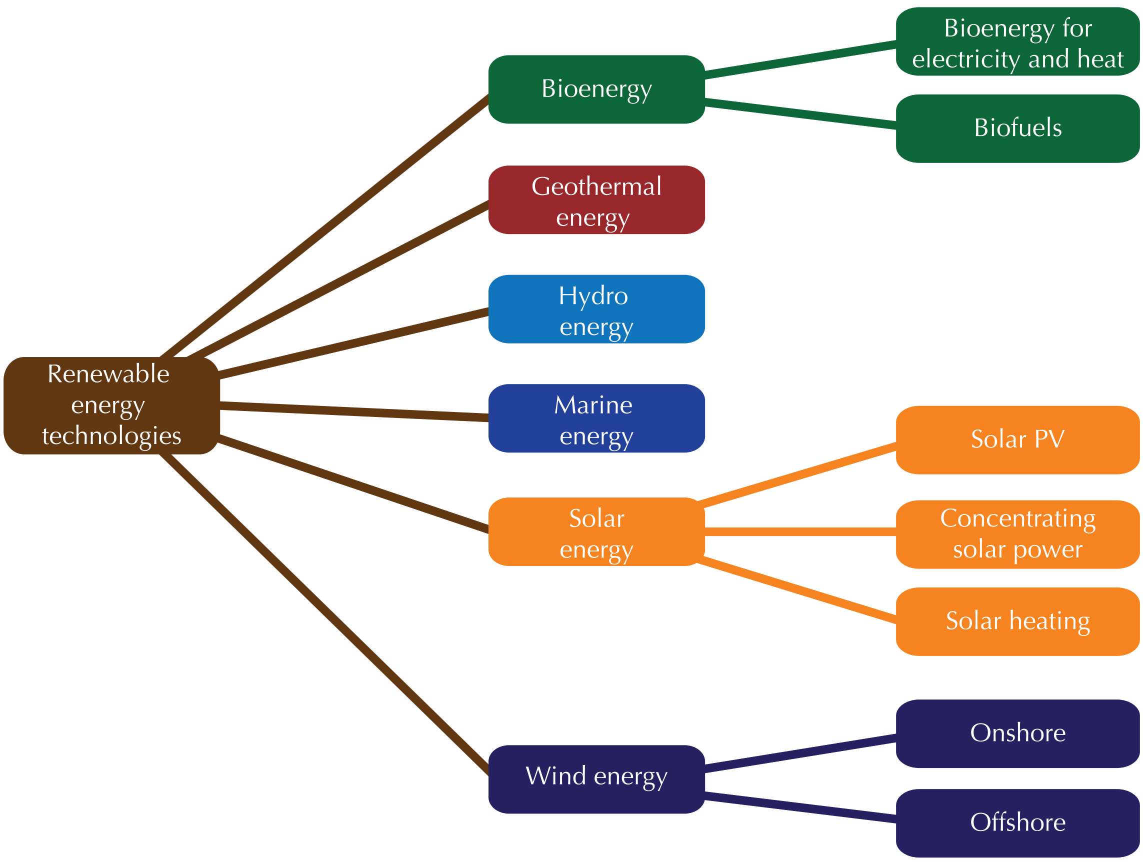
Introduction

This information paper accompanies the IEA publication *Deploying Renewables 2011: Best and Future Policy Practice* (IEA, 2011a). It provides more detailed data and analysis on the different renewable energy technologies (RE technologies) and is intended to complement the main publication. Two other information papers are also available. One focuses on the strategic drivers for RE support policies and policy principles (Müller, Brown and Ölz, 2011), and the other explores the markets, policies and prospects of RE technologies by region (Müller, Marmion and Beerepoot, 2011).

Different RE technologies and resources exist for electricity, heat and biofuel production. These technologies are at different stages in their evolution and can be categorised according to their position along the development cycle, where the focus is principally on one of the following:

- R&D to show that the technology works and to improve performance and costs;
- demonstration of the technology at, or close to, full commercial scale; or
- commercial deployment of the technology, available with commercial performance guarantees.

Figure 1.1 Selected renewable energy sources and technologies



Source: Unless otherwise indicated, all material for figures and tables derives from IEA data and analysis.

Key point: Different renewable energy technologies and resources exist for electricity, heat and biofuel production.

Investors are sensitive to the maturity and track record of technologies, because these factors signal the technical and commercial risks likely to be associated with projects. The economic competitiveness of the technologies, when compared to their fossil fuel-based alternatives, is, of course, also critical. Technologies can be technically well established but still be expensive compared with alternatives. Also, as discussed elsewhere (IEA, 2011a), bridging this potential competitiveness gap as cost-effectively as possible has been a major focus for recent renewables policy.

This paper provides a discussion of ten technology areas: bioenergy for electricity and heat, biofuels, geothermal energy, hydro energy, ocean energy, solar energy (solar photovoltaics, concentrating solar power, and solar heating), and wind energy (onshore and offshore) (Figure 1.1).[1]

Each technology discussion includes:

- the current technical and market status;
- the current costs of energy production and cost trends;
- the policy environment;
- the potential and projections for the future; and
- an analysis of the prospects and key hurdles to future expansion.

A dedicated analysis of the 2030 RE potential for all 56 focus countries was carried out for this publication (IEE [Institute of Energy Economics], 2010). Caution is warranted when interpreting the data on potentials. Resource estimates were not reliably available for all countries. As a result, there is a high degree of uncertainty attached to the potential estimates.[2] The assessment is based on a consideration of the possible build out of RE technologies until 2030, taking into account integration and sustainability constraints. Economic factors and competition between RE technologies are not accounted for.

[1] Note that the authors found that in some cases it is preferable to discuss technologies by energy *sector* (*e.g.* bioenergy). In other cases, a segmentation of the presentation according to *sub-technology* was found to be more advantageous (*e.g*. wind energy).

[2] For example, it is well known that a higher spatial resolution in wind resource assessments leads to higher estimates of wind potential. Comprehensive wind resource data on a global scale was not available for this study, however.

Bioenergy

Bioenergy for electricity and heat

Technology overview

Several feedstock and conversion technology combinations are available to produce electricity, heat or both via combined heat and power (CHP) systems (IEA Bioenergy, 2009).

The co-firing of solid biomass materials with coal in existing large power station boilers has proved to be one of the most cost-effective and efficient large-scale means of converting biomass to electricity and, where relevant, district heating. This approach makes use of the existing infrastructure of the coal plant and thus requires only relatively minor investment in biomass pre-treatment and fuel feeding systems. The method also profits from the comparatively higher conversion efficiencies of these coal plants. The proportion of biomass that can be co-fired directly by simply mixing biomass and coal and injecting them together into the boiler is, however, limited to approximately 10% of coal replacement. For larger percentages, modifications or replacements of coal mills and burners are typically required. The alternative options of indirect co-firing using a pre-gasifier and parallel co-firing (using a completely separate combustion installation that feeds steam to the existing power plant) are designed to avoid these issues, but are more capital intensive than direct co-firing. Pelletised fuels are commonly used to minimise transport costs and ease handling issues. Such fuels are transported by ship economically over large distances (*e.g.* from British Columbia to Europe). Recently, further refining and pre-treating of biomass (for example, through torrefaction processes) have been used to produce fuels that are more “coal like” in their physical and combustion properties and that can be used in higher proportions within plants designed for coal firing (see *e.g.* IEABCC, 2011a).

In biomass-based power plants, the heat produced by direct biomass combustion in a boiler can be used to generate electricity via a steam turbine. This technology is currently the cheapest and most reliable route to produce power from biomass in stand-alone applications. The efficiency of power generation depends on the scale of the plant. At a scale compatible with the availability of local biomass feedstocks, power generation efficiencies using steam turbines tend to be much lower than those of conventional fossil-fuelled plants. Technologies that aim to improve efficiencies at a lower scale (such as Stirling engines and Organic Rankine Cycle systems) have been demonstrated, but are not yet widely deployed.

In waste-to-energy plants, municipal solid waste (MSW) is converted to electricity and/or heat. MSW is a highly heterogeneous and usually heavily contaminated feedstock, which calls for robust technologies and rigorous controls over emissions, leading to relatively high costs. Different technologies are available, and the choice usually depends on the degree of separation of the different MSW fractions. The high capital and operating costs of such a plant mean that, to produce electricity competitively, the plant needs to charge the waste supplier a disposal fee. This arrangement is possible in areas where alternative disposal routes are expensive or unavailable, but not where alternative disposal is available at low cost.

Gasification is a thermochemical process in which biomass is transformed into fuel gas, a mixture of several combustible gases. Gasification is a highly versatile process, because virtually any biomass feedstock can be converted to fuel gas with high efficiency. The fuel gas can, in principle, be used directly to produce electricity via engines or gas turbines or at higher efficiency than via a steam cycle, particularly in small-scale plants (<5-10 MW_e). At larger scales (>30 MW_e), gasification-based systems can be coupled with combined gas and steam turbines, again providing efficiency advantages compared to combustion. The efficiency and reliability of such plants still need to be fully established. Although several projects based on advanced concepts, such as biomass integrated gasification combined cycle (BIG/CC), are in the pipeline in northern Europe, United States, Japan, and India, the future is not yet clear for large-scale biomass gasification for power generation.

Anaerobic digestion is the biological degradation of biomass in oxygen-free conditions to produce biogas, a methane-rich gas. Biogas can be burned in power generation devices for on-site cogeneration. It can also be upgraded to natural gas standards for injection into the natural gas network as biomethane, for use directly as gaseous biofuel in gas engines for power generation, or as a fuel for vehicles (particularly "captive" fleets such as buses or commercial vehicles). Anaerobic digestion is particularly suited to wet feedstocks, such as animal manure, sewage sludge from waste water treatment plants, wet agricultural residues and the organic fraction of MSW. Anaerobic digestion also occurs naturally underground in landfills and produces landfill gases that can be collected for use in energy applications. Anaerobic digestion is a well-established commercial technology, although its economic case relies heavily on the availability of very cheap or free feedstock such as sewage sludge, manure and some agricultural residues. Sewage sludge digestion and use of landfill gas are globally the most common forms of anaerobic-digestion-generating energy at present, because they are compatible with pollution control, and this underwrites some of the technology costs.

Combined heat and power (CHP) plants, which allow an economic use of the waste heat produced in biomass power generation, are an effective way to significantly increase the overall efficiency of a power plant (and hence its competitiveness) from either co-firing or stand-alone biomass plants. When a good match exists between heat production and demand, such cogeneration plants have typical overall (thermal plus electric) efficiencies in the range of 80%-90%. For domestic and commercial heating applications, however, the scale of biomass CHP plants is often limited by the total local heat demand and by its seasonal variation, which can significantly affect economic returns.

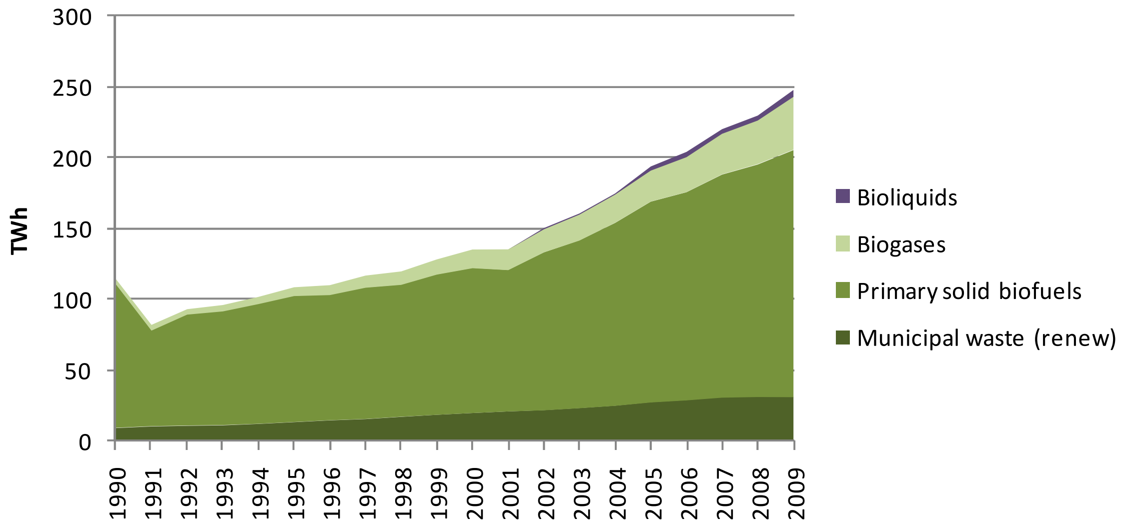
In addition, heat can be produced from biomass in efficient stoves or boiler installations in stand-alone applications. Commercially available systems range from very large boilers used in the paper and timber sectors to small installations that provide heat for individual houses from logs, wood chips or wood pellets. Heat can also be provided from the gas produced by the anaerobic digestion of, usually, wet biomass, and from the gas produced by thermal gasification of biomass. Small-scale thermal gasification systems for heating purposes are entering the market in China, India and South-East Asia, although they have not yet demonstrated reliable operation (IEA Bioenergy, 2009).

An alternative to providing heat directly is to produce a biomass-derived gas, which after refinement can be fed into the gas network and substituted for natural gas and to provide heat (or used for power generation). The gas can be produced by an anaerobic process, with the gas being cleaned to remove pollutants, stripped of the CO_2 content to produce methane, and then compressed and injected into a pipeline. Such systems are now established and have entered the market in Germany and a number of other EU countries. Alternatively, it should also be possible to produce gas by the thermal gasification of biomass, although such processes are only now on the point of large-scale demonstration (IEA Bioenergy, 2009).

Current market status

Electricity supply from bioenergy has been rising steadily since 1991, and in 2009, bioenergy provided some 248 TWh of electricity, equivalent to 1.24% of global production (Figure 2.1). This energy was principally derived through combustion and power generation via steam turbines. Co-firing of biomass with coal is an increasingly important route for using biomass for power production at a large scale. IEA Bioenergy Task 32's on-line database that tracks co-firing globally now has over 200 entries (IEABCC, 2011b).

Figure 2.1 Electricity generation from bioenergy, 1990-2009



Key point: Electricity supply from bioenergy is dominated by solid biomass and has been rising steadily since 1991.

Costs and cost trends

The costs of heat and/or power production from bioenergy depend not only on the technology and operational scale but also on the quality, type, availability and cost of biomass feedstocks, and on the pattern of energy demand (especially whether a steady demand exists for heat), meaning that cost estimates inevitably span a wide range. The investment costs for a biomass plant with a capacity of 25-100 MW_e are between USD 2 600/kW and USD 4 100/kW. With a fuel cost of USD 1.25/GJ to USD 5/GJ, the electricity cost would be between USD 0.069/kWh and USD 0.15/kWh at a 7% discount rate (IPCC, 2011). The capital cost of co-firing is much lower (USD 430/kW to USD 900/kW, depending on configuration), and at the same fuel costs, co-firing provides electricity at USD 0.022/kWh to USD 0.067/kWh (IPCC, 2011).

Many key components of bioenergy systems (such as boilers) are very well established, and the scope for cost reduction may be limited. However, considerable scope for overall project cost reduction may still be available through cost-effective design and plant standardisation, where this is possible.

The technologies for producing heat from the various biomass sources are well established and can provide heat cost effectively in favourable circumstances. Critical factors influencing the competitiveness of bioenergy heating systems include the scale, constancy of the heat load, and the availability and cost of the fuels. System and fuel costs also vary significantly between markets. The scale of heating plants, for example, can vary between 5 kW and many megawatts. At a small scale, investment costs vary between USD 310/kW$_{th}$ and USD 1 200/kW$_{th}$ (IPCC, 2011).

Significant cost reduction potential is limited, although costs can be expected to fall in particular markets as capacity grows, stimulating larger-scale and more competitive supply chain opportunities, for equipment and more efficient fuel supply chains. The Carbon Trust in the United Kingdom has estimated that, during the market development phase, capital cost reductions of about 25% should be possible (Carbon Trust, 2007).

Current policy environment

Bioenergy for electricity and heat production is a major component of many plans for expanding the use of renewable energy. In the Renewable Energy Action Plans drawn up by each EU country to show how the country will fulfil its commitments under the EU Renewable Energy Directive by 2020, 19% of the renewable electricity and 77% of the renewable heat will come from bioenergy (ECN, 2011).

Some bioenergy applications are already cost-effective, particularly where fuel supply is secure. Examples include using a residue or waste produced within industries such as those producing timber and paper, and within the sugar industry, where bagasse is used as a fuel for power generation, and with surplus power exported for other users. In other cases, the technologies are an integral part of waste management systems, and the costs are, in part, offset by avoided waste disposal costs (*e.g.* landfill gas and sewage gas). Bioenergy power generation is also frequently included for support within renewable energy support schemes such as feed-in tariffs, certificate schemes, quota obligations or tenders.

In common with the other renewable heat technologies, support for biomass heating applications has received less attention than the electricity and transport fuel sectors. Policy design for renewable heat is different from renewable electricity due to a number of key differences between the delivery of heat and electricity (Connor *et al.,* 2009). To date, the most widely adopted financial mechanisms in the European Union for the support of renewable heat technologies, including biomass, are direct capital grants for the purchase of a heating system. Recently, a number of countries have been introducing more innovative renewable heat policies, designed as government budget-neutral policies, or allocating and distributing the additional costs of renewable heating technology according to the "polluter-pays" principle.

A number of countries have deviated from financial incentive schemes to introduce use obligations for a specific renewable heat technology or for renewable heat in general. Another regulatory approach consists of requiring a defined share of a building's heat demand to be supplied by renewable energy, such as in the London "Merton Rule" and the German 2009 building regulations. This type of obligation allows for competition between renewable (heating) technologies, but lacks any incentive to exceed the required renewable share in heating demand, which, in the case of the Merton Rule, is a modest 10% share. When applied to new buildings only, the effect, in many cases, is limited, because annual construction rates in OECD countries are, on average, about 1% of the total building stock. In both examples, the regulation applies at the individual building level, discouraging more ambitious approaches. In a further recent development, the government of the United Kingdom announced the details of the Renewable Heat Incentive policy, the first example of a feed-in tariff policy for the heat market (DECC, 2010).

Other major issues for bioenergy projects relate to the development of appropriate supply chains of the fuel material, because such projects require a regular supply of material that meets specific quality requirements and is available at an affordable price. For smaller projects, resources can be available from local supply chains, and their establishment can have important economic benefits, creating local jobs or supporting existing forestry or other rural industries by providing additional streams of revenue. For larger-scale operations, such as co-firing applications, fuels are likely to be supplied internationally. With such projects, similar concerns may arise about the sustainability of the fuel supply and the likely environmental, economic and social impacts where the fuels are sourced. Similar steps to those being developed for transport biofuels need to be taken; for example, the Global Bioenergy Partnership[3] is developing sustainability criteria that apply equally to the heat and electricity and the transport fuel sectors.

IEA projections and mid-term potential

The long-term potential for bioenergy will be determined by the likely availability and costs of the fuel feedstocks. Thus the potential is inevitably uncertain because of the many factors influencing the availability of suitable wastes, residues and other potential fuels including energy crops. The study of the potential for bioenergy carried out for this publication (IEE, 2010) estimates the bioenergy potential for heat and power in all focus countries at 99 EJ (see Annex for a country list). Moderate bioenergy scenarios suggest that, by 2050, the annual sustainable bioenergy potential could be between 200 EJ and 500 EJ (IEA, 2011b). Residues from forestry and agriculture and other organic wastes could provide between 50 EJ/y and 150 EJ/y, with the remainder coming from surplus forestry growth or from energy crops.

In the IEA 2010 *World Energy Outlook* (*WEO*) (IEA, 2010a) bioenergy and waste[4] contribute 1 379 TWh of electricity globally (4.6%) in power generation by 2030 in the 450 ppm Scenario. The projection for heat stands at 1 225 Mtoe in the same year. Assessments of the usage of bioenergy for heat, however, must distinguish between very inefficient traditional use of biomass and modern use. Projections of modern biomass usage are available in the *WEO* New Policies Scenario. Here modern biomass demand for heating is expected to increase from 297 Mtoe in 2008 to 554 Mtoe in 2035.

Analysis and prospects

Electricity can be produced from biomass on demand, as long as the fuel supply is reliable and consistent, which enables the power produced to be predictable and dispatchable. Co-firing provides a way of directly displacing coal from the generation mix, and thereby reducing emissions from high-carbon sources and making some impact within a sector where emissions are generally considered to be "locked in". Extending the use of this technology to highly coal-based economies (such as those in China and India) could help to reduce emissions in the short term, and with limited need for capital investment.

Optimising the efficiency of use of the bioenergy resource involves operating power generation systems in the CHP mode. Cost-effective operation in this way, however, requires a stable and consistent heat demand, which is best provided by industrial heat loads (such as in paper or sugar production) or via access to a heat distribution network.

Biomass materials as fuel can address concerns about climate change, reduce environmental impacts of using fossil fuels, and potentially improve energy security. In addition, biomass materials can improve resource utilisation or reduce waste generation, thereby adding to the productivity and profitability of industries that provide the raw materials (such as agriculture,

[3] See www.globalbioenergy.org for details.

[4] Including non-renewable waste.

forestry and waste management) and leading to additional employment opportunities in producing, harvesting and delivering the fuels, particularly within rural areas.

Establishing a reliable fuel supply chain is an essential component of any successful bioenergy project and is one of the major risk factors when financing such schemes. In the long term, ensuring that a supply infrastructure is available to deliver sustainable fuels will be an essential prerequisite to meeting scenario projections.

Biofuels

Technology overview

Today's biofuels are principally produced by well-developed, commercial processes (IEA, 2011b). These fuels include sugar- and starch-based ethanol, oil-crop-based biodiesel, and biogas derived from anaerobic digestion processes. Typical feedstocks used in these processes include sugarcane; sugar beets; starch-bearing grains such as corn and wheat; oil crops such as rape (canola), soybean and oil palm; and in some cases animal fats and used cooking oils.

The produced fuels can then be blended with gasoline or diesel fuels and used in conventional vehicles (typically in blends of 5%–15%). Ethanol can also be used alone or in much higher blends in modified or "flex-fuel" vehicles. Methane gas produced from biomass via anaerobic digestion can be used as a vehicle fuel, possibly blended with methane from fossil fuel sources.

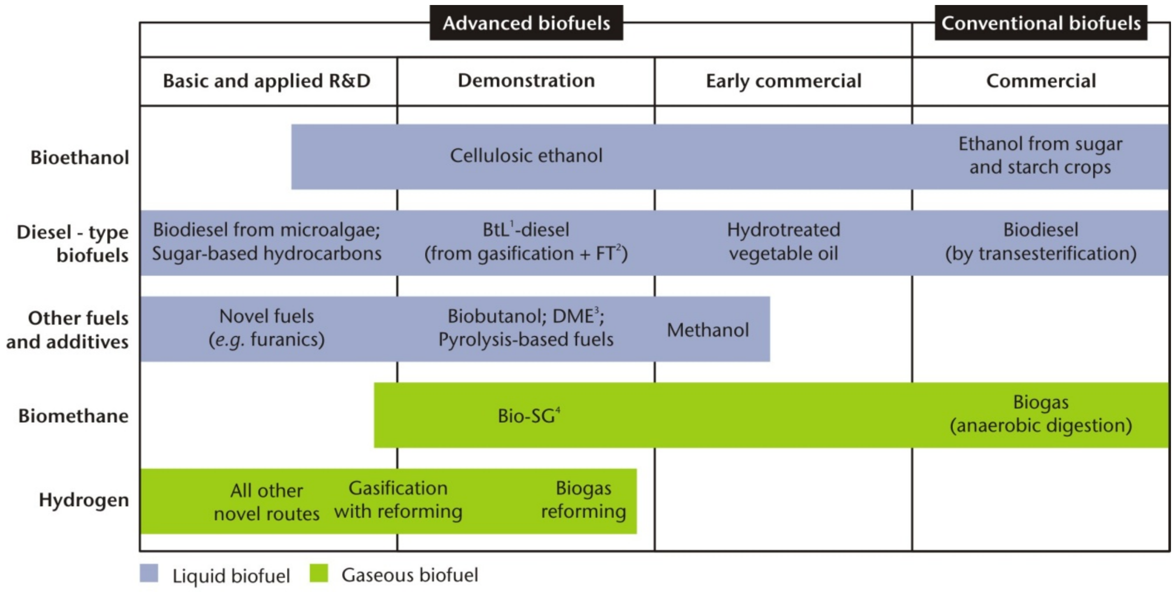
These routes to biofuels could be readily deployed, because they are based on well-established and proven technologies and on crops that are widely produced. However, a number of drawbacks are also associated with these fuels, including:

- the overall sustainability of the production and use of these fuels (taking into account concerns about competition for the feedstocks between food and fuel), and the overall greenhouse gas balance for the production and use of the fuels (considering the emissions associated with direct and indirect land-use change);
- some limitations on the extent to which the fuels produced can be used by the current vehicle fleet (the so-called blending wall), which can restrict the level of biofuels that can be achieved. Such restrictions can be addressed by stimulating changes in the vehicle fleet (for example, by encouraging the use of "flex-fuel" vehicles that can operate on a wide range of blends of ethanol and gasoline;
- the need for infrastructure for transporting and blending the fuels, which may not be compatible with the existing infrastructure developed for fossil fuels;
- the variability of biodiesel, depending on the feedstock from which the fuel is produced;
- the sensitivity of biofuel production costs to feedstock prices.

These concerns have also led to efforts to develop and deploy a new suite of technologies that can use feedstocks without competing for materials that can also be used as fuel and food, and/or that produce fuels that can replace or be blended with fossil fuels such as gasoline, diesel and kerosene. *The IEA Technology Roadmap Biofuels for Transport* (IEA, 2011b) envisages a major shift to these advanced processes over time, and that the role of all but the best-performing conventional biofuels will be reduced.

A wide range of advanced technologies is available for producing biofuels (Figure 2.2). But even the most mature of these technologies are just reaching the stage where the first commercial plants are being brought into production. The technologies, therefore, are not yet generally ready for widespread deployment. These advanced processes include technologies for producing fuels from cellulosic materials, either through biochemical routes (such as fermentation to sugars and thence to alcohols) or using thermochemical processes (for example, gasification to form a syn-gas, followed by Fischer Tropsch hydrocarbon production).

Figure 2.2 Technologies for producing advanced biofuels



1. Biomass-to-liquids, 2. Fischer Tropsch, 3. Dimethylether, 4. Bio-synthetic gas

Source: IEA Bioenergy (2009).

Key point: Coventional biofuels are commercial technologies, advanced biofuels at earlier development stages.

These technologies may offer advantages over the conventional biofuels processes used commercially today, such as:

- use of non-food raw materials or feedstocks that have lower land requirements;
- more efficient conversion processes;
- production of “fungible fuels” that can be blended in any proportion with fossil-based fuels;
- better overall greenhouse gas balances.

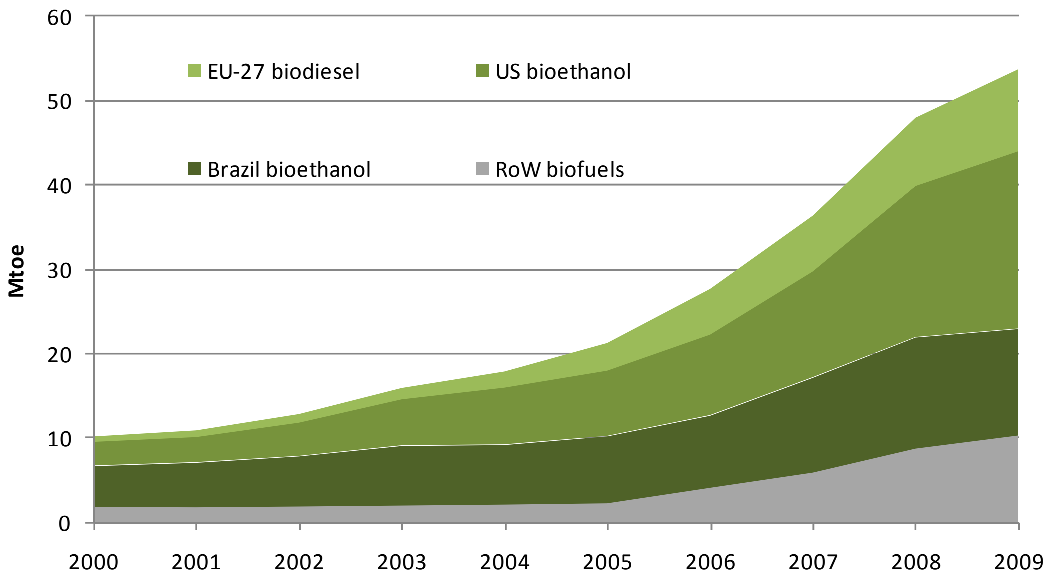
The best-developed of these technologies are at the point where the first commercial-scale plants are coming into production, others are at the pre-commercial demonstration stage, and others are still at earlier stages in the development life cycle. To date, only a few large-scale facilities employing these technologies are in operation; thus current production levels of these fuels are low.

Current market status

The production and use of biofuels have been growing rapidly, and in 2009 they provided 53.7 Mtoe, equivalent to some 3% of road transport fuels (or 2% of all transport fuels).

Production is currently dominated by the production of ethanol in Brazil (where an ethanol for fuel programme was initiated in the 1970s) and in the United States (Figure 2.3). In the European Union, the emphasis has been on biodiesel production.

Figure 2.3 Development of biofuels markets, 2000-09



Note: RoW stands for rest of world.

Key point: Global biofuels production is concentrated in Brazil, the United States and the European Union.

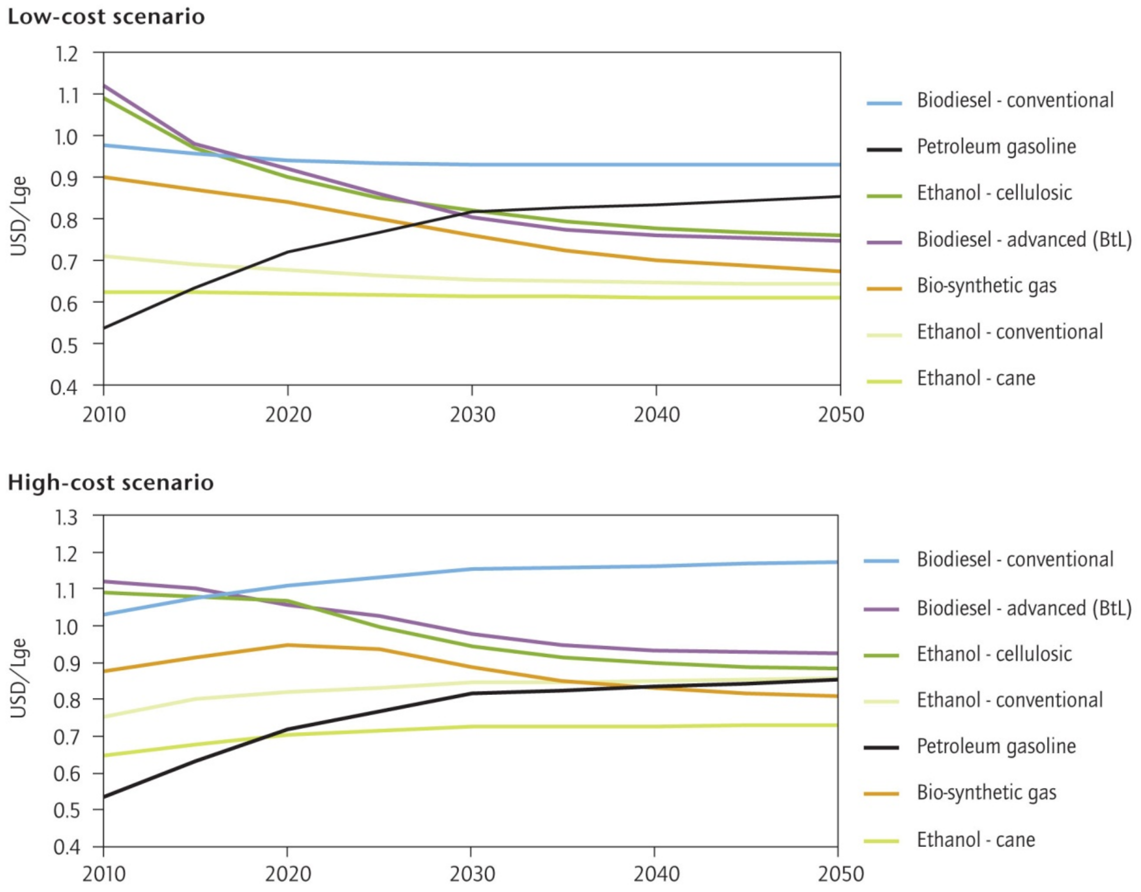
Costs and cost trends

The costs of producing conventional biofuels are largely based on the costs of the feedstock, which typically make up between 45% and 70% of overall production costs. The costs are also affected by the income that can be derived from co-products such as Dried Distillers Grains with Solubles (DDGS) or glycerines, or from other energy products such as the electricity that can be produced from residues such as bagasse and lignin, or from excess heat generated. Although these technologies are mature, continuing opportunities are available for cost reductions and improvements in process efficiency (for example, by using more effective amylase enzymes, decreasing ethanol concentration costs, or enhanced use of by-products).

Bioethanol and biodiesel are currently not cost competitive with gasoline or diesel prices, except in some markets (notably Brazil) where production costs are low. Production costs, compared to gasoline, may vary in the future, as indicated in the IEA BLUE Map Scenario (IEA, 2010b; Figure 2.4).

The capital costs of advanced biofuels production systems are generally higher than those for conventional biofuels and make up a higher proportion of the total production costs (typically 35% to 50%). Feedstock costs are less significant and should in many cases be much less susceptible to feedstock cost variability and the price for processes that rely on residues or non-food crops. Because these processes are not yet fully commercialised, production cost estimates are uncertain and based on design studies rather than practical experience. However, estimates of costs are available for a number of advanced processes (Figure 2.4). Also, because the processes are novel, considerable scope is available for cost reduction and improvements in efficiency and product yield. These processes are expected to yield biofuels that are competitive with gasoline (and with conventional biofuels) between 2030 and 2040 (IEA, 2011b).

Figure 2.4 Projected costs of biofuels compared to petroleum gasoline, 2010-50



Note: Lge stands for litres of gasoline equivalent.

Key message: Advanced biofuels are expected to be competitive with gasoline between 2030 and 2040.

Current policy environment

Because conventional biofuels are not currently cost competitive with gasoline or diesel prices (with some exceptions such as bioethanol in Brazil), the market for biofuels is policy driven. The motivations within the policies may be to improve energy diversity and security, to reduce greenhouse gas emissions, or to provide support to the rural and agricultural sector, with different emphasis given to each motivation in each market (IEA, 2011a).

The principal policy tools that have been used to stimulate demand for biofuels are blending mandates, coupled with fuel duty rebates. Mandates are now in place in nearly 50 countries (IEA, 2011b). Such measures have successfully stimulated demand wherever they have been employed, as long as they are backed up legally with sanctions for non-compliance. Merely setting aspirational targets without sanctions is ineffective.

Policy making has been complicated by concerns about the sustainability of some conventional biofuels options, as discussed above. Thinking and analysis on these complex issues, and particularly on emissions associated with direct and indirect land-use change, have been evolving rapidly over the past five years.

Against this shifting background, policy makers face a difficult task. They need to incentivise the production and consumption of "sustainable biofuels" so as to meet their policy priorities. At the same time, the policy package needs to encourage the development and commercialisation of promising advanced technologies while providing a stable policy framework that enables industry to invest with confidence.

The pace of development and the market introduction of the new technologies have also been slower than anticipated. Adjustment of some policies and targets and a flexible approach have been necessary.

A number of biofuels polices include specific measures to encourage better-performing biofuels, including those classified here as advanced biofuels. US and EU policies are designed to encourage better-performing biofuels to improve the overall sustainability of biofuels, particularly with respect to the greenhouse gas balance. In the United States, for example, an obligation creates a market for ethanol from cellulosic feedstocks, along with a broader mandate reserved for advanced biofuels. In the European Union, the requirements on the greenhouse gas balance are tightening, and biofuels judged to be from advanced processes count twice toward the Renewable Energy Directive targets and associated National Renewable Energy Action Plans. The biofuels policy in Japan is also directed at encouraging these advanced processes.

IEA projections and mid-term potential

The study of the potential for biofuels carried out for this paper (IEE, 2010) estimates the 2030 feedstock potential for biofuels at 33.24 EJ (feedstock potential). In the IEA 2010 *World Energy Outlook,* biofuels contribute 283 Mtoe (11.8 EJ) in 2030, corresponding to 10.2% of global transport energy demand in the 450 Scenario (IEA, 2010a).

Analysis and prospects

In the short term, conventional bioenergy use is expected to continue to grow as the increasing number of mandates is fulfilled by conventional biofuels.

The future expansion will be constrained, in some cases, by prospective regulations, which are setting tighter thresholds for greenhouse gas balances and are aiming to stimulate deployment of the new technologies, as discussed above.

In the longer term, the IEA Roadmap on Biofuels for Transport (IEA, 2011b) envisages continuation for the best-performing conventional biofuels systems, based on very land-efficient crops, residues and feedstocks that are well integrated with food production. In the longer term, however, much of the conventional biofuels production will face more competition for feedstock in the face of rising food demands, and more competition from advanced technologies based on wastes and residues and better-performing crops using less prime land.

The advanced processes are still at the development, demonstration and early deployment stages. Their deployment will rely on continued efforts in R&D by private and public sectors, and critically on the deployment of the first full-scale commercial facilities. This is the major challenge in this sector, because technical, commercial and political risks are associated with their introduction. In particular, the production costs from the early plants will be higher than the anticipated future costs, and in some cases also higher than those of biofuels produced by conventional processes. As a result, the market introduction may need to rely on differential support for the products and be backed up by specific mandates that encourage the introduction of these processes and fuels. Also, the scale of the likely investments makes it difficult for governments to provide support for early-stage plants by the usual mechanisms such as capital grants, even for countries such as the United States or the European Union. Government support, involving grants and loan guarantees, and some novel mechanisms, involving public-private partnerships, are likely to be needed to bring these technologies to full-scale operation.

The Roadmap analysis also indicates that biofuels will play a particularly important role in the heavy and long-distance transport sectors (such as long-haul goods transport, and air and sea travel) rather than in the light-vehicle sector, where electric vehicles and other low-carbon options will play a particularly important role in the future. Currently produced conventional biofuels are not well suited to these sectors.

Because of these factors, the Roadmap shows the gradual phasing-out of conventional biofuels based on vegetable oils and corn by about 2040, but a continuing role for fuels derived from cane sugar, given the high productivity and lower costs associated with this feedstock.

Geothermal energy

Technology overview

Geothermal technologies use energy stored in rock and in trapped vapours or liquids such as water or brines. These resources can be used for generating electricity and to provide heat. Power generation typically relies on geothermal resource temperatures of over 100°C. Geothermal resources spanning a wider range of temperatures can be used in applications such as space and district heating, and other low-temperature applications. Geothermal heat can also be used to generate cooling using adsorption chillers (IEA, 2011c).

Geothermal technologies differ in the type of resource that they use for power or heat generation. The three types of resources are: high-temperature hydrothermal resources (volcanic resources), low and medium-temperature hydrothermal resources, and hot rock. The first two resources are available in selected areas; the hot rock resource is available in all places, not just in geothermally active ones.

Geothermal technology using naturally heated steam or hot water from high-temperature hydrothermal reservoirs (the first type of resource) is well established and fully commercial. Many existing geothermal power plants use steam produced by "flashing" (*i.e.* reducing the pressure of) the geothermal fluid produced from the reservoir. Geothermal power plants today can use water in the vapour phase, a combination of vapour and liquid phases, or liquid phase only.

The choice of plant depends on the depth of the reservoir, and the temperature, pressure and nature of the entire geothermal resource. The three main types of plant are flash steam, dry steam and binary plants. All forms of currently accepted geothermal development use re-injection as a means of sustainable resource exploitation.

Flash steam plants, which make up about two-thirds of geothermal installed capacity today, are used where water-dominated reservoirs have temperatures above 180°C. In these high-temperature reservoirs, the liquid water component boils, or "flashes," as pressure drops.

Dry steam plants, which make up about a quarter of geothermal capacity today, directly utilise dry steam that is piped from production wells to the plant and then to the turbine. Control of steam flow to meet electricity demand fluctuations is easier than in flash steam plants, where continuous up-flow in the wells is required to avoid gravity collapse of the liquid phase.

Binary plants constitute the fastest-growing group of geothermal plants, because they are able to also use the low- to medium-temperature resources, which are more prevalent. Binary plants, using an organic Rankine cycle (ORC) or a Kalina cycle, typically operate with temperatures varying from as low as 73°C (at Chena Hot Springs, Alaska) to 180°C. In these plants, heat is recovered from the geothermal fluid using heat exchangers to vaporise an organic fluid with a low boiling point (*e.g.* butane or pentane in the ORC cycle and an ammonia-water mixture in the Kalina cycle), and drive a turbine. Today, binary plants have an 11% share of the installed global generating capacity and a 44% share in terms of the number of plants (Bertani, 2010).

Geothermal energy can also provide heat. Even geothermal resources at temperatures of 20°C to 30°C (*e.g.* flood water in abandoned mines) may be useful to meet space heating demand or other low-temperature applications. Geothermal "heat-only" plants can feed a district heating system, as can the hot water remaining from electricity generation, which can also be used in applications demanding successively lower temperatures. Because transport of heat has limitations, geothermal heat can only be used where a demand exists in the vicinity of the resource, although in some cases the availability of heat can be a spur to economic development of enterprises able to make use of a low-cost heat supply.

Geothermal technologies using hot rock resources could potentially enable geothermal energy to make a much larger contribution to world energy supply. Technologies that utilize hot rock resources are also known as **enhanced or engineered geothermal systems (EGS).** These systems aim at using the earth's heat where no or insufficient steam/hot water is available or where permeability is low. EGS plants differ from conventional plants only as far as heat/steam extraction is concerned. EGS technology, therefore, is centred on engineering and creating large heat exchange areas in hot rock. The process involves enhancing permeability by opening pre-existing fractures and/or creating new fractures.

EGS has been under development since the first experiments in the 1970s on very-low-permeability rocks, and is also known as hot dry rock technology. On the surface, the heat-transfer medium (usually hot water) is used in a binary or flash plant. Among current EGS projects worldwide, the European scientific pilot site at Soultz-sous-Forêts, France, is in the most advanced stage and has recently commissioned the first power plant (1.5 MW_e), thereby providing an valuable database of information. In 2011, 20 EGS projects are under development or under discussion in several EU countries. EGS research, testing and demonstration are also under way in the United States and Australia. The United States has included large EGS RD&D components in its recent clean energy initiatives as part of a revived national geothermal programme. The IEA projects EGS to become commercially viable in 2030 and to account for the majority of geothermal deployment until the year 2050 (IEA, 2011c).

Because this analysis is focusing on technologies entering or in the commercial deployment phase, the rest of this section concentrates on conventional geothermal for electricity and heat production, which is a mature technology, rather than on enhanced geothermal, where today's main interest is judged to be on R&D and on technology demonstration.

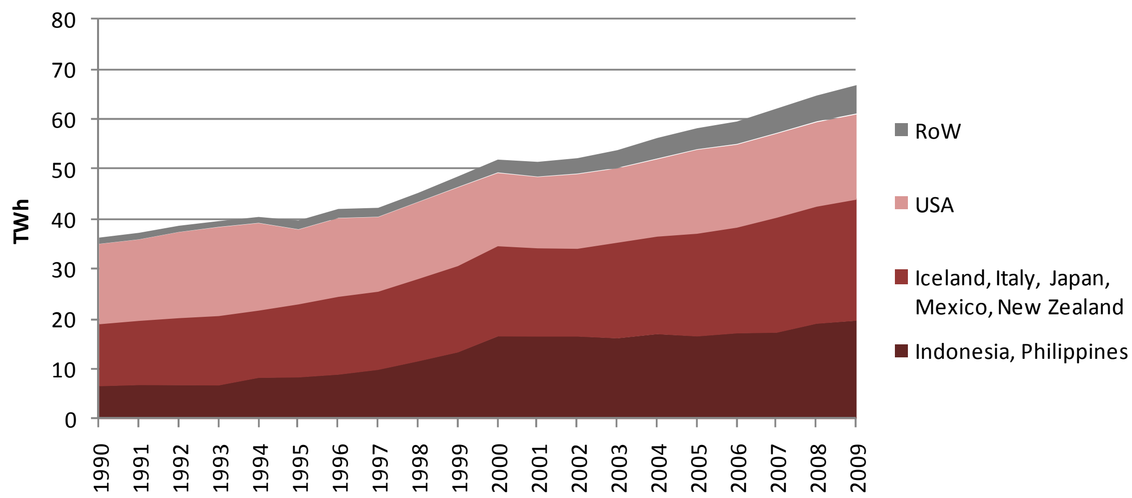
Conventional geothermal is a mature technology that can provide baseload power or year-round supply of heat. The resource can be exploited only in favourable regions (a constraint that can be relaxed when EGS systems are ready to be commercialised). Matching heat demand to resource availability can be difficult given the costs and difficulty of transporting heat long distances.

Current market status

In 2009, global geothermal power capacity was 10.7 GW_e and generated approximately 67.2 TWh_e/yr of electricity, at an average load of 6.3 GWh/MW_e (Bertani, 2010). A remarkable growth rate from 1980 to 1985 was largely driven by the temporary interest of the hydrocarbon industry, mainly Unocal (now merged with Chevron), in geothermal energy. Geothermal electricity provides a significant share of total electricity demand in Iceland (25%), El Salvador (22%), Kenya and the Philippines (17% each), and Costa Rica (13%). In absolute figures, in 2009, the United States produced the most geothermal electricity: 16 603 GWh_e/yr from an installed capacity of 3 093 MW_e (Figure 3.1).

Total installed capacity of geothermal heat (excluding heat pumps) equalled 15 347 GW_{th} in 2009, with a yearly heat production of 223 petajoules (PJ); China shows the highest use of geothermal heat (excluding heat pumps), totalling 46.3 PJ/yr geothermal heat use in 2009 (Lund, Freeston and Boyd, 2010).

Figure 3.1 Electricity generation from geothermal energy, 1990-2009



Key point: Power generation from geothermal energy is concentrated in only a few countries globally.

Costs and cost trends

Where an accessible high-temperature geothermal resource exists, generation costs can be competitive with alternatives.

Geothermal electricity development costs vary considerably, because they depend on a wide range of conditions, and whether the project is a greenfield site or expansion of an existing plant. Development costs are also strongly affected by the prices of commodities such as oil, steel and cement. In 2008, the capital costs of a greenfield geothermal electricity development ranged from USD 2 000/kW_e to USD 4 000/kW_e for flash plant developments and USD 2 400/kW_e to USD 5 900/kW_e for binary developments (IEA, 2011c).

Typical O&M costs also vary depending on the plant. They range from USD 9/MWh_e (large flash, binary in New Zealand) to USD 25/MWh_e (small binary in the United States), excluding well replacement drilling costs (IEA, 2011c). When make-up wells are considered to be part of O&M costs, which is common in the geothermal electric industry, O&M costs are estimated at USD 19/MWh_e to USD 24 /MWh_e as a worldwide average (IPCC, 2011), although they can be as low as USD 10/MWh_e to USD 14 /MWh_e in New Zealand (Barnett and Quinlivan, 2009).

On average, production costs for hydrothermal high-temperature flash plants have been calculated to range from USD 50/MWh_e to USD 80/MWh_e. Production costs of hydrothermal binary plants vary on average from USD 60/MWh_e to USD 110/MWh_e. Some binary plants have higher upper limits: levelised costs for new greenfield plants can be as high as USD 120/MWh_e in the United States and USD 200/MWh_e in Europe, for small plants and lower-temperature resources (IEA, 2011c).

Flash plants using high-temperature resources may be considered a proven technology, but costs can be expected to continue to fall, with an average learning rate of 5%.[5] Binary (hydrothermal) plants, using lower-temperature resources, are also considered to be a relatively mature technology. For binary plants, which currently have small capacities, costs will decrease to

[5] A learning rate of 5% means that, with each doubling of installed capacity, costs are 5% lower.

competitive levels as capacities increase. Hydrothermal flash plants are expected to be fully competitive between 2020 and 2025. Hydrothermal binary plants should be fully competitive after 2030 (IEA, 2011c).

Current policy environment

Some geothermal power plants have already proven to be competitive with newly built conventional power plants, where hydrothermal resources offer sufficiently high temperatures or where electricity prices are high and geothermal plants can provide baseload electricity competitively. In some other markets, where only low- and medium-temperature hydrothermal resources are available, geothermal technologies may not yet be commercially viable. To stimulate investment in the capital-intensive projects and provide sufficient investor confidence, economic incentive schemes are differentiated along levels of competitiveness per technology and per location. These schemes include feed-in tariffs, feed-in premiums, renewable portfolio standards, fiscal incentives and investment subsidies, as well as framework conditions such as access to grids.

As is the case for the other heat-generating renewable technologies, incentives that aim to increase geothermal heat production have so far received less attention than those for renewable electricity. The cogeneration of electrical and thermal power from geothermal sources offers potential both for improved economic performance and for increased overall renewable energy usage. Recent innovative renewable heat approaches, such as the UK renewable heat feed-in tariff, deserve consideration (DECC, 2010).

Several non-economic barriers can significantly hamper the effectiveness of geothermal support policies; difficulties in obtaining permits, for example, can hinder new geothermal plants. Many countries that lack specific laws for geothermal resources currently process geothermal permits under mining laws that were conceived with objectives other than renewable energy production.

Permitting procedures can consist of numerous steps, resulting in long lead times. The lack of regulation for geothermal energy is inhibiting the effective exploitation of the resource. Measures that have been successful include: enforcing legislation that separates geothermal resources from the mining code, geothermal rights clearance as part of a long-term concession in public tendering, and introducing simplified procedures consisting of fewer steps or even a "one-stop shop" approach.

The main risks for geothermal projects are associated with finding and proving a resource. If water flow rate and temperature are not high enough, geothermal development can fail, particularly if the necessary flow rate cannot be reached in low-temperature projects. Given the high uncertainty in finding a geothermal resource when drilling, debt financing usually only becomes an option when the resource has been successfully proven. Reservoir risk insurance schemes reduce the need for equity through partial coverage of costs should the project become uneconomical. Thus these schemes can be an important way of reducing geothermal development costs. Such schemes are available in several geothermal markets either from government programmes (France, Germany, Switzerland) or commercial sources (Germany and Iceland).

For deep geothermal drilling and reservoir management, skilled companies and well-trained personnel are currently concentrated in just a few countries. As geothermal developments spread, demand for trained geothermal scientists and engineers will increase, even in countries that currently have limited geothermal experience. This predicted trend means that geothermal science and engineering programmes will need to be improved and expanded. Information exchange platforms within regions with geothermal resources should be enhanced to increase awareness of geothermal technology.

IEA projections and mid-term potential

Global, long-term technical potential for geothermal electricity has been estimated at 45 EJ/yr, *i.e.* 12 500 TWh_e (Krewitt *et al.*, 2009). The same study estimates resources suitable for direct use at 1 040 EJ/yr, *i.e.* 289 000 TWh_t. These estimates of technical potential exclude advanced geothermal technologies that could exploit hot rocks or offshore hydrothermal, magma and geopressured resources, which, in principle, could be much larger. Although geothermal energy has great technical potential, its exploitation is hampered by costs and distances of resource from energy-demand centres.

The study carried out for this publication estimates the 2030 potential at 760 TWh of electricity in all 56 focus countries. Note that this does not take into account the contribution of enhanced geothermal systems. The potential for heat generation is estimated at 340 TWh (1.2 EJ). The potential for heat production is limited due to the need to closely match resource and demand. Note that the potential is significantly higher when taking into account enhanced geothermal systems.

The *ETP 2010* BLUE Map Hi-REN scenario (IEA, 2010b) foresees geothermal electricity producing 1 400 TWh annually by 2050 (about 3.5% of global electricity production by that time). Conventional high-temperature resources, as well as deep aquifers with low and medium-temperature resources, are expected to play an important role in geothermal development. Advanced hot rock geothermal technologies are assumed to become commercially viable soon after 2030. The IEA *Technology Roadmap: Geothermal Heat and Power* (IEA, 2011c) foresees 200 GW_e of installed capacity by 2050, including 100 GW_e hydrothermal electricity capacity and 100 GW_e from EGS. The Roadmap also foresees direct heat production equivalent to 5.8 EJ (about 1 600 TWh thermal energy) by 2050.

Analysis and prospects

Conventional high-temperature hydrothermal geothermal is a mature and commercial technology, which is already fully competitive for producing baseload electricity and heat in markets where resource conditions are appropriate. Technologies are also extending the application to low- and medium-temperature hydrothermal resources (aquifers) at costs that are expected to become competitive in an extended range of circumstances by about 2030. In the longer term, EGS systems will allow access to a much larger resource and open geothermal opportunities to more regions and countries.

The geothermal potential was once considered to be determined only by high-temperature hydrothermal resources along tectonic plate boundaries, but low- and medium-temperature resources have also proven to be of value in geothermal heat applications or binary (combined heat and power) plants. More governments could, therefore, reconsider the geothermal potential of their countries on the basis of a broader perspective that takes into account high-grade and low-grade hydrothermal resources. They could also include geothermal in their future plans, with medium-term exploitation targets.

The main barriers to extending the geothermal contribution are associated with the complexity of regulations, which have not been developed with energy production in mind and need to be made as simple and supportive as possible. From a project developer's perspective, the main issue in these markets is the risk associated with finding and proving good resources, and this can be a barrier to securing the necessary investment funds. As geothermal technology is more widely exploited, the availability of skilled personnel can also be a problem. In newer geothermal markets, or in case of binary plant development for low- and medium-temperature resources, some fiscal support may be necessary to stimulate investment.

Hydro energy

Technology overview

Hydroelectric power is derived from the energy in flowing water, from rivers or from man-made installations where water flows from a reservoir. Turbines placed in the water flow extract its kinetic energy and convert it to mechanical energy. The amount of power generated depends on the water flow and the vertical distance (the "head") that the water falls (IEA, 2010c).

Hydro power is a fully commercial and well-established mature technology, although scope exists for improving efficiency and costs and, in particular, for developing more cost-efficient technologies for small-capacity and low-head applications. Hydro power can provide a very flexible source of renewable energy, capable of delivering baseload power, meeting peak demand, or being used as a storage system. Hydro's quick-start capability helps to cope with fluctuations in supply or demand. Production can be put at risk, however, when drought limits the supply of water within a catchment area, and annual hydro production in many markets varies seasonally and from year to year, depending on rainfall levels.

The three main types of hydro schemes are storage, run-of-river and pumped storage. In **storage** schemes, a dam impounds water in a reservoir that feeds the turbine and generator. **Run-of-river** schemes use the natural flow of a river and may employ a weir to enhance flow continuity. Either of these types can involve diversion, where water is channeled from a lake, river or reservoir to a remote powerhouse containing the turbine and generator. **Pumped storage** schemes involve two reservoirs. At times of low demand and usually low electricity prices (often at night), electricity is used to pump water from the lower to an upper basin. The water is released to create power when demand and prices are high, thereby improving storage capacity and providing grid flexibility. These capabilities are particularly useful for allowing large penetration of wind and other variable power sources (IEA, 2010c, 2011d).

Hydro power projects can have significant environmental and social impacts, and analysing the balance between the benefits and effects can be a difficult task. All environmental and social impacts need to be identified and considered during the planning process so that appropriate steps can be taken to avoid, mitigate or compensate for the impacts. Much work has gone into the development of guidelines and protocols for the design of sustainable hydro projects,[6] which recognize that countries must follow an integrated approach to managing their water resources, planning developments in cooperation with other water-using sectors and taking environmental and social factors properly into account.

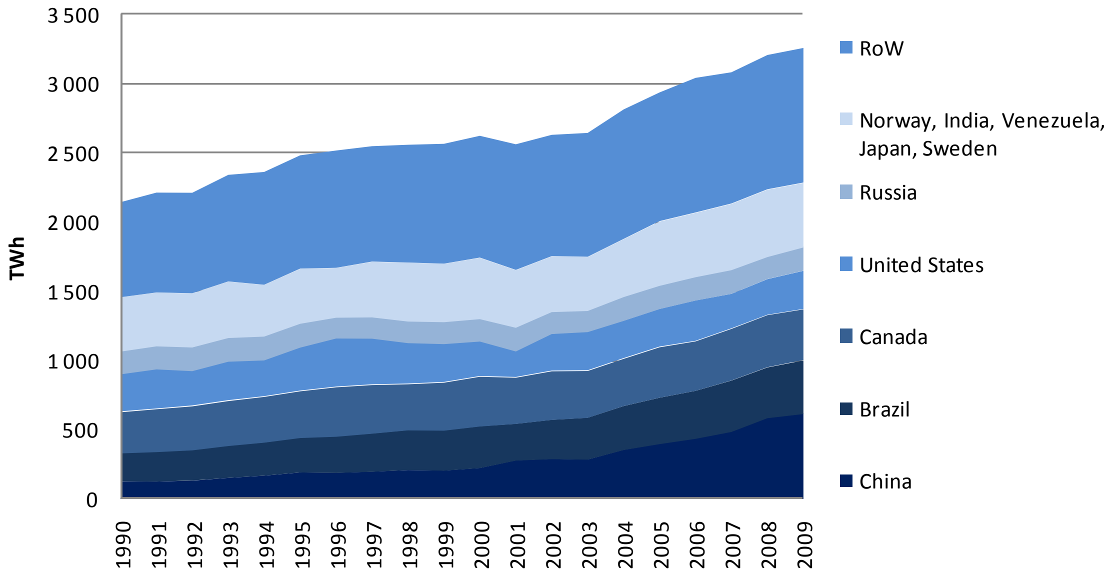
Current market status

Hydro power is the dominant source of renewable energy worldwide, producing 3 252 TWh, which is equivalent to 16.2% of global electricity production in 2009. The world leaders in producing hydro power are China, Brazil, Canada, the United States and Russia. For Brazil and Canada, hydro represents the largest share of each country's power generation, roughly 80% and 60%, respectively, depending on weather conditions in a given year. Many developed countries have also successfully tapped into their hydro potential, especially for large hydro installations, and they continue to develop their small hydro potential. Global hydro power has grown by 50%

[6] See the website of the IEA Hydropower Implementing agreement (www.ieahydro.org) for details.

since 1990, with the highest absolute growth in China (Figure 4.1). New hydro power projects are mostly concentrated in developing and emerging countries.

Figure 4.1 Developments in hydro power generation, 1990-2009



Key message: Hydropower has seen a large absolute increase, with growth particularly in China.

In the next decade, hydro power will increase by approximately 180 GW of installed capacity if projects currently under construction proceed as planned. This increase corresponds to roughly one-quarter of currently installed capacity. One-third of this increase will come from China alone. In the OECD, Turkey will see the largest capacity additions. Brazil and India also have a large capacity under construction (Figure 4.2).

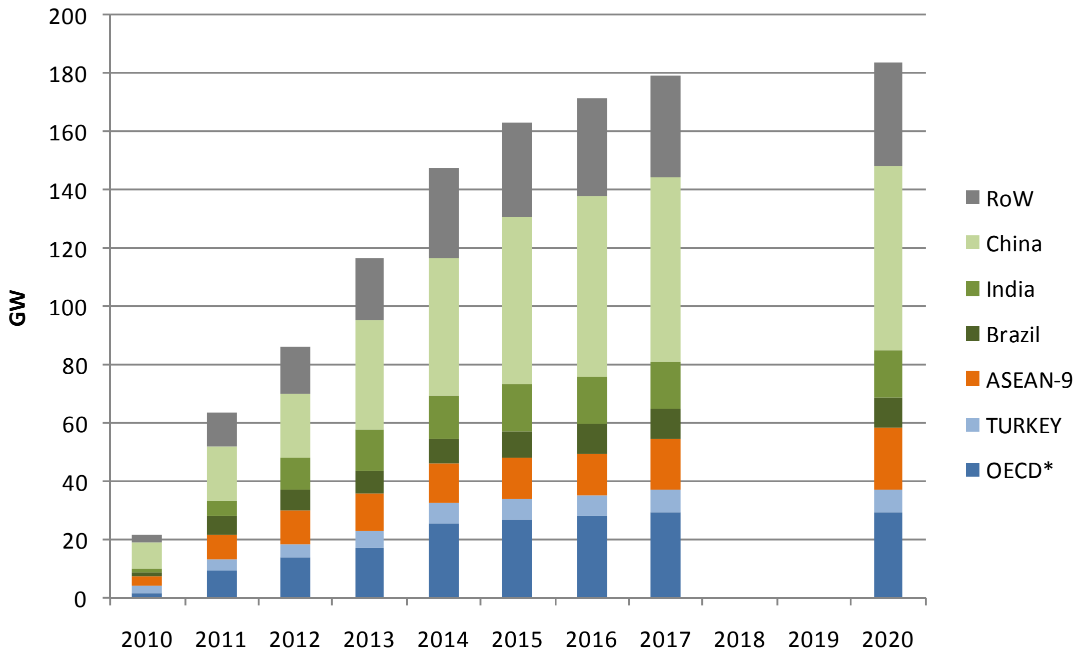
Costs and cost trends

In many cases, hydro power provides low-cost electricity competitively without financial support.

The initial investment needs for particular projects must be studied individually due to the unique nature of each hydro power project. Construction costs for new hydro power projects in OECD countries are usually less than USD 2 million/MW for large-scale hydro (> 300 MW), and USD 2 million/MW to USD 4 million/MW for small- and medium-scale hydro (< 300 MW). Parameters affecting investment costs and the return on investment include: the project scale, which can range from over 10 000 MW to less than 0.1 MW; the project location; the presence and size of reservoir(s); the use of the power supplied for baseload or peak load or both; and possible other benefits alongside power production, such as flood control, irrigation, freshwater supply, etc. Operation and maintenance costs are estimated at USD 5/MWh to USD 20/MWh for new medium to large hydro plants and approximately twice as much for small hydro (IEA, 2010c).

The generation costs of electricity from new hydro power plants vary widely, although they are often in a range of USD 50/MWh to USD 100/MWh. Generation costs per MWh are determined by the amount of electricity produced annually. Many hydro power plants are deliberately operated for peak-load demands and backup for frequency fluctuation, which increases both the generation costs and the value of the electricity produced.

Figure 4.2 Global hydropower projects under construction, cumulative additional capacity by year of expected commissioning



Note: *OECD excluding Turkey.

Key point: 180 GW of hydro capacity is currently under construction globally, one third in China.

Because most of the generation cost is associated with the depreciation of fixed assets, the generation cost decreases if the projected plant lifetime is extended. As such, the financial regime is a key factor. Many hydro power plants built 50 to 100 years ago are fully amortised and continue to operate efficiently (IEA, 2010c).

The capacity of many existing hydro power plants could be raised by 5% to 20% through the installation of new and more efficient turbines. Such refurbishment projects may be easier to accomplish than new plants from a technical and social point of view, and would provide faster and more cost-effective additional generation than new plant construction (IEA, 2010c).

Current policy environment

In many markets, large-scale hydro power can provide electricity at costs that are fully competitive with other sources in the mix, and so, unlike other renewables, particular economic support measures are not necessary. Tendering processes are widely used to procure new capacity competitively. In other markets, support is provided, particularly for smaller-scale installations, via feed-in tariffs, premiums or green certificate schemes.

The main challenges for policy makers are associated with putting in place appropriate arrangements for planning projects, and for providing for a comprehensive assessment of the environmental and social benefits and costs so as to ensure that projects are as sustainable as possible, taking into account public opinion and particularly the interests of those most likely to be directly affected. Such measures are also essential in ensuring that projects meet the environmental and social standards that legislation, regulation and lenders in multi-lateral and commercial banks apply before being able to provide funding.

Policy makers and regulators also need to ensure that the overall market structure is such as to provide proper rewards for hydro projects. This is particularly the case when valuing the flexibility of generation that hydro can provide, perhaps to balance other variable renewable resources. Properly valuing the benefits of pumped storage in a way that encourages further investment in such projects is a particular challenge.

IEA projections and mid-term potential

The study carried out for this publication estimates the 2030 potential of hydropower at 6 960 TWh in all 56 focus countries. The globally exploitable potential for hydro power is estimated at more than 16 400 TWh/year (World Energy Council, 2007). The potential is unevenly distributed, with ten countries (China, United States, Russia, Brazil, Canada, Democratic Republic of the Congo, India, Indonesia, Peru and Tajikistan) accounting for about two-thirds of the global potential. Only about 19% of this potential has been tapped so far.

The BLUE Map scenario in the *Energy Technology Perspectives 2010* (IEA, 2010b) suggests that hydro power could provide 5 749 TWh in 2050. Under this scenario, hydro power would see its share in the global electricity production increase slightly from 16.3% in 2008 to 17.3% in 2030, but then reduce to 14.1% by 2050 as other power generation technologies grow at faster rates. Hydro will continue to be a major source of renewable electricity on a global scale, contributing to baseload and providing the flexibility needed to meet peaks in demand.

Analysis and prospects

Hydro has the potential to provide both baseload and peak power, and to provide balancing services to grids. The major potential for expansion of hydro capacity lies in emerging and developing countries. In more developed markets, the potential exists to extend generation by upgrading and refurbishment of old plants and to develop smaller-scale projects where these are cost-effective and where the environmental and social impacts can be constrained. The potential also exists to extend the role of pumped hydro as a storage option.

The main challenges associated with expanding large-scale hydro involve finding appropriate ways of balancing the environmental and social benefits and costs of projects. A number of protocols, acceptable to governments and lenders, are being developed and can now be applied to projects in developed and developing countries. Providing technical assistance and capacity-building support to the application of these protocols should now be a priority for international organizations to foster a sustainable approach to hydro in emerging and developing economies where the growth potential is highest.

The other main challenge for policy makers is to support market mechanisms that reward hydro projects adequately, and in particular provide appropriate revenues for flexible operation patterns (*i.e.* curtailment in times of a potential surplus in generation, and operation in times of high demand when shortages of capacity arise).

Ocean energy

Technology overview

Five different ocean energy technologies under development aim to extract energy from the oceans, including:

- **Tidal power:** the potential energy associated with tides can be harnessed by building a barrage or other forms of construction across an estuary.
- **Tidal (marine) currents:** the kinetic energy associated with tidal (marine) currents can be harnessed using modular systems.
- **Wave power:** the kinetic and potential energy associated with ocean waves can be harnessed by a range of technologies under development.
- **Temperature gradients:** the temperature gradient between the sea surface and deep water can be harnessed using different ocean thermal energy conversion (OTEC) processes.
- **Salinity gradients:** at the mouth of rivers, where freshwater mixes with saltwater, energy associated with the salinity gradient can be harnessed using the pressure-retarded reverse osmosis process and associated conversion technologies.

None of these technologies is widely deployed as yet. Tidal barrages depend on conventional technology, but only a few large-scale systems are in operation worldwide, notably the 240 MW La Rance barrage in France, which has been generating power since 1966. Other smaller projects have been commissioned since then in China, Canada and Russia. The 254 MW Sihwa barrage (South Korea) is due to become operational in 2011 (IPCC, 2011).

Tidal and wave power have been under development since the 1970s. Many design concepts are still being researched, and the leading ones have now reached the point where megawatt scale installations are being demonstrated, and initial deployment plans involving arrays of devices are being developed. Although devices are under development in many countries, a concentration of effort in both development and demonstration is under way in the United Kingdom, and particularly in Scotland. Also dedicated efforts are being made in the New England region of the United States and the province of Nova Scotia in Canada.

A significant potential exists for these technologies. Tidal projects produce variable, but highly predictable, energy flows. Generation from wave power will be variable, depending on the sea state. The engineering challenges associated with efficiently intercepting energy from wave or tidal power are significant, particularly given the need to survive and operate in difficult conditions. Other issues that need to be considered include impacts on marine life, the marine environment and other marine users such as shipping, fishing industry, etc.

Projects involving OTEC have so far been restricted to relatively small-scale applications, although plans and design efforts have been aimed at larger installations. Salinity gradient technology is still at the R&D and pilot plant stage (The Engineer, 2011).[7]

[7] For details see http://www.iea-oceans.org/.

Current market status

The production of energy from ocean-based systems is so far dominated by the La Rance barrage, which produced 491 GWh in 2009. Capacity for other wave and tidal devices in Europe is estimated at 5.9 MW. Significant capacity also is present *e.g.* in Canada (20 MW).

Plans exist for scaling up deployment of wave and tidal power. The Renewable Energy Action Plans developed by EU countries to show how they will meet their obligations under the EU Renewable Energy Directive indicate that a total of 2.1 GW will be deployed in the European Union by 2020 (ECN, 2011).

Costs and cost trends

Cost estimates indicate that wave and tidal power are currently not competitive, but have the potential for cost reduction. A report to the UK and Scottish governments (DECC, 2011a) indicates that, although wave power costs in 2020 are expected to be between GBP 177/MWh and GBP 253/MWh, these costs could fall to between GBP 71/MWh and GBP 101/MWh by 2050. The analogous analysis for tidal stream technologies estimates that costs could fall from GBP 141-250/MWh in 2020 to GBP 82-166/MWh by 2050, with the technologies becoming commercially mature by about 2035. As important as reducing the cost of electricity generation is reaching technological maturity and reliable operation of ocean energy technologies..

Current policy environment

Given the status of wave and tidal developments, the focus of many efforts is on supporting R&D and pilot testing of projects. To assist testing of devices at scale, the United Kingdom has supported the development of two test sites (the European Marine Energy Centre in Orkney, and the Wave Hub off the southwest coast). These sites provide facilities for testing devices at scale under real sea conditions, and have proved popular with developers.

Financial support for deployed devices is provided for wave and tidal via some tradable green certificate (TGC) and feed-in tariff (FIT) schemes.

- In Scotland, power from tidal stream devices receives three renewable energy certificates per MWh (together worth about GBP 170), and wave devices receive 5 ROCs/MWh. In the rest of the United Kingdom and Northern Ireland, electricity from wave and tidal projects receives 2 ROCs/MWh;
- Portugal has introduced a feed-in tariff of EUR 260/MWh for wave power.
- The province of Nova Scotia (Canada) has recently introduced a FIT of CAD 0.652/kWh for small-scale tidal energy as part of its COMFIT programme.

To further encourage deployment, some countries are establishing development zones for wave and tidal projects. The UK Crown Estate, which owns the rights to sea-bed exploitation around the United Kingdom, has approved leases for 1.6 GW of wave and tidal projects around the Pentland Firth and Orkney Islands. Portugal is developing a pilot zone that is able to accommodate projects with a capacity of over 250 MW.

IEA projections and mid-term potential

Relatively few reliable estimates are available of the global potential for the marine energy technologies. The *IPCC Special Report on Renewable Energy* (IPCC, 2011) notes the wide range of estimates of potential: from a theoretical potential for ocean energy technologies of 7 400 EJ/yr to 7 EJ/yr. These ranges are not surprising given the relatively immature state of technology development. Future development will help firm up conversion efficiencies and geographical constraints to practical deployment. The IEA Implementing Agreement on Ocean Energy gives the following potentials:

- tidal power: 300+ TWh/year (ca. 1 EJ);
- tidal (marine) currents: 800+ TWh/year (ca. 2.9 EJ);
- wave power: 8 000 to 80 000 TWh/year (30–300 EJ);
- temperature gradients: 10 000 TWh/year (ca. 35 EJ); and
- salinity gradients: 2 000 TWh/year (ca. 7 EJ).

In the IEA *Energy Technology Perspectives 2010*, the global electricity generation from ocean energy reaches 552 TWh in the year 2050 in the BLUE hiREN scenario (IEA, 2010b). The study carried out for this publication estimates the 2030 technology of ocean and marine energy technologies at 870 TWh (3.1 EJ).

Analysis and prospects

Wave and tidal technologies are at the point where the first deployment activities are under way; therefore, the technologies are emerging from the demonstration into the deployment inception phase in a few leading markets. Future prospects will depend on the leading devices successfully demonstrating reliable performance under testing conditions, and on the ability to demonstrate that the projected cost reductions can occur. Achieving these goals will require projects at scale, involving arrays rather than single devices. This stage will also require very considerable funding from private and public sector sources in the form of capital support, along with enhanced revenue support while the technologies emerge from the initiation stage and enter the market development phase. Providing facilities for testing devices at scale has proved to be a successful spur to development. In addition, because these technologies are being newly introduced into the marine sector, governments can aid the process of development and deployment by establishing a coordinated licensing, regulatory and approval regime to avoid non-economic barriers unnecessarily holding back progress.

Solar energy

Solar photovoltaics

Technology overview

Solar photovoltaic (PV) systems directly convert solar energy into electricity. The basic building block of a PV system is the PV cell, which is a semiconductor device that converts solar energy into direct-current electricity. PV cells are interconnected to form a PV module, typically up to 50 to 200 Watts. The PV modules, combined with a set of additional application-dependent system components (*e.g.* inverters, batteries, electrical components, and mounting systems), form a PV system. PV systems are highly modular; *i.e.* modules can be linked together to provide power ranging from a few watts to tens of megawatts (IEA, 2009a).

The most established solar PV technologies are silicon-based systems. More recently, so-called thin-film modules, which can also consist of non-silicon semiconductor material, have become increasingly important. Although thin films generally have a lower efficiency than silicon modules, their price per unit of capacity is lower. Concentrating PV, where sunlight is focused onto a smaller area, is on the edge of entering full market deployment. Concentrating PV cells have very high efficiencies of up to 40%. Other technologies, such as organic PV cells, are still in the research phase.

Solar PV combines two advantages. On the one hand, module manufacturing can be done in large plants, which allows for economies of scale. On the other hand, PV is a very modular technology. It can be deployed in very small quantities at a time. This quality allows for a wide range of applications. Systems can be very small, such as in calculators, up to utility-scale power generation facilities.

Compared to concentrating solar power (CSP), PV has the advantage that it uses not only direct sunlight but also the diffuse component of sunlight, *i.e.* solar PV produces power even if the sky is not completely clear. This capability allows the effective deployment in many more regions in the world than for CSP.

Because PV generates power from sunlight, power output is limited to times when the sun is shining. However, because sunlight can be predicted with more accuracy than wind patterns, solar PV is less challenging than wind power to be integrated into the energy system.

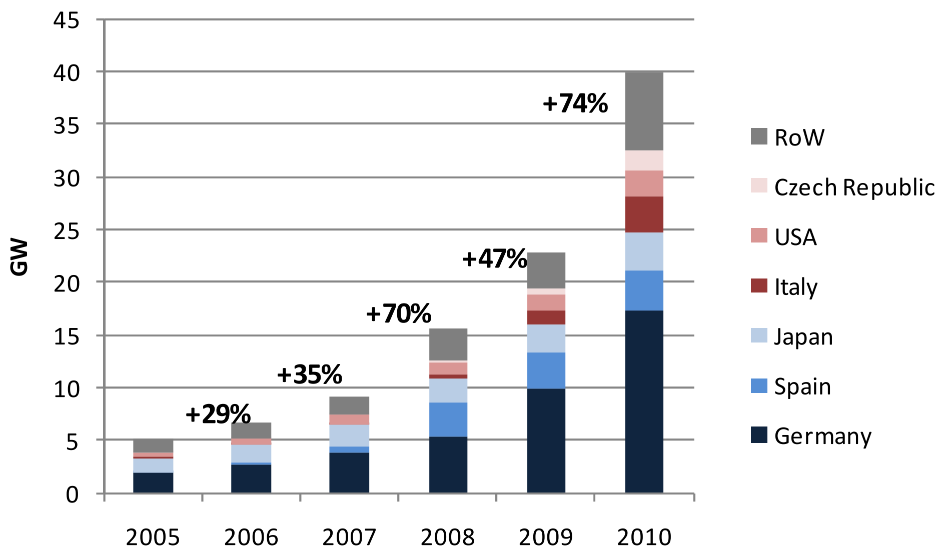
Up to now, the comparably high cost of PV installations has been the main barrier to mass deployment.

Current market status

From 2000 to 2010, in terms of the annual rate of market growth, solar PV was the fastest-growing power technology worldwide. Estimates suggest that cumulative installed capacity of solar PV reached roughly 40 GW at the end of 2010, up from 1.5 GW in 2000 (Figure 6.1). At least 17 GW were added in 2010, about 7.4 GW alone in Germany. Based on first available data for 2010, Germany maintains its massive lead of the market. Italy and the Czech Republic also saw a solar PV boom, resulting from generous FITs and rapidly decreasing costs. Preliminary data for 2011 suggests that Italy took the position as the largest PV market from Germany, with an added capacity above 7 GW in 2011.

In 2009, the last year for which a full data set is available, Germany, Spain, Japan, the United States, Italy and Korea accounted for over 90% of global cumulative capacity.

Figure 6.1 Global installed PV capacity, 2005-10



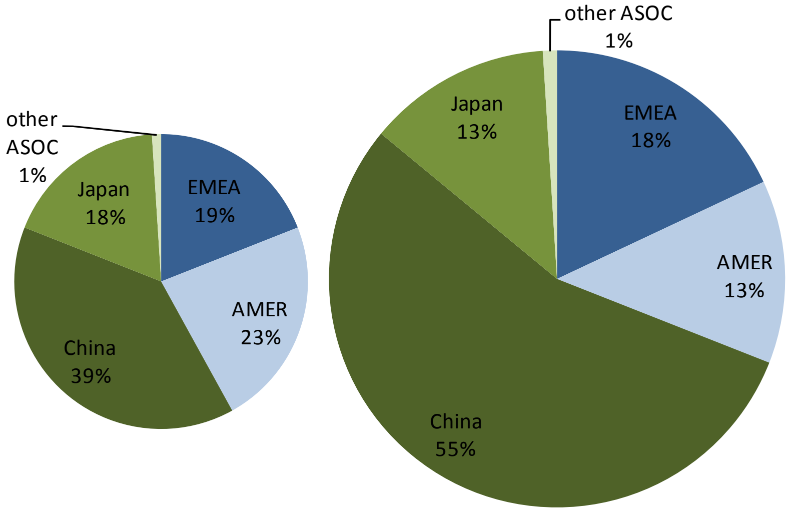
Source: Derived from IEA data and IEAPVPS (International Energy Agency Photovoltaic Power Systems Programme, 2011); BP (2011); BNEF (2011a); ErDF (Électricité Réseau Distribution France, 2011); BNA (2011).

Key point: The large increase of global PV capacity since 2005 has been restricted to a small number of countries.

Growth in the United States remained stable, while Japan continues to lead the way in Asia, adding almost 500 MW in 2009. China has announced ambitious targets, and over the next few years, China is likely to transform its role from a leader in PV manufacturing to accelerate domestic deployment.

The regional distribution of PV module *production* shows a very different trend. China has become the world's largest manufacturer for solar modules. It increased its share in global production from 39% in 2009 to 55% in 2010. Cell manufacturers in other countries, especially those with company headquarters in the United States, lost market shares: the contribution from American manufacturers decreased from 23% in 2009 to 13% in 2010. The overall production grew from 7 517 MW in 2009 to 18 097 MW in 2010 (Figure 6.2).

Figure 6.2 Evolution of market shares in PV module production in 2009 (left) and 2010 (right)



Notes: Absolute production in 2009 was 7.5 GW and 18.1 GW in 2010. EMEA: Europe and Middle East, AMER: Americas, ASOC: Asia and Oceania. Allocation to region according to company headquarters' location; chart area proportional to market size.
Source: BNEF (2011b).

Key point: In only one year, the PV module production more than doubled, with China taking a larger share of the market.

Costs and cost trends

Depending on insolation levels, electricity from PV is competitive now in many off-grid and remote situations, and is coming close to being competitive with retail power prices in favourable markets, which have high insolation levels and high peak power prices. In most markets, however, a considerable price gap still exists, so deployment is still dependent on financially supportive policies.

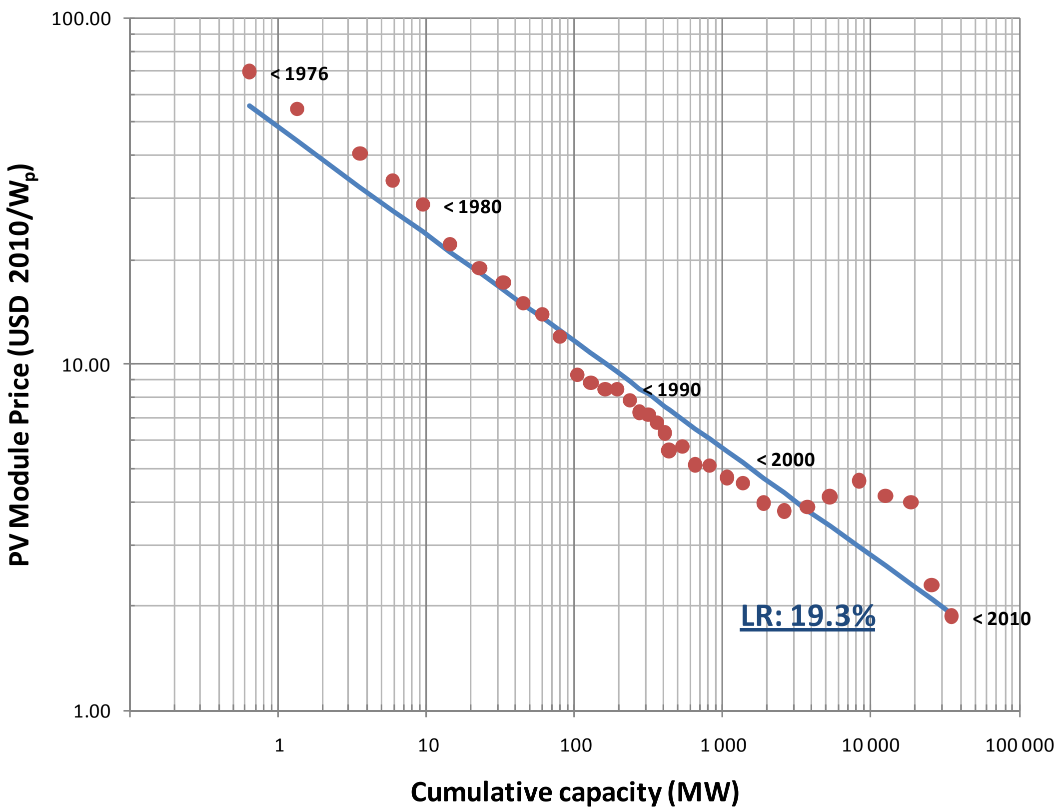
Current spot market prices for solar modules are between USD 1.80/Wp and USD 2.27/Wp for crystalline modules and between USD 1.37/Wp and USD 1.65/Wp for thin-film modules (pvXchange, 2011). Prices vary significantly between markets, however. Total system costs (in June 2011) are between USD 3 300/kWp and USD 5 800/kWp for rooftop systems and between USD 2 700 /kWp and USD 4 100/kWp for ground-mounted systems (IEAPVPS, 2011; BSW [Bundesverband Solarwirtschaft], 2011). Note that these costs are decreasing quickly and may well be out of date at the time of publication. The resulting generation costs depend on cost of capital and insulation. Taking the above system costs, levelised costs of electricity will range between ct USD 11.3/kWh and ct USD 48.6/kWh for ground-mounted systems and ct USD 13.8/kWh and ct USD 68.8/kWh for rooftop systems.[8]

The costs of PV have been falling consistently over the last three decades, exhibiting a learning rate of 19.3% (i.e. a reduction in cost of 19.3% for every doubling of capacity) (Figure 6.3). Such trends can be expected to continue, given the scope for performance and cost improvements delivered by development efforts, as well as significant benefits from scaling up manufacturing processes.

[8] Assumptions: project lifetime of 20–25 years, 6.5% discount rate, full-load hours 850–2200, operation and maintenance 1% of investment costs.

With continuing supportive policies in an expanding number of countries, the cost reduction trends are likely to be maintained, and PV is expected to be cost competitive in some favourable markets, at least compared to retail electricity prices, by 2013. Also, to date, the main markets for PV have been in countries that do not have a particularly good solar regime. Germany, for example, has about half the solar insolation compared to North Africa. If cost reduction trends continue, and the technology is deployed increasingly in these latter markets, PV may be deployed without particular financial support measures in an increasing number of regions and countries, and around 2030, PV should also be competitive with wholesale electricity prices.

Figure 6.3 Cost degression of solar PV modules, 1976-2010



Source: Breyer and Gerlach (2010).

Key point: Historically, every doubling of installed capacity coincided with a 19.3% reduction of PV module prices.

Current policy environment

Most countries with favourable solar deployment have adopted an integrated policy approach by establishing national solar missions or programmes to set targets and drive co-ordination. The most frequently used and successful tools for supporting solar PV have been feed-in tariffs as part of a comprehensive policy approach (IEA, 2011a). These policies, coupled with the significant reductions in module prices, have been able to effectively stimulate rapid increases in capacity.

The levels of FITs have generally been calculated so as to offer a reasonable rate of return to investors in particular markets. To provide investor confidence, these levels have been guaranteed for fixed periods. The rapidly falling PV system costs, however, have meant that the rate of return for investors has rapidly increased. The FITs have usually not been linked to a capacity cap, and few planning or other constraints are in place to hold back the deployment of PV systems, or make them visible at the planning stage. In several markets, capacity has risen much more quickly than intended, and policy makers have been taken by surprise.

The rapid market growth, along with high feed-in tariffs, has also made the costs of the policies a major challenge. "PV bubbles" appeared in Spain (2008) and the Czech Republic (2010). These markets grew massively, leading to excessive costs that, in turn, provoked drastic policy changes. Other countries have been struggling to contain overall support costs and guide deployment on a sustainable path (*e.g.* Germany), while yet other European markets (Italy) are still showing excessive support levels and signs of overheating (Box 6.1).

IEA projections and mid-term potential

The technical potential for solar is very large, because the amount of radiation energy received from the sun is several orders of magnitude greater than global primary energy consumption. According to the analysis of solar PV potential carried out for the current publication, the mid-term potential for solar PV in all focus countries is 5 275 TWh of generated electricity. This number reflects system integration constraints. If regional integration (for example between Northern Africa and Europe) were achieved on a large scale, the potential would be several times larger.

In the 450 Scenario, the IEA *World Energy Outlook* projects a global installed PV capacity of 748 GW in 2035. The total electricity generated from PV is estimated at 838 TWh (IEA, 2010a). This total corresponds to 8.7% of global installed capacity and 3.7% of generated electricity. The IEA *Technology Roadmap: Solar Photovoltaic Energy* (IEA, 2009a) projects an annual market of 105 GW in 2030 and an installed capacity of 900 GW that contributes 5% to total electricity generation. The deployment dynamics of solar PV, however, are hard to track and an art to predict. For example, if the same amount of capacity is added in 2011 as in 2010 (which is an extremely conservative assumption), the global PV capacity at the end of 2011 will have already exceeded the 2010 *WEO* projection for 2015 in the New Policies Scenario.

Analysis and prospects

The development of PV capacity, stimulated by supportive policies in a relatively small number of countries, has been rapid and accompanied by impressive reductions in prices. PV is now cost-competitive in some stand-alone applications. If capacity continues to grow, PV can be expected to become competitive with retail power prices and eventually with wholesale prices in an increasing number of markets over the next 10-20 years. This change will open up the possibilities for deploying the technology in a much wider range of countries, many of which have a rich solar resource and in which PV costs will be lower than in some of the current markets such as Germany.

Currently, though, PV applications are not in general cost competitive. If markets are to grow, economic incentives need to be in place. Experience shows that FIT schemes are an effective policy tool, but also that care has to be exercised in the detailed design of the policy so as to avoid run-away markets, when costs reduce more rapidly than policy makers have anticipated. This potential trend should be seen as a problem stimulated by success, or a "growing pain". By taking advantage of the accumulated policy learning, it should be possible to design policies that effectively stimulate capacity and generation in a predictable way while constraining policy costs to an affordable level. Policies need to be able to react rapidly to changing circumstances. Governments or regulators facing the prospect of so-called "PV bubbles" are right to progressively reduce incentives to match current and expected investment cost evolution, leaving developers with a reasonable, but not excessive, rate of return. Policy makers can also consider having a cap on capacity available at particular FIT rates, so as to constrain the overall policy costs within an expected envelope.

In addition, international coordination of deployment will be a key element in making PV growth sustainable. Spreading out the global market on more countries will ease the financial burden of financing the learning curve of PV, and help to avoid the damaging market reactions when markets in any one major market become constrained.

Box 6.1 Rapid growth in solar PV markets: PV bubbles

Larger-than-expected amounts of PV have been installed in a number of countries that have used FITs as the main instrument to promote deployment. These unexpectedly booming PV markets are causing difficulties for policy makers and stakeholders, and are creating tensions and a lively debate regarding the cost of support policies. The debate has spilled across to other renewable support policies, although the problem is essentially confined to PV because of its characteristics as discussed below.

Difficulties first became visible in **Spain** in 2008, when installed capacity reached 4 GW, almost 10 times more than the official target at that time. In **Italy,** PV accelerated in 2010, with 3.45 GW cumulative capacity in 2010 and 4 GW awaiting connection (GSE [Gestoredei Servizi Elettrici], 2011).

By December 2010, **France** had approximately 0.97 GW installed and another 4 GW in the pipeline (which together represent almost 100% of the 2020 target), although new legislation has put constraints on the support eligibility of some of these projects depending on the phase of the project development reached in early 2011. The **Czech Republic**, with 1.9 GW cumulative installed capacity in 2010, is already above its 2020 1.7 GW target, according to CEPS, the national grid operator. In **Germany,** some 7.4 GW were installed in 2010. Although the growth rate exceeds that which would be consistent with the 2020 targets (about 3.6 GW/year), the German PV installed capacity targeted for 2020 is very large (52 GW) compared to installed capacity at the end of 2010 (17.3 GW). Thailand experienced similar problems. The introduction of a generous and uncapped feed-in premium, combined with a decline in PV system costs, led to an explosion of solar project applications. Applications in 2010 totalled 3.6 GW, more than six times the 2020 target of 550 MW.

Four considerations can help explain the PV boom and these related "PV bubbles":

- PV is extremely modular, easy and fast to install, and accessible to the general public.
- PV investment has been sold both as a green investment at the *individual* level, and as a financial product. Hundreds of thousands of individuals have been offered PV project returns of about 7%-9%.[9] PV was and still is commercially promoted as a long-term, risk-free, green investment instrument. At the same time, abundant equity has been available. Compared to this investment alternative, government bonds would yield between 2.5% and 5%.
- In addition, central monitoring of the rates of such installations is difficult, and system operators may have limited real-time information and means of controlling installation of PV plants, at least in some countries.
- PV suffered excessive incentives in some countries, providing unnecessary returns.

[9] In the case of Germany, rooftop or small commercial installations account for 60% of new installed capacity in 2010, and 97% of all plants.

Generous incentives, inconsistent with declining PV costs, have been and still are available. This situation has allowed for intermediaries to appear in the PV development business, because projects allow for relatively high returns. As a result, final investors harnessed reasonable returns, while intermediaries captured excessive remuneration. Incentives failed to adjust quickly enough to technology improvement and cost reductions. Although the market recognised how PV costs have been dropping sharply, regulation often did not follow a similar path. Potential market changes were not considered *ex ante*, and remuneration levels remained too high.

PV growth has been concentrated in a limited number of markets. Roughly 70% of cumulative global capacity is located in a small number of countries: Germany, Spain, Italy and the Czech Republic. Such a concentration of large global PV deployment in only a few markets inevitably leads to spikes in incentive costs, *i.e.* “PV bubbles”.

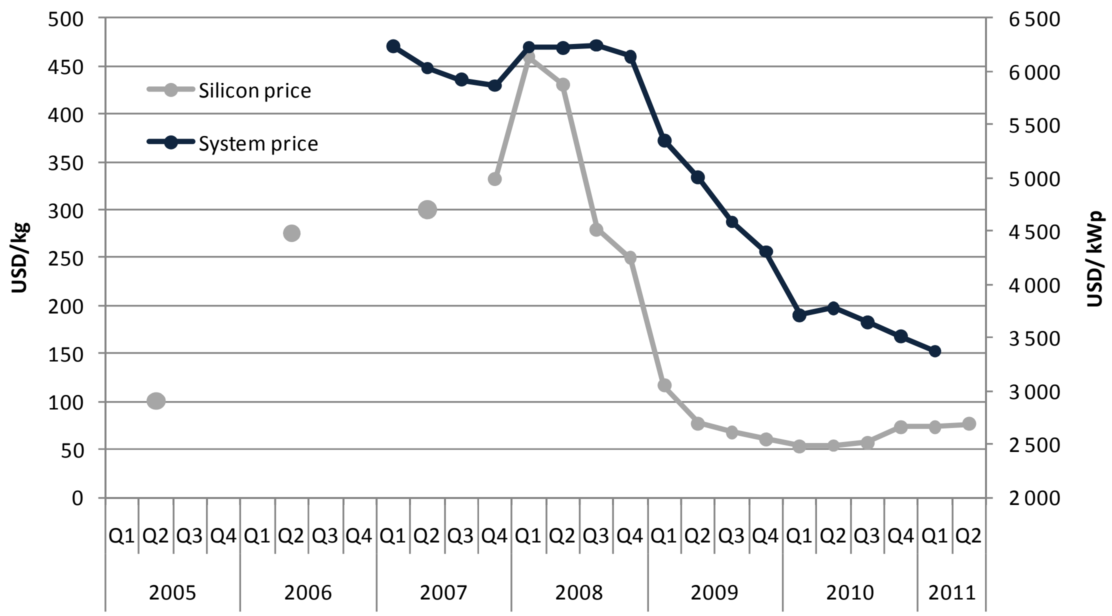
Renewables, and PV in particular, are also a relatively “new” industry, and all agents, including policy makers and regulators, face a learning curve. Some changes in the ways that policies are framed are necessary to provide an environment conducive to a growing market, while avoiding over-stimulating the market and leading to much higher-than-expected policy costs.

Supply and demand of components cannot be expected to keep in step during this inception phase, so deployment rates and costs can be expected to get out of equilibrium at some points. The situation that has led to the problems described above in Spain and other markets could well be exceptional and linked to some details of the regulations that were in place in Spain in 2007 (Real Decreto 661/2007), the strong market in Germany in 2009, and a supply shortage of solar-grade polysilicon.

In Spain, the Royal Decree 661/2007 came into force in May 2007. It contained a target of 371 MW of cumulative installed capacity for solar PV installations receiving a FIT, and 500 MW receiving a FIT premium. The law further included a provision that, once 85% of this target was reached, only those installations that registered in the following 12 months would receive the original incentive level. This provision triggered an installation rush of more than 3 000 MW in the following 12 months. This surge in development put pressure on PV module and component supply, which coincided with an already existing supply shortage of polysilicon. The shortage was exacerbated by strong PV module demand from Spain and Germany. Spot market prices for polysilicon peaked in Q1 2008, some three months after the onset of the Spanish PV rush (Figure 6.4).

At this point, the collapse of the Spanish market went hand-in-hand with the removal of the bottleneck in silicon supply and with new production capacity coming on-line. The market for PV systems reacted as can be expected. System costs decreased very quickly during 2009 (by about 20% in one year). Such a quick decrease had not been anticipated by regulators. Not surprisingly, markets took off where demand was not capped. This trend was true, especially in Germany, as well as in the Czech Republic.

Figure 6.4 Spot market prices for solar-grade polysilicon and evolution of German PV system retail prices



Note: Prices exclude VAT, Exchange rates USD/EUR 2005: 0.805, 2006: 0.797, 2007: 0.73, 2008: 0.684, 2009: 0.7198, 2010: 0.755, 2011: 0.755.

Source: Derived from IEA data, BNEF (2011c) and BSW (2011).

Key point: The peak of polysilicon prices occurred in Q1 2008. During 2008, PV system prices in Germany remained constant and saw a strong decrease in 2009.

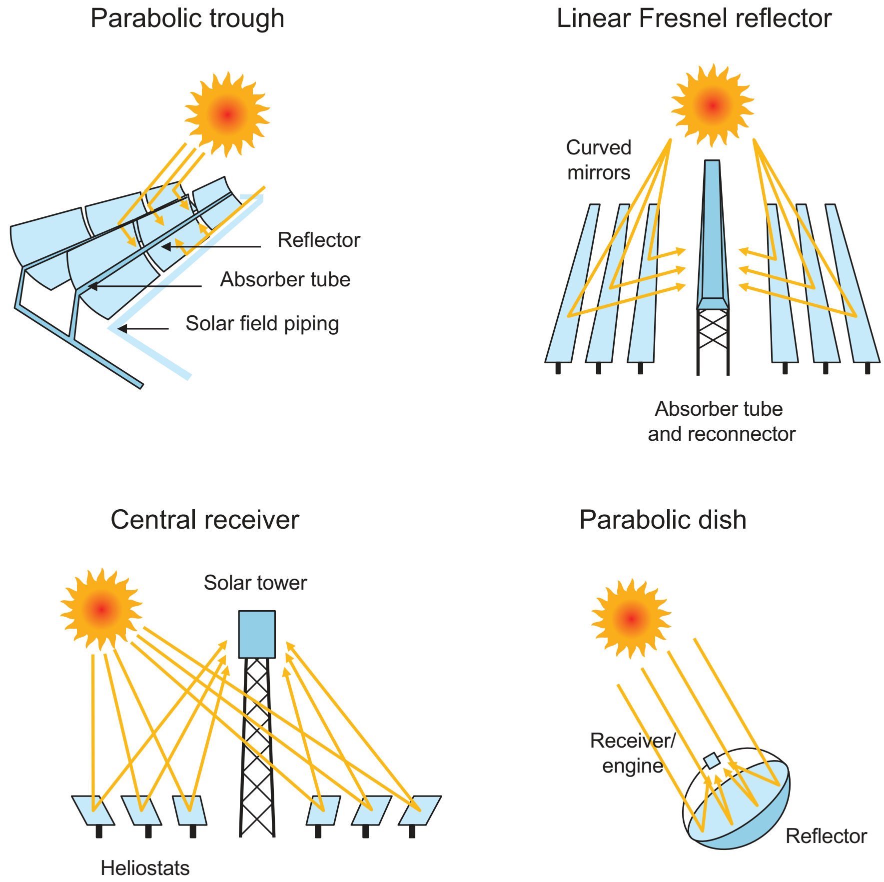
Concentrating Solar Power

Technology overview

Concentrating solar thermal power and solar fuels technologies produce electricity and possibly other energy carriers ("fuels") by concentrating solar radiation to heat various materials to high temperatures. A concentrating solar power (CSP) plant comprises a field of solar collectors, receivers, and a power block, where the heat collected in the solar field is transformed into mechanical energy, then electricity. In between, the system must include one or several heat transfer or working fluids, possibly heat storage devices and/or back-up/hybridisation systems with some combustible fuel. A cooling system, wet or dry, completes the description of the plant (IEA, 2010d). CSP plants come in four different versions: parabolic trough, linear Fresnel, tower and parabolic dish systems.

Parabolic trough systems consist of parallel rows of mirrors (reflectors), curved in one dimension to focus the sun's rays. **Linear Fresnel reflectors** (LFRs) approximate the parabolic shape of trough systems, but they use long rows of flat or slightly curved mirrors to reflect the sun's rays onto a downward-facing linear, fixed receiver. **Solar towers**, also known as central receiver systems (CRS), use hundreds or thousands of small reflectors (called heliostats) to concentrate the sun's rays on a central receiver placed atop a fixed tower. **Parabolic dishes** concentrate the sun's rays at a focal point propped above the centre of the dish. The entire apparatus tracks the sun, with the dish and receiver moving in tandem. Most dishes have an independent engine/generator (such as a Stirling machine or a micro-turbine) at the focal point (Figure 6.5) (IEA, 2010d).

Figure 6.5 Types of solar thermal power plant collectors



Key message: Four different designs are available for CSP receiver systems.

CSP has an inherent capacity to store energy in the form of heat for short periods of time (typically hours) for later conversion to electricity. When combined with thermal storage capacity, CSP plants can continue to produce electricity even when clouds block the sun or after sundown. CSP plants can also be equipped with backup power from combustible fuels. These factors give CSP the ability to provide reliable electricity that can be dispatched to the grid when needed, including after sunset to match late evening peak demand, or even around the clock to meet baseload demand. CSP can also be utilised for seawater desalination by partially using either the generated heat or electricity.[10]

CSP requires strong *direct* irradiation, *i.e.* a clear sky, because only direct sunlight can be concentrated on a small area. As a result, adequate CSP resources are concentrated in a number of key countries in semi-arid, hot regions. Plans have been introduced, however, to transfer the electricity produced from CSP in desert areas to population centres.

As with other thermal power generation plants, CSP requires water for cooling and condensing processes. CSP water requirements are relatively high: about 3 700 l/MWh for parabolic trough and LFR plants (similar to a nuclear reactor or coal plant) compared to about 680 l/MWh to 1 900 l/MWh for combined-cycle natural gas plants. As a result, accessing large quantities of

[10] Note that not all desalination technologies need heat as an input. Reverse osmosis technologies use electricity, which can be generated from other sources. For example, the planned large-scale desalination plant in Al-Khafji, Saudi Arabia, will use concentrating photovoltaics as an electricity source.

water is an important challenge to the use of CSP in arid regions, because available water resources are highly valued by many stakeholders. Dry cooling (with air) is one effective alternative used on the integrated solar combined cycle (ISCC) plants under construction in North Africa. This technology reduces water consumption to 100 l/MWh in case of tower systems and 300 l/MWh for trough systems. The technology is, however, more costly to build and reduces operating efficiencies. Dry cooling installed on trough plants in hot deserts reduces annual electricity production by 7% and increases the cost of the produced electricity by about 10%. The "performance penalty" of dry cooling is lower for solar towers than for parabolic troughs and increases with higher ambient temperatures. Dish systems have very low water requirements of 15 l/MWh (IEA, 2010d).

Current market status

Concentrated solar power is a re-emerging market. Roughly 350 MW of commercial plants were built in California in the late 1980s. Activity started again in 2006 in the United States with the addition of a new 64-MW parabolic trough plant. In Spain, cumulative capacity stood at 350 MW at the end of 2010. At present, Spain and the United States are the only two countries with significant CSP capacity, so the global total was approximately 764 MW at the end of 2010. Projects are under construction or being planned in a number of developing, emerging and some developed economies, including Algeria, Egypt, Morocco, Australia, China, India, Israel, Jordan, Mexico, South Africa and the United Arab Emirates (Figure 6.6). The figure includes those projects under development that have already been tendered or have a signed power purchase agreement (PPA). The numbers can be seen as conservative, due to possible gaps in regional and project coverage. If all projects listed as under construction and development are built, global CSP capacity will exceed 7.4 GW in 2016. The majority of the projects in the pipeline are trough systems. Some towers are already operational, and others are under development. A large number of dish Stirling systems are also under development.

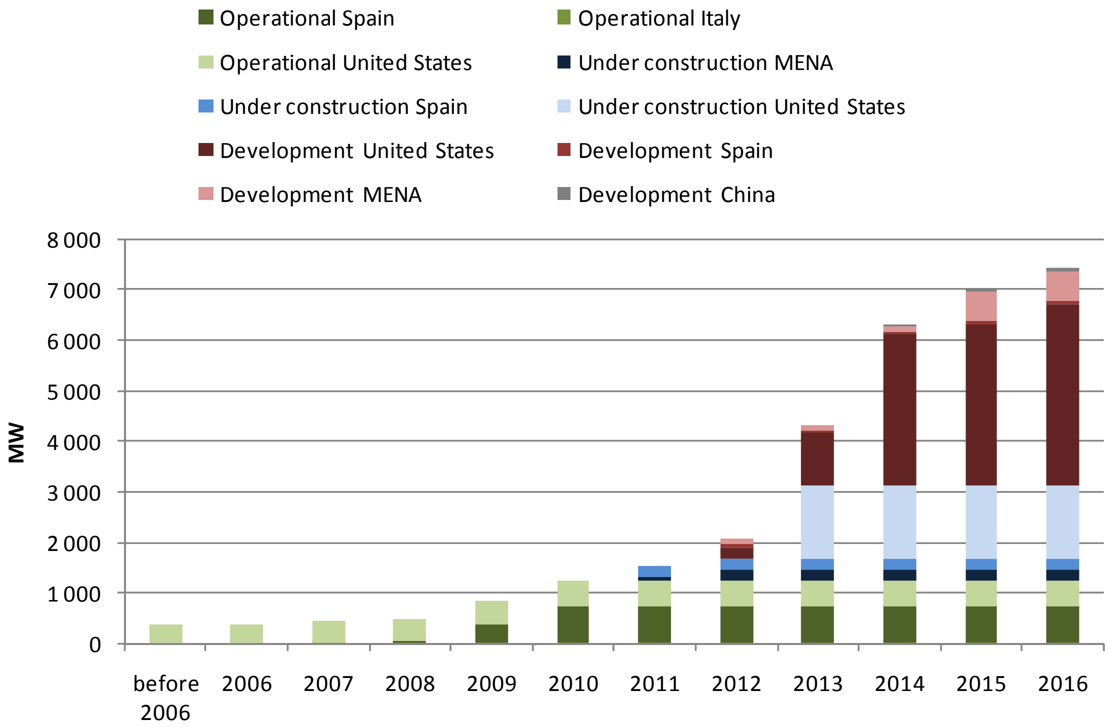
Costs and cost trends

CSP today is usually not competitive in wholesale bulk electricity markets, except perhaps in isolated locations such as islands or remote grids. In the short term, therefore, its deployment depends on incentives.

For large (50 MW), state-of-the-art trough plants, current investment costs are USD 4.2/W to USD 8.4/W, depending on labour and land costs, the amount and distribution of direct normal irradiance (DNI) and, above all, the amount of storage and the size of the solar field (IEA, 2010d). Plants without storage that benefit from excellent DNI are on the low side of the investment cost range; conversely, plants with large storage and a higher load factor but at locations with lower DNI (around 2000 kWh/m^2/year) are on the high side. Depending primarily on capital costs and resource, costs of electricity generation can range between USD 0.18/kWh and USD 0.30/kWh. Storage capacity has comparably low impacts on levelised costs. Storage is incorporated primarily to shift electricity production, not because of its effect on levelised costs.

Investment costs per watt are expected to decrease for larger trough plants, going down by 12% when moving from 50 MW to 100 MW, and by about 20% when scaling up to 200 MW (IEA, 2010d). Costs associated with power blocks, balance-of-plant and grid connection are expected to drop by 20%-25% as plant capacity doubles. Investment costs are also likely to be driven down by increased competition among technology providers, mass production of components and greater experience in the financial community with investing in CSP projects. Investment costs for trough plants could fall by 10%-20% with implementation of direct steam generation (DSG), which allows higher working temperatures and better efficiencies. Turbine manufacturers will need to develop effective power blocks for the CSP industry. In total, investment costs have the potential to be reduced by 30%–40% in the next decade (IEA, 2010d).

Figure 6.6 Global CSP installed capacity and project pipeline, 2011



Note: Projects listed as "under development" have either been already tendered or have signed PPAs. Projects appear at the point of scheduled commissioning.

Key point: If all projects under construction and under development are built, capacity will exceed 7.4 GW in 2016.

Current policy environment

A number of regions, including Spain, Algeria, some Indian states, Israel and South Africa, have put in place feed-in tariffs or premium payments. Spain, for example, lets the producers choose between a tariff of EUR 270 (USD 375)/MWh, or a premium of EUR 250 (USD 348)/MWh that adds to the market price, with a minimum guaranteed revenue of EUR 250/MWh and a maximum of EUR 340 (USD 473)/MWh. This approach has proven effective, because it offers developers and banks long-term price certainty, and makes CSP a less risky investment in the power sector.

In the United States, the federal government recently created the Renewable Energy Grant Program, as well as a Federal Loan Guarantee Program, designed to foster innovation. Bright Source became the first CSP provider to benefit from this programme, securing USD 1.4 billion from the US Department of Energy in February 2010 for several projects.

In the long term, however, financing of CSP plants in the United States may become difficult if investors in technology companies do not supply some equity capital. Prices for capacity and energy are only guaranteed by utilities on a case-by-case basis under renewable portfolio standards (the regulations that require increased production of energy from renewable sources), and these standards are not always binding.

IEA projections and mid-term potential

The technical potential for CSP electricity generation is considerable. According to the analysis of the CSP potential carried out for the current publication, the mid-term potential for CSP in all focus countries is 4 140 TWh of generated electricity. This number reflects system integration constraints. If regional integration (for example between Northern Africa and Europe) were achieved on a large scale, the potential would be several times larger.

In the 450 Scenario, the IEA *World Energy Outlook* projects a global installed CSP capacity of 57 GW in 2035. Total CSP-generated electricity is estimated at 238 TWh (IEA, 2010a). This total corresponds to 4% of global installed capacity and 4% of generated electricity.

Analysis and prospects

Parabolic trough is a proven technology. The first commercial plants began operating in California in the period 1984 to 1991, and are operational still today. A number of world regions have a very large resource potential for CSP.

Targeted policy support in Spain and the United States has triggered an impressive pipeline of CSP projects. The success of these projects will be important in determining the future role of CSP. In other words, the short-term market development is critical for the mid- and long-term prospects of CSP. A stable policy environment and, where needed, targeted support in the form of loan guarantees are important to ensure that a sufficient part of the pipeline gets built. Project developers and the manufacturing industry will then have to demonstrate that they are capable of realising the sharp cost reductions that CSP promises. If this new generation of CSP plants performs well, a larger wave of projects in regions outside of the United States and Spain can be expected to occur, and more countries will be interested in establishing a domestic CSP industry (notably countries in the MENA region). If cost reductions are not as significant as expected, the outlook for CSP is unclear.

Although CSP is, in principle, complementary to PV (because CSP has the ability to balance fluctuating PV production and to generate baseload electricity), the two technologies do compete in some markets. It has taken the CSP community by surprise that PV today has lower generation costs than CSP in some cases. If this gap widens over the next years, CSP will find it more and more difficult to reach a significant market share. The prospects for CSP will depend on the cost of other energy storage options as well as the market value of high-temperature heat, either for industrial processes or water desalination, and the value that is put on hybridisation.

The future of CSP also depends on successful international cooperation. Regional initiatives such as the DESERTEC concept will only become a reality, if a stable regulatory framework can be negotiated between potential exporters and importers. What is needed is a clear political commitment towards importing large quantities of solar-generated electricity from the importing side (*e.g.* in the European Union). Although the European Directive on the Promotion of Energy from Renewable Sources (EU, 2009) contains mechanisms for international cooperation, member states have not yet committed to importing green energy as a strategic option in a sufficiently clear way to stimulate deployment.

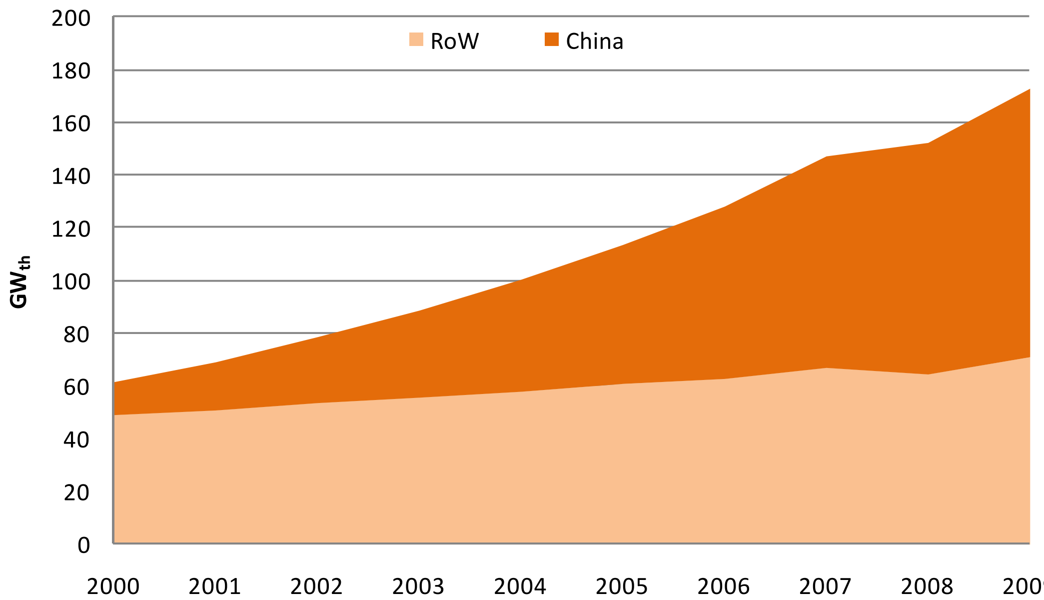
Solar Heating

Technology overview and current market status

Solar heating technologies use solar energy to provide heat. Collectors can be designed to provide heated water at a household scale, but the technology is also being increasingly employed at larger scale to provide hot water for commercial and industrial operations (for example, in the food sector in Austria and other countries) or linked to district heating installations. Several well-developed types of collector are in the market. For water and space heating, flat-plate and vacuum-tube collectors (which dominate the Chinese market) are most popular, with unglazed systems used for swimming pool heating.

The solar thermal collector capacity in operation worldwide at the end of 2009 equalled 172.4 GW_{th}. Between 2004 and 2009, the annually installed glazed water collector area worldwide has almost tripled, and the worldwide average annual growth rate between 2000 and 2009 was 20.8% (IEASHC [IEA Solar Heating and Cooling], 2011). The market has seen a major shift, with very high growth rates in China, where capacity now amounts to 101.5 GW_{th}. Other significant markets are in Europe (32.5 GW_{th}) and the United States and Canada (15.0 GW_{th}). In 2009, the global market grew by 25.3%, with 36.5 GW of newly installed capacity. Of that new capacity, 80.9% was installed in China (29.4 GW_{th}) and 10% (3.7 GW_{th}) in Europe (Figure 6.7).

Figure 6.7 Installed solar water heater capacity, 2000-09



Source: IEASHC (2011).

Key point: Since 2000, mainly China was responsible for global increase of installed solar water heater capacity.

Costs and cost trends

The costs of providing heat from solar collectors are heavily dependent on the solar resource available in a particular location and on the availability of a supply chain operating at sufficient scale to provide low-cost collectors, but in favourable circumstances, the technology can be cost-competitive. A cost comparison of water heaters in China, for example, indicates that, although the upfront cost of solar water heaters is higher than electric or gas water heaters, the average annual cost over the heater lifetime is considerably lower (Table 6.1).

Table 6.1 Cost comparison of water heaters in China

	Electric water heater	Gas water heater	Solar water heater
Hot water supply (litres/day)	100	100	100
Equipment investment (USD)	176	146	264
Annual operating cost (USD)	73	51	0.73
Lifetime (years)	8	8	10
Average annual cost (USD)	95	82	27

Source: REN21 (2009).

Current policy environment

Some countries, such as China and Israel, which both have substantial solar resource potentials, now have high market shares for solar water heating (SWH) systems without relying on continuing incentive support. In China, by 2008, the market share for SWH systems had reached over 50% in urban areas (IEA, 2010a). In 2007, Israel had over 1.3 million solar water heaters, reducing Israel's electricity consumption by 8%. In both these countries, the market was enabled by a combination of concerted R&D efforts, energy efficiency and building regulations, the development of an integrated domestic supply chain and favourable resource conditions, which promoted market-driven growth and major cost reductions for SWH technology (ESTIF, 2007; REN21, 2009). In Israel, due to the solar obligation for new buildings introduced in 1980, solar thermal has reached the critical market size necessary to generate self-sustained growth without any subsidy (ESTIF, 2007).

Some other markets have been stimulated by the use of capital grants. In successful cases, these grants have been backed up by a range of other supporting measures. For example, in Austria, where 20% of all single-occupancy houses have solar heating, solar has been given priority in R&D programmes and strategies for over 20 years, backed up with accompanying socio-economic research and supported by regional investment subsidies. Other complementary measures include solar obligations, which require a certain proportion of heat to come from solar (or a selection of other renewable heat sources). Similar programmes exist in Germany.

IEA projections and mid-term potential

In its 450 scenario projection, the IEA *World Energy Outlook* does not provide a dedicated projection for the contribution of solar thermal heat technologies. In the New Policies Scenario, solar heat demand in the buildings sector is expected to increase from 10 Mtoe in 2008 to 70 Mtoe in 2035.

The technical potential for solar thermal heat generation is considerable. According to the analysis of potential carried out for the current publication, the mid-term technical potential for solar heat in all focus countries is equivalent to 3 300 TWh of heat (12 EJ).

Analysis and prospects

Good prospects exist for wider application of this technology, particularly in sunny climates, where the technology can be financially competitive and deployed without long-term financial support, as shown in China and Israel. Achieving this position requires a package of measures to build confidence in the market and capability in the supply chain, and to push the technology through the initiation and development stages. Building standards have been very successful as a principal tool, as the Israeli example demonstrates. In the case of existing buildings, policies need to address possible split-incentive problems. Usually the proprietor of a residential building shoulders the higher up-front cost, while tenants benefit from reduced operational costs. As with many energy-efficiency technologies, overcoming this type of barrier is key to stimulating deployment.

Wind energy

Onshore wind

Technology overview

Onshore wind power is a proven and mature RE technology that is being deployed globally on a mass scale. Wind turbines extract kinetic energy from moving air flow (wind) and convert it into electricity via an aerodynamic rotor, which is connected by a transmission system to an electric generator. Today's standard turbine has three blades rotating on a horizontal axis, upwind of the tower, with a synchronous or asynchronous generator connected to the grid. Two-blade and direct-drive (without a gearbox) turbines are also available.

The electricity output of a turbine is roughly proportional to the rotor area; therefore, fewer, larger rotors (on taller towers) use the wind resource more efficiently than more numerous, smaller machines. The largest wind turbines today are 5-6 MW units, with a rotor diameter of up to 126 metres. Typical commercial wind turbines have a capacity between 1.5 MW and 3 MW. Turbines have doubled in size approximately every five years, but a slowdown in this rate is likely for onshore turbines, due to transport, weight and installation constraints (IEA, 2009b).

Current market status

Global wind energy production increased by 870% from 2000 to 2009, and by 260% from 2005 to 2009 (Figure 7.1). Globally, wind power has contributed the largest share of non-hydro renewable electricity since 2009, when it took over the leading position from biomass.

During the first half of the decade, Germany, Spain and the United States were responsible for the majority of the increase in deployed capacity and generation. In the case of the United States, deployment followed a series of boom-and-bust cycles.

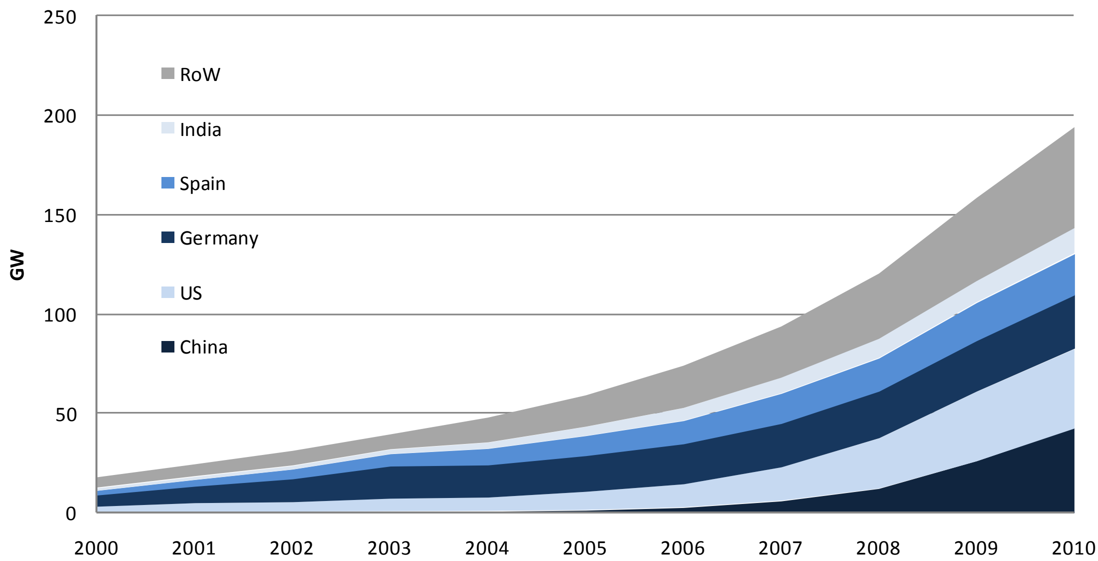
The picture changed, starting from 2005, when mass deployment of wind energy began in China. In 2009, China deployed more wind turbine capacity than any other country in the world (GWEC [Global Wind Energy Council], 2011), and in 2010, half of the new capacity was installed there. At the same time, the number of new installations fell dramatically in the United States, as regulatory uncertainty exacerbated the negative impacts of the financial and economic crisis. Although Chinese capacity figures need to be interpreted with caution (because about 25% of capacity remained unconnected at the end of 2010), the overall trend is clear: the centre of gravity for wind energy markets has begun to shift to Asia, namely to China.

Costs and cost trends

Wind power is among the most cost-competitive renewable energy sources in areas where the wind resource is good. Depending on turbine prices, financing modalities, and environmental factors (such as resource and accessibility of site), the cost of onshore wind power is currently in the range of about USD 40-160/MWh.[11] This makes wind power competitive with newly built conventional generation assets under favourable conditions.

[11] Assumptions: total project costs of USD 1 400 to USD 2 500 per kW, annual operation and maintenance of 2.5% of project costs, full-load hours between 1 800 and 3 500, weighted average cost of capital of 6.5% and a project lifetime of 20 (high cost) to 25 (low cost) years.

Figure 7.1 Evolution of wind installed capacity (including offshore), 2000-10



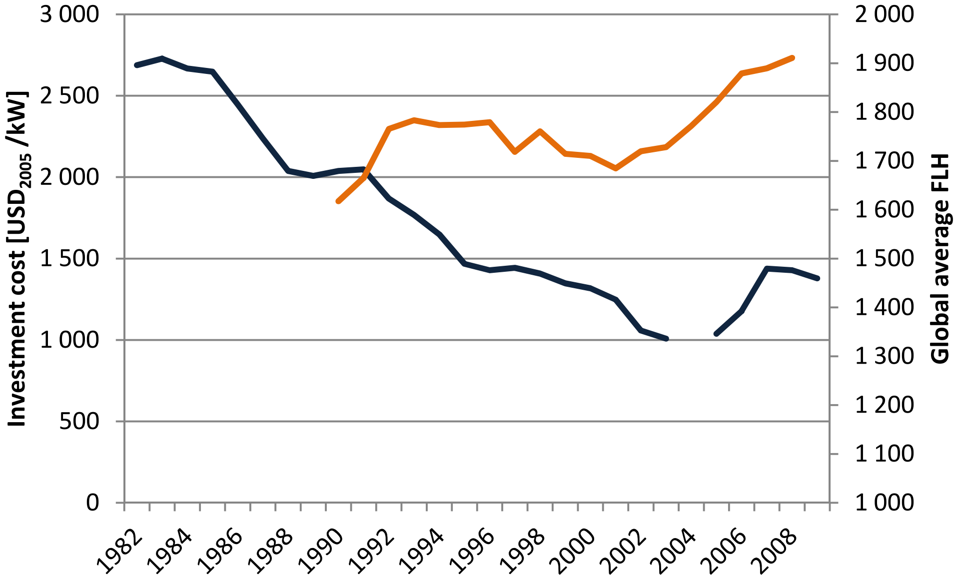
Key point: China became the largest market for wind energy, having outrun the United States in 2009 with respect to newly installed capacity.

Since the start of mass deployment of wind energy in the early 1980s, prices of wind turbines have seen sharp cost reductions that were reflected in shrinking investment costs of wind power projects. Still today, technology efficiency gains are ongoing (Figure 7.2). More improved towers, efficient blades and drive trains, lighter nacelles (rotor plus generator) and fewer components mean a higher electricity output per unit of materials required in the manufacturing process. In addition, the manufacturing process can still be further optimised (IPCC, 2011).

Market conditions, *e.g.* surging demand in times of boom in key markets such as the United States, as well as fluctuations in commodity prices (steel and copper), have a notable impact on turbine prices. In addition, certain manufacturers have a very large share in some national markets, which can lower competition. A number of these factors sometimes counteract the overall downward trend in turbine prices. This effect has led to net increases in turbine costs over some periods, particularly in 2007-09. With the European and American wind markets not performing as strongly as anticipated in 2010, some overcapacity in production has occurred, which has driven down prices most recently. For contracts signed in late 2010 with delivery in the second half of 2011, turbine prices were at USD 1.35 million/MW, down 19% from peak prices in 2007-08 (USD 1.67 million/MW) (BNEF, 2011d).

Under favourable conditions, where the resource is good and regulatory regime is supportive, (*e.g.* in New Zealand and Brazil), wind can now be competitive in electricity markets without special financial support measures. Given continuing capacity growth and electricity generation cost reduction, the number of markets in which wind can compete is expected grow.

Figure 7.2 Investment costs of Danish onshore wind projects (black) and global average full-load hours (FLH) (orange)



Note: Full-load hours are calculated as a four-year running average centred on the year shown.
Source: Derived from IEA data and IPCC (2011).

Key point: Prices for wind power projects decreased sharply since the 1980s but have stabilised in recent years; efficiency has been increasing more quickly in recent years.

Current policy environment

The globally dominant economic support mechanisms for onshore wind energy are FITs. National frameworks differ regarding implementation details, such as whether FITs are paid as premiums on top of wholesale price (also known as feed-in premiums, FIPs), the mechanisms for determining tariff levels and degression, as well as the duration of payments. But all systems share the important aspect that they provide a sufficiently stable remuneration per produced unit of energy. In mature markets, policy developments focus largely around the fine-tuning of the incentive payments. In countries that have a very large penetration of wind (Denmark, Spain and Germany) policy measures also address grid and system integration issues and the replacement of older turbines by more efficient, newer ones.

Another exception to the FIT approach exists in the United States. Here a combination of state-level quota systems, combined with federal tax incentives, provides support for renewable electricity generation. Apart from tax credits, certain renewable energy projects also benefit from advanced depreciation, *e.g.* under the Modified Accelerated Cost-Recovery System (MACRS). On the state level, a number of quota obligations (Renewable Portfolio Standards), sometimes combined with certificate trading, exist. An updated overview can be found in the Department of Energy's Database of State Incentives for Renewables and Efficiency (DSIRE, 2011). Because tax credits directly affect public budgets, this type of support scheme is vulnerable to short-term political volatility. On the other hand, the United States reacted promptly to the problem arising from the drying-up of the tax credit market in 2009, by introducing the Section 1603 cash grant.

Particularly in Latin America, auctions have become an important instrument for developing the wind power market. Emerging economies, such as Brazil and Peru, have lately turned to tenders and reverse auctions to meet their onshore wind energy targets. The winning tariff bids for wind in the recent auctions are significantly lower (by 42% on average), at USD 74.4/MWh, than the tariffs under the earlier FIT-type PROINFA scheme (BNEF, 2010a).

IEA projections and mid-term potential

The technical potential for onshore wind energy is large globally, and wind has a key role to play in a global transition to a sustainable energy system. According to the analysis of potential carried out for the current publication, the mid-term technical potential for onshore wind energy in all focus countries is 5 000 TWh of generated electricity.[12]

In the 450 Scenario, the IEA *World Energy Outlook* projects a global installed wind energy capacity[13] of 1 423 GW in 2035. The total electricity generated from wind power is estimated at 4 107 TWh (IEA, 2010a). This total corresponds to 17% of global installed capacity and 13% of generated electricity.

Analysis and prospects

Wind energy is a mature and proven technology, with mature markets around the globe and an increasingly globalised manufacturing industry. Wind energy is a reliable and increasingly cost-competitive source of clean energy with the potential for further cost reductions. Apart from learning-induced cost reductions, the increased competition with Asian manufacturers entering the market will put downward pressure on turbine prices.

A number of important challenges exist, however, especially when higher penetrations of wind power are attained: (i) the weather-induced variability in output can lead to challenges for the integration of large quantities of wind power into the power system; (ii) public acceptance problems and environmental concerns can hinder the deployment of wind power; and (iii) the emergence of cheap unconventional gas, especially in the United States, has introduced a low-cost option for reaching mid-term climate goals and has put pressure on wind power in the United States, at least for now.

Onshore wind will most likely provide one of the most significant contributions to the global decarbonisation of the electricity sector in the short and medium term. Non-economic barriers such as grid integration, regulatory uncertainty, administrative hurdles, environmental concerns and public acceptance, however, may lead to problems in achieving necessary deployment volumes and rates (IEA, 2011a).

Where policy makers intend to initiate the deployment of wind power, policies for the removal of non-economic barriers (priority access and dispatching of wind power, streamlining of permitting procedures) need to go hand-in-hand with economic incentives. In countries that have already deployed large amounts of wind power, policies need to focus on the system integration of wind power. This system integration includes both technical aspects and regulatory issues. Policy making needs to provide the right incentives to unlock all the flexibility resources of existing power systems and incentives for the build-up of additional resources where needed.

[12] For comparison with the *WEO* 450 Scenario projections, one needs to include the potential for offshore which is estimated at 4 360 TWh in 2030.

[13] This includes both onshore and offshore wind. In the BLUE hiREN scenario (ETP 2010), onshore wind has an installed capacity of 1 167 GW, producing 2 651 TWh of electricity.

Offshore wind

Technology overview

Offshore wind turbines are deployed in the coastal regions. Depending on the depth of the sea, this area can be several tens of kilometres off the shoreline. Deploying turbines in this region takes advantage of better wind resources than at onshore sites. Offshore turbines, therefore, achieve significantly more full-load hours. Offshore wind parks also face less public opposition and lower competition for land. Today's offshore wind turbines are essentially large land turbines with, for example, enhanced corrosion protection. A specific offshore wind industry is developing, however, particularly in Europe, and a specific offshore supply chain is emerging (IEA, 2010b). Future machines will be larger and tailored especially for offshore applications. Turbines will be larger, because the constraints that limit the size of onshore turbines can be relaxed offshore. Individual turbines with capacities up to and beyond 10 MW are already on the drawing board, but still need to be developed and demonstrated. These turbines may include some radical new designs, which are under development but still at the R&D stage (see *e.g.* Carbon Trust, 2008). Because land constraints are not so much of an issue, offshore wind farms can also be large; several planned projects in the North Sea have capacities well over 1 000 MW.

A number of issues, however, make offshore wind projects more challenging and costly than onshore projects, including:

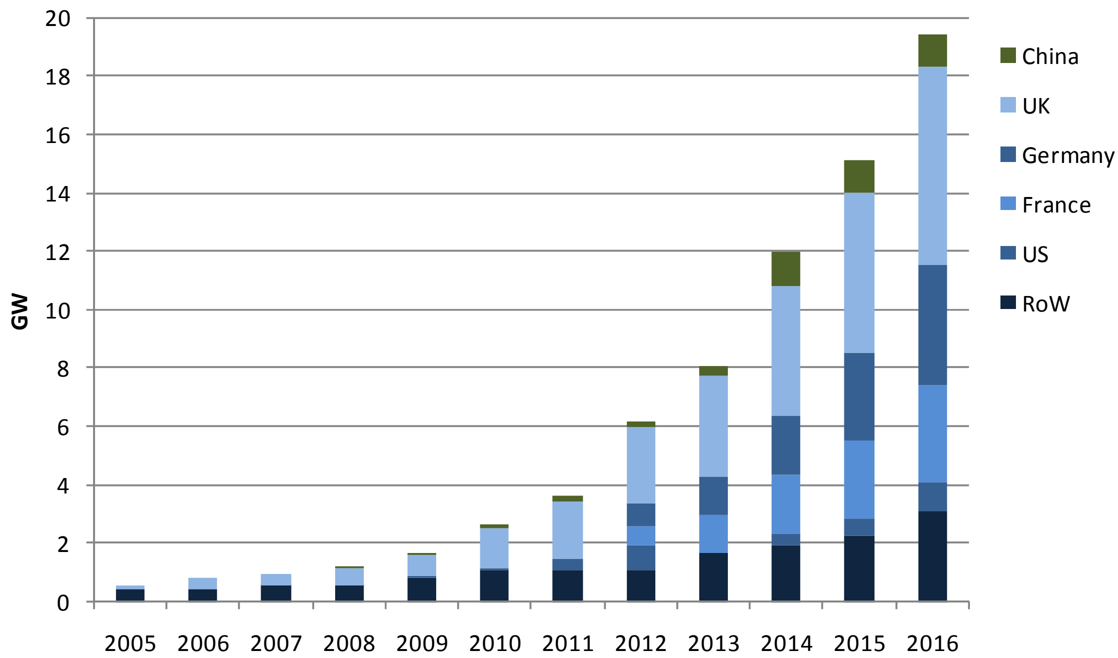
- Support structures for the large turbines need to be provided. Current monopile designs are an economic choice for depths up to 15 metres, and depths up to 25 metres are technically feasible (dena, 2011). Jacket, tripod and tripile designs can access deeper depths up to 50 metres. These constraints restrict where offshore projects can be sited. Wind park sites included in the third round of tenders in the United Kingdom, for example, have depths up to 80 metres. New structures designed for deeper water are under development, such as floating turbines.
- Weather conditions off shore are often difficult and restrict the times when construction and maintenance can occur, and machines must be designed for higher reliability in the challenging marine environment.
- Offshore projects may be sited a significant distance off shore (the Dogger Bank, part of the third round of British offshore tenders, lies as far as 200 km off shore) and, therefore, require lengthy transmission cables and extended transmission systems to connect to power demand centres on shore. Larger-scale projects can reduce the cost impacts of these requirements, and proposals have been made for offshore networks that can be shared by a number of projects, including a proposal for a North Sea Grid that connects several markets.
- Although some siting issues associated with onshore wind projects can be avoided, a number of considerations, such as wind speeds and water depth, must be taken seriously. Environmental issues (such as impacts on the seabed and wildlife, including fish, migrating birds and sea mammals) must be addressed (Lozano-Minguez, Kolios and Brennan, 2011; Bailey *et al.* 2010). The impact on other marine stakeholders (such as the shipping and fishing industries, air traffic control and radar installations) must also be taken into account.

For all these reasons, offshore wind projects are currently more challenging to implement than onshore projects. Because the costs are higher and experience is more limited, projects are seen as more risky technically and commercially. The amount of capital needed for a large offshore park is very high. Financing deals, therefore, include several different players for every deal, which makes it more difficult to reach financial closure.

Current market status

Denmark and Sweden pioneered offshore wind deployment in the early 2000s. Currently, offshore wind is growing rapidly, particularly in the North Sea region (United Kingdom, Germany, etc.). It is one of the major technologies that members of the European Union (in particular, the United Kingdom and Germany but also France and Belgium) intend to rely on to meet their 2020 targets (ECN, 2011). Data on currently developed projects and political targets project a cumulative installed capacity of offshore wind around 20 GW in 2016 (Figure 7.3).

Figure 7.3 Estimated cumulative installed capacity of offshore wind, 2005-16



Note: Market data shown until 2009. Data after 2010 relies on information on currently developed projects and government targets.

Key point: Offshore wind is expected to grow rapidly to 2016.

Costs and cost trends

The investment costs for offshore wind have increased in recent years. In 2003, projects had an estimated project capital expense of USD 1 900/kW installed; in 2010, prices reached USD 4 800/kW. This increase has been the result of: (i) rising costs of input materials, such as steel and copper; (ii) withdrawal of a number of engineering, procurement and construction providers and turbine manufacturers (Vestas during 2006/07); (iii) a crunch in the availability of installation vessels; and (iv) a lack of competition among offshore wind turbine manufacturers (BNEF, 2010b).

The operation and maintenance costs for offshore facilities are also higher than originally expected (in the range of USD 122 400/MW/y to USD 178 000/MW/y). This amount is twice as high as during the first round of offshore project deployments and partially reflects a shortage in O&M providers (BNEF, 2010b).

The estimated levelised costs of electricity (LCOE) generation for offshore projects commissioned in 2010 range between approximately ct USD 0.18/kWh and ct USD 0.19/kWh; other estimates range between ct USD 0.10/kWh and ct USD 0.19/kWh. This figure is bound to increase, however, for projects coming on-line in the near future. LCOE are very sensitive to delays in construction, because early revenues count most in calculating project returns. A project delay of one year translates into an increase of LCOE on the order of 5%-10% (BNEF, 2010b).

The further maturation of the market, especially learning-by-doing effects regarding deployment and increased competition along the offshore value chain, promise future cost reductions. Given the ambitious deployment plans of governments in the United Kingdom and Germany, however, increased demand may be reflected in continuously high prices, similar to what was observed in solar PV between 2000 and 2005.

Current policy environment

A number of recent important policy measures and programmes have emerged to provide support to offshore wind markets. For example:

- The **United Kingdom** has emphasized wind energy in its National Renewable Energy Action Plan (ECN, 2011), with an offshore capacity of 13 GW foreseen in 2020. The plan further states that "Up to 33 GW of offshore renewable generation may be developed." The Crown Estate, which is the owner of the seabed around the United Kingdom, is responsible for assigning leases to developers, and has held a number of "auctions" to allocate concessions. In total, these leases now could provide nearly 40 GW of capacity (The Crown Estate, 2011). The Crown Estate also played an important role carrying out strategic environmental assessments, which have allowed it to focus efforts on areas with favourable wind regime and seabed conditions. These assessments have also helped to avoid major conflicts with environmental and other marine interests, as well as to aid in co-funding the detailed project development costs for projects. The Estate will recover its investments via a levy on power generated by the projects. Current developments are being funded via the UK certificate scheme. Under this scheme, offshore wind projects receive enhanced level of support 2 certificates for installations with additional capacity recognised between April 2010 and March 2014, and 1.5 certificates thereafter (DECC, 2011b) for each megawatt-hour of power generated. To meet capital requirements, funding will be allocated, in part, by the newly created Green Bank.
- Offshore wind also plays a central role in **Germany**'s long-term energy strategy. The government's energy concept, published in late 2010, emphasises the crucial role of offshore wind in Germany's renewable electricity portfolio. According to the National Action Plan on renewable energy, an offshore capacity of 10 GW is foreseen for the year 2020 (ECN, 2011). Offshore deployment will be supported by FITs, as well as a multi-billion loan programme by the German state-owned bank KfW.
- Offshore wind is now a **Chinese** priority, with the publication of its Offshore Wind Development Plan in 2009 and with the National Development and Reform Commission setting up a FIT system.
- In the **United States**, the USD 1 billion Cape Wind project, the first offshore wind farm in the country was successfully approved by the US Department of Interior. The US Department of Energy (DOE) is currently reviewing the Cape Wind loan guarantee application. In December 2010, the US DOE also finalized a deal for the Caithness Shepherds Flat Project, by providing a partial loan guarantee of USD 1.3 billion for the 845-MW wind generation facility located in eastern Oregon. The electricity will be bought by Southern California Edison to comply with California's renewable portfolio standard (RPS) (CPUC [California Public Utilities Commission], 2009).

IEA projections and mid-term potential

The technical potential for offshore wind electricity generation is considerable. According to the analysis of potential carried out for the current publication, the mid-term potential for offshore wind in all focus countries is 4 360 TWh of generated electricity until 2030.

The IEA *World Energy Outlook 2010* does not contain a dedicated projection for offshore wind energy.

Analysis and prospects

Offshore wind has significant potential. The advantages of working off shore (higher wind speeds and fewer siting constraints) will allow larger machines and wind farms, which should improve the economics. These advantages are balanced by the higher costs of installation, more rigorous operating conditions, and impacts of unfavourable weather conditions on access for construction and maintenance. New larger turbines designed to operate under the challenging conditions are under development, along with foundations and platforms that will allow access to deeper sea areas. Although generation costs are currently high, significant potential exists for cost reduction. The renewable energy plans for several countries within the European Union depend heavily on large-scale deployment of offshore wind, and growing interest and activity are evident in other key markets, including the United States and China.

The policy challenges associated with offshore wind include the need to provide financial support for a relatively expensive technology. This support is necessary to start market deployment, build up the experience and industrial capability that will lead to cost reductions, and encourage commercial investment in the R&D necessary to develop new and lower-cost systems and components. Certificate schemes, FITs and other measures are being used to stimulate investment.

A regulatory framework must also be put in place to allow developments to proceed while managing the interests of the other stakeholders in the marine environment (*i.e.* to provide a way of removing unnecessary non-financial barriers while protecting legitimate interests). The UK approach involving the Crown Estate is a good example of an attempt to do this in a concerted way. Developing the necessary grid infrastructure off and on shore also needs to be considered in parallel with the project development, because the timescale and costs associated with this infrastructure are similar to those involved in the offshore structures themselves.

Offshore wind developments are still seen as more risky, technically and commercially, and more reliant on sustained policy support than onshore wind. GW-scale projects involve investments amounting to billions of dollars, so financing is a big issue. The multi-lateral development banks can play an important role during the current stage of development. Once more confidence exists in project performance, and costs come down, funding projects under fully commercial conditions should be easier. For now, though, offshore wind is still at the early deployment stages, and future prospects depend on the demonstration of good performance and significant cost reductions.

Acronyms, Abbreviations and Units of Measure

Region definitions and focus countries

ASEAN-6	Indonesia, Malaysia, Philippines, Singapore, Thailand, Vietnam.
BRICS	Brazil, Russia, India, China (People's Republic of China and Hong Kong), South Africa.
MENA-7	Algeria, Egypt, Israel, Morocco, Saudi Arabia, Tunisia, United Arab Emirates.
OECD-30	Australia, Austria, Belgium, Canada, Czech Republic, Denmark, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Japan, Korea, Luxembourg, Mexico, Netherlands, New Zealand, Norway, Poland, Portugal, Slovak Republic, Spain, Sweden, Switzerland, Turkey, United Kingdom, United States.
LA-2	Argentina, Chile.
SSA-6	Botswana, Ghana, Kenya, Nigeria, Senegal, Tanzania.

International bodies and fora

EU-27 member countries

Austria, Belgium, Bulgaria, Cyprus, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Latvia, Lithuania, Luxembourg, Malta, Netherlands, Poland, Portugal, Romania, Slovak Republic, Slovenia, Spain, Sweden, United Kingdom.

Clean Energy Ministerial (CEM) countries

Australia, Brazil, Canada, China, Denmark, Finland, France, Germany, India, Indonesia, Italy, Japan, Republic of Korea, Mexico, Norway, Russia, South Africa, Spain, United Arab Emirates, United Kingdom, United States.

Group of Twenty (G20)

Argentina, Australia, Brazil, Canada, China, France, Germany, India, Indonesia, Italy, Japan, Mexico, Republic of Korea, Russia, Saudi Arabia, South Africa, Spain, Turkey, United Arab Emirates, United Kingdom, United States, European Union.

IEA member countries

Australia, Austria, Belgium, Canada, Czech Republic, Denmark, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Japan, Republic of Korea, Luxembourg, The Netherlands, New Zealand, Norway, Poland, Portugal, Slovak Republic, Spain, Sweden, Switzerland, Turkey, United Kingdom, United States.

OECD member countries

Australia, Austria, Belgium, Canada, Chile, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Israel, Italy, Japan, Korea, Luxembourg, Mexico, Netherlands, New Zealand, Norway, Poland, Portugal, Slovak Republic, Slovenia, Spain, Sweden, Switzerland, Turkey, United Kingdom, United States.

Acronyms

CAGR	compound average growth rate
CCS	carbon capture and storage
CEM	Clean Energy Ministerial
CHP	combined heat and power
CSP	concentrating solar power
DNI	direct normal irradiance
DDGS	dried distillers grains with solubles
DSG	direct steam generation
EIA	Energy Information Administration
EU	European Union
EU ETS	European Union Greenhouse Gas Emission Trading Scheme
EU-OECD	OECD member countries which are also European Union member states
FIP	feed-in premium
FIT	feed-in tariff
FLH	full load hours
GDP	gross domestic product
GWEC	Global Wind Energy Council
IEA	International Energy Agency
IPP	independent power producer
ITC	investment tax credit
IEAPVPS	International Energy Agency Photovoltaic Power Systems Programme
IEABCC	International Energy Agency Biomass Combustion and Cofiring
IEASHC	International Energy Agency Solar Heating and Cooling Programme
LCA	life-cycle analysis
LCOE	levelised cost of electricity
LR	learning rate
MoU	Memorandum of Understanding
NPV	net present value
n/a	not applicable
OECD	Organisation for Economic Co-operation and Development
O&M	operation and maintenance
PII	Policy Impact Indicator
PPA	power purchase agreement
PTC	production tax credit
PV	photovoltaics
RAI	Remuneration Adequacy Indicator
R&D	research and development
RD&D	research, development and demonstration
RE	renewable energy
RES	renewable energy sources
RES-E	electricity generated from renewable energy sources

RES-H	heat produced from renewable energy sources
RES-T	transport fuels produced from renewable energy sources
RFS	renewable fuels standard
RPS	renewable portfolio standard
ROC	renewable obligation certificate
TCI	Total Cost Indicator
TFC	total final consumption
TGC	tradable green certificate
TPES	total primary energy supply
UNEP	United Nations Environment Programme
WACC	weighted average cost of capital
WEO	*World Energy Outlook*

Units of measure

GWh	gigawatt-hour, 1 kilowatt-hour equals 10^9 watt-hours
ha	hectare
Gt	Giga tonnes
J	joule
kb	kilobarrel
kW_h	kilowatt-hour, 1 kilowatt-hour equals 10^3 watt-hours
kW_p	kilowatt peak
kW_{th}	kilowatt thermal
l	litre
m^3	cubic metre
Ml	million litres
Mtoe	million tonnes of oil equivalent
MWh	megawatt hour, 1 megawatt-hour equals 10^6 watt-hours
PJ	petajoule, 1 petajoule equals 10^{15} joules
Ppm	parts per million
TJ	terajoule, 1 terajoule equals 10^{12} joules
toe	tonne of oil equivalent
TWh	terawatt-hour, 1 terawatt-hour equals 10^{12} watt-hours

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