WORLD ENERGY COUNCIL
CONSEIL MONDIAL DE L'ÉNERGIE
For sustainable energy.

World Energy Perspective

Cost of Energy Technologies

Project Partner: Bloomberg New Energy Finance

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Introduction

The World Energy Council (WEC) and Bloomberg New Energy Finance (BNEF) have partnered to produce a comprehensive comparative study of the costs of producing electricity from a wide range of conventional and non-conventional sources. The aim and the unique value proposition of the study is to provide reference costs based on real project data, focusing on the leading renewables and conventional technologies across a range of regions worldwide.

This is a joint BNEF/WEC report prepared for presentation at the 22nd World Energy Congress in Daegu, Korea (Rep. of). The report covers utility-scale wind, solar PV and solar thermal, marine, biomass, hydro and geothermal. Costs of producing electricity vary significantly around the world and across different energy sources. Any quantitative report or study is as good as the data and other information used for its production. To ensure that this report stands out in the crowded market space of energy related studies, it was very important to have access to the best data available in WEC Member Committees and their member companies. For further work on this topic, stronger support of WEC membership in procuring the required data will be crucial. It could make this project a sustainable top class reference source serving the needs of the entire WEC community. This should be considered a pilot study for upcoming studies with BNEF. We expect that this report will contribute to encouraging more utilities to participate in the next surveys by demonstrating that the benefits of having access to relevant cost information are much higher than the hypothetical risk of confidentiality.

Finally, one technical remark on the Levelised Cost of Electricity (LCOE) values. LCOE demonstrate electricity generation costs only, and thus do not represent the total cost of electricity supply such as grid connection or balancing costs for integration of volatile and intermittent RES (wind, PV). Neither does it include the costs of required back-up capacity based on conventional thermal plants, occasional capacity shedding and other additional system costs.

Technology coverage

The study aims to reflect both the relevant cost ranges for producing electricity from each renewable energy technology as well as the key drivers of projects costs. These include the cost of financing as well as equipment, installation, operating and maintenance and fuel costs where applicable. Four cost metrics are presented for each technology (see Methodology)

- Capital expenditure (CAPEX). This includes the total cost of developing and constructing a plant, excluding any grid-connection charges.
- Operating expenditure (OPEX). This is the total annual operating expenditure from the first year of a project's operation, given in per unit of installed capacity terms.
- Capacity factor. Also referred to as load factor, this is the ratio of the net megawatt hours of electricity generated in a given year to the electricity that could have been generated at continuous full-power operation, or 8,760 full hours.
- Levelised cost of electricity (LCOE): a USD/MWh value that represents the total lifecycle costs of costs of producing a MWh of power using a specific technology.

Note that the analysis only covers projects greater than 1MW in capacity, as the economics of smaller distributed generation – like rooftop PV for example – differ substantially from those of larger projects and the collection of high quality data becomes problematic. For the most mature technologies the cost metrics are generally shown for the following regions, depending on the level of deployment and availability of data:

- US & Canada
- Western Europe
- China
- India
- Japan

Table 1
Technologies covered by this report
Source: Bloomberg New Energy Finance

Class	Technology	Sub-types
Renewables	Wind	Onshore, offshore (excluding grid connection costs)
	Solar PV	Crystalline silicon with and without tracking, thin film
	Solar thermal	Parabolic with and without storage, tower and heliostat with and without storage
	Marine	Tidal, wave
	Hydro	Large hydro >10MW, small hydro <10MW, run-of-river
	Biomass	Incineration, landfill gas, municipal solid waste, biogas
	Geothermal	Binary, flash
Conventional	Coal	
	Gas	
	Nuclear	

Introduction to the levelised cost of electricity methodology

The levelised cost of electricity (LCOE) is the price that must be received per unit of output as payment for producing power in order to reach a specified financial return – or put simply the price that project must earn per megawatt hour in order to break even. The LCOE calculation standardises the units of measuring the lifecycle costs of producing electricity thereby facilitating the comparison of the cost of producing one megawatt hour by each technology. The simple formula for this calculation is shown below and is denominated in USD/MWh, where USD are in 2012 prices:

In practice LCOEs for this report are calculated using a more sophisticated discounted cash flow (DCF) model. This allows us to capture the cost impact of the timing of cash flows, development and construction costs, multiple stages of financing and interest and tax implications of long-term debt instruments and depreciation, among other factors.

The LCOEs presented in this report reflect the actual costs of each technology and exclude all subsidies and support mechanisms. This facilitates a comparison of the total costs of each technology on an equal basis, but does not represent the net costs faced by developers in the market.

The figures used reflect the most recent data available with preference for costs from Q1 and Q2 2013. This is possible for the most widely deployed technologies in larger markets, but for certain technologies where there have been few or no recent installations – such as solar thermal – older figures are used. Costs also exclude the expense of connecting to the grid network, balancing costs and the cost of maintaining adequate flexible capacity in the electricity system to ensure continuous supply as more intermittent, renewable, capacity increases.

Data collection and the WEC network

The data used in this report draws extensively on BNEF's proprietary database of clean energy projects and their associated operating, financing and construction costs. The report has also benefited greatly from the knowledge and data available across WEC's global network. In spite of the good coverage of this report it is acknowledged that some data gaps remain, on both a geographic and technology level. These will be addressed in future editions of this report.

2 Global capacity and levelised cost comparison

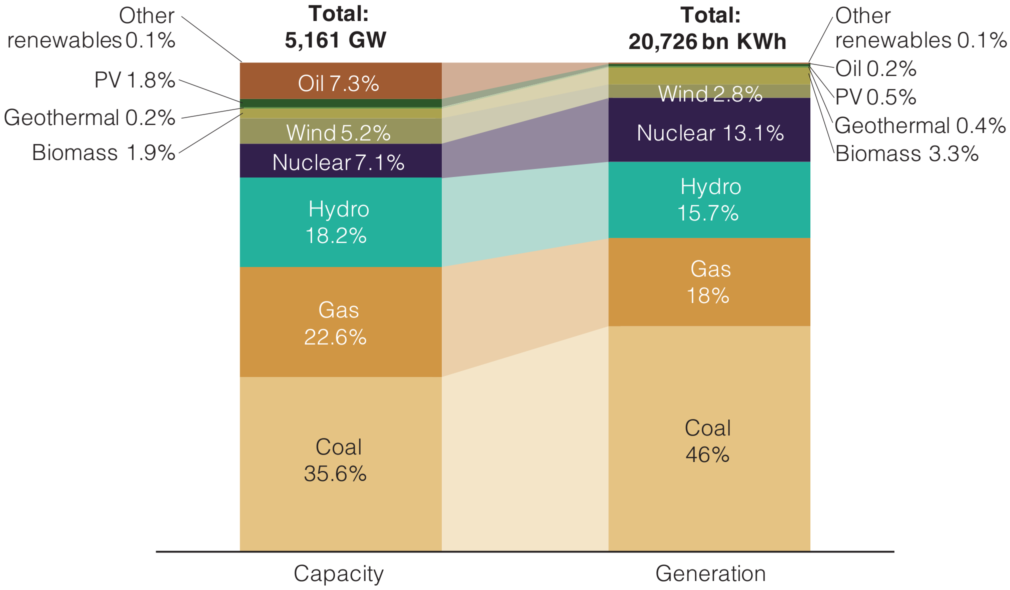
The information below refers only to generation of electricity, and does not present the total cost of supply, i.e. transmission and distribution costs which can often account for a significant share of these total supply costs.

Globally coal is still the king of electricity production, accounting for over 1.8 terawatts of installed generation capacity. Electricity production from fossil fuels – coal, gas and oil – makes up roughly 65% of global power generation, but in 2012 net investment in renewable power capacity outpaced that of fossil fuel generation for the second year in a row (USD228bn for renewables versus USD148bn for additional fossil fuel generation).[1]

Figure 1

Global nameplate installed electricity capacity versus net generation, 2011

Source: Bloomberg New Energy Finance (renewables), EIA (coal, gas, liquids), PRIS (nuclear). Nuclear capacity includes only operational plants, not those defined by the IAEA as being in long-term shutdown.
Note: net generation for 'central producers' as defined by the EIA



However the global share of generation output from renewable technologies is expected to rise from roughly what was 23% in 2010 to around 34% in 2030. Clean energy investments have risen strongly over the past decade, growing seven fold from 2004 to 2011. Wind and solar will continue to dominate. Wind (on and offshore) is projected to rise from 5% in 2012 to 17% of installed capacity by 2030, overtaking large-hydro. Starting from a lower base, solar PV capacity should grow from 2% in 2012 to16% by 2030. A significant amount of this growth is due to the projected decrease in the costs of these technologies – especially for PV – which will see it become cost competitive with conventional sources of power in several markets. This is particularly the case in regions with good solar resources and high power costs (pre subsidy), such as the Middle East. Other renewable sources, such as marine, geothermal and solar thermal, benefit from being more controllable, but will make a smaller contribution than wind and solar due to their higher costs and more limited resources.

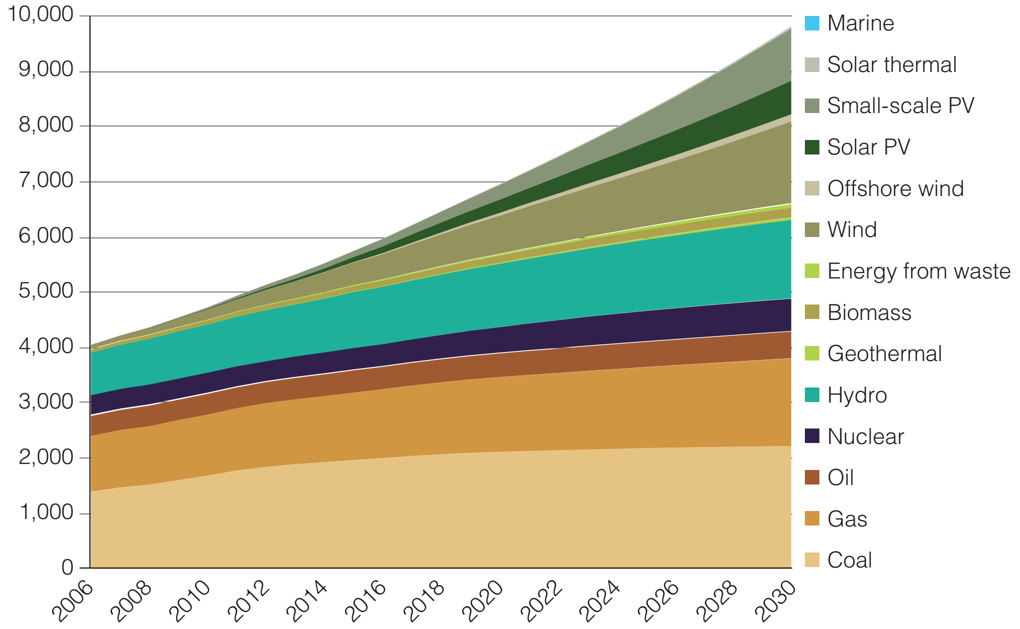
In spite of the growth in renewable capacity, fossil-fuel generation capacity will grow in absolute terms in all scenarios, although its relative contribution will fall from 67% in 2012 to 40–45% by 2030. The growth in coal capacity will slow significantly due to the imposition of carbon pricing schemes and local environmental concerns, especially in terms of air quality. Gas will

1 Bloomberg New Energy Finance/UNEP, Global Trends in Renewable Energy Investment, 2013

continue to increase its share of the global electricity mix, particularly in North America, but the relatively high cost of LNG will constrain the growth of gas as a source of power in Europe, the Middle East and Asia. Nuclear's share is expected to remain steady at around 6%.

Figure 2
Cumulative installed power generation capacity (GW)

Source: Bloomberg New Energy Finance.
Note: forecast is from BNEF New Normal forecast scenario from the BNEF Global Renewable Energy Market Outlook: http://about.bnef.com/presentations/global-renewable-energy-market-outlook-2013-fact-pack-2

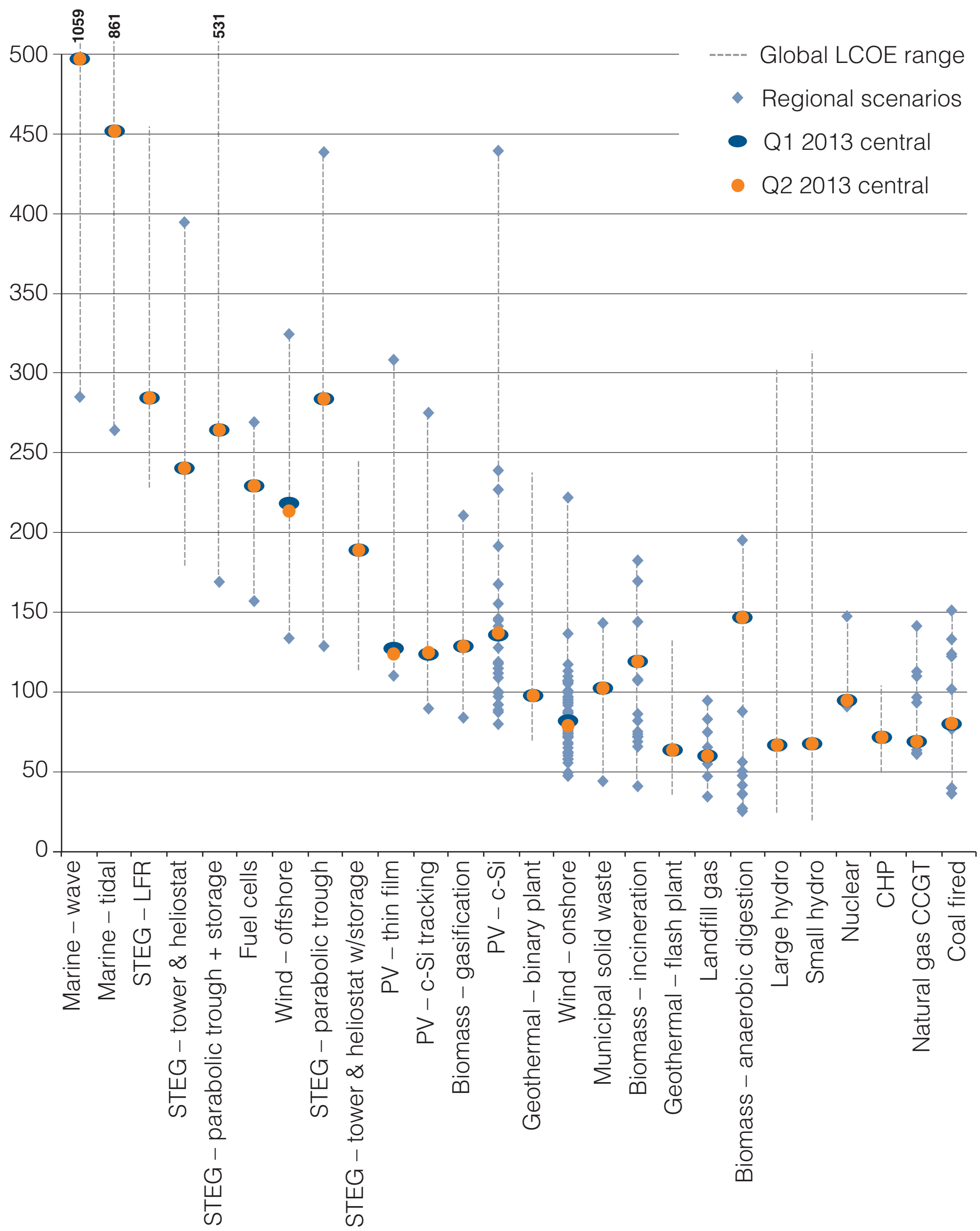


Global LCOE ranges

BNEF already provides a quarterly assessment of global LCOEs for clean and conventional technologies in well developed markets. Figure 3 shows the most recent figures for each technology across the world, as of the beginning of Q2 2013. The LCOE analysis shows that there is a wide cost spectrum across the renewable energy technologies. The more mature clean energy technologies such as hydro and onshore wind, when sited in a good location, fall close to parity with traditional sources, while more emerging technologies such as marine tidal and wave are still at the early phases of cost discovery. Over time the cost of producing electricity from a given technology should fall at a rate related to the level of deployment, a phenomenon known as the experience curve. Over the past few years LCOEs for PV and onshore wind have fallen dramatically as governments have provided financial support that has encouraged rapid deployment, causing the cost of manufacturing those technologies to come down while the efficiency of producing electricity from them has increased.

A key component in the LCOE of renewable technologies is the cost of finance and this varies by technology and location. Typically the more mature technologies of onshore wind and solar PV are accepted as relatively low risk and gain more favorable financing terms. The financing of offshore wind projects however is still highly project specific, depending on the distance from shore, construction technology used and experience of the developer.

Figure 3
Global levelised cost of energy in Q2 2013 (USD/MWh)
Source: Bloomberg New Energy Finance



3

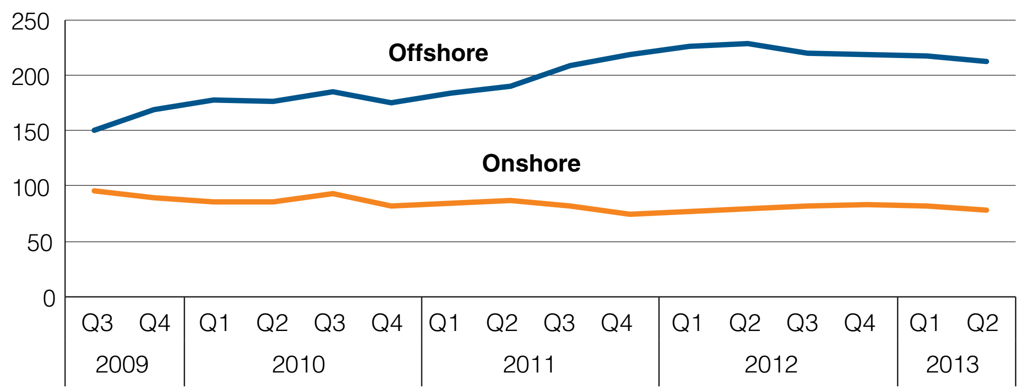
Costs by technology

Wind

Between 2000 and 2010 the global capacity of onshore and offshore wind increased an average of 30% per year, reaching 200GW installed in 2010. 2012 was a record year for new onshore wind installations with over 46GW of capacity built in the year. Offshore wind is just beginning to be installed at scale and BNEF forecasts that by 2020 global capacity will reach nearly 50GW. Regionally, Europe, the US and China account for the bulk of onshore wind capacity while offshore capacity is focused off the coast in Europe with development also occurring along the snore lines of China and South Korea. China will likely be a major force in the future for offshore wind, but delays affecting current projects continue to push out the deployment horizon.

Since BNEF began tracking onshore wind LCOEs in mid-2009, values have fallen by 18%, a rate greater than the turbine experience curve, as a result of increasingly cheaper construction costs and higher capacity factors. Meanwhile offshore LCOEs have crept upwards, reflecting the increased costs of projects further from shore coupled with cost overruns due to harsh construction environments and the complex nature of construction at-sea.

Figure 4
Levelised cost of wind electricity over time, developed market average (USD/MWh)
Source: Bloomberg New Energy Finance



Onshore wind

Core technology costs and performance

Wind turbines make up the single largest component of the CAPEX required for an onshore wind installation, roughly 63% of total cost. The remaining components include concrete foundations, on-site electrical and site-preparation and transport. Depending on a project site's location relative to the manufacturing facility supplying the turbines, transportation costs can cause total CAPEX to increase substantially. The makeup of the global turbine manufacturing industry can be broken into two distinct segments: Chinese manufacturers, which accounted for approximately 40% of supply in 2012 and global manufacturers, which account for the remainder. Manufacturing facilities are spread globally.

Turbine costs, as measured by the Bloomberg New Energy Finance Wind Turbine Price Index, are down nearly 30% from peak prices in 2008, as measured in Euros. A growing split however has emerged between the prices paid for older models versus newer models. Older model turbines continue to decline in price while newer models have become more expensive, reflecting the premium paid for the increased efficiency offered by new turbines. Newer models are targeted specifically at lower resource areas as they are able to extract more energy from lower speed winds than older models. This higher efficiency can result in a lower levelised cost. Certain markets, such as Brazil and parts of Latin America, continue to be dominated by older, less expensive models due availability of high quality wind resources.

Low capital expenditure helps pull down the LCOEs of onshore wind in India and China, making well-sited projects there among the cheapest in the world. The lowest LCOEs for onshore wind can be found in India, particularly in higher wind resource areas such as Karnataka where load factors can exceed 33% and project CAPEX can drop below USD1.1m/MW resulting in LCOEs below USD50/MWh. This is despite some of the world's most costly debt financing: project borrowers can be forced to pay over 1,100 basis points (bps) over LIBOR as the result of a risky lending environment. In China the best project economics can be found in Inner Mongolia, where low domestic turbine prices combined with 35%+ load factors bring LCOEs to around USD48/MWh.

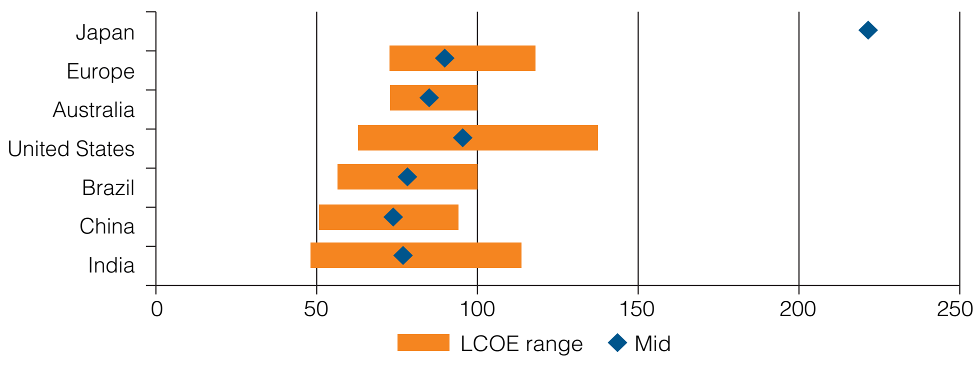
Despite attractive economics there are significant logistical barriers to project installations in these remote regions, as well as the well-documented issue of finished projects being unable to successfully connect to transmission infrastructure. O&M costs for projects in China are not significantly different to those of Western Europe, which relate to the reduced reliability of turbines in the Chinese domestic market that therefore require increased maintenance. Project borrowers in China can expect to pay around 700 basis points over LIBOR for 12 year loans accounting for 75% of total CAPEX.

On the high end globally is Japan – a recurring theme – where exceptionally high equipment costs, a lack of development experience, a competitive market and high OPEX resulting from some of the most expensive labour costs in the world (estimated as a percentage of CAPEX due to lack of data) combine to drive LCOEs up over USD300/MWh. The Japanese market has only just kicked off as of late 2012, driven by a generous feed-in-tariff which has already been reviewed and downgraded.

Figure 5

Levelised cost of onshore wind electricity by region (USD/MWh)

Source: Bloomberg New Energy Finance



In the middle of the extremes lie North America and Europe. All-in CAPEX in the US tends to be slightly more expensive than in Western Europe and comes in at around USD1.8m/MW versus around USD1.6m/MW in markets like Germany and the UK. The developing wind markets of eastern Europe ring in a bit higher, at between USD1.7–1.8m/MW depending on site and shipping. The key LCOE differentiator is load factor. In certain US regions, such as the

Great Plains and parts of Texas, onshore load factors can reach 45%+, putting end LCOEs at USD50 or lower. Finding sites with that level of resource in western Europe can prove challenging, not least because of sheer population density and land unavailability. Load factors for plants with older model turbines average 25%–28% for countries like Germany, Italy and Spain, with parts of the UK able to obtain higher rates. The application of newer models, while increasing CAPEX, can push up averages to 28–31%.

Annual O&M rates are generally higher in Europe than in the US. The UK and Eastern Europe's limited supply chain pushes annual contract charges to USD28,000–29,000/MW/yr, while in more competitive markets like Sweden – that also site larger scale projects able to benefit from economies of scale – costs can drop below USD20,000–USD24,000/MW/yr. The US and Brazil similarly competitive, are both characterised by large–scale projects and O&M contracts of around USD23,000/MW/yr or less.

In BNEF's developed market scenario, a standard onshore wind farm with a capacity factor of 32%, USD1.77m/MW CAPEX and access to 77% debt financing has an LCOE of USD78/MWh.

Table 2
Levelised cost of onshore wind by country

Source: Bloomberg New Energy Finance
Note: *the given range is an average scenario range and does not reflect actual maximum and minimum values

Geography	CAPEX (USDm/MW)	OPEX (USD/MW/yr)	Capacity factor (%)	LCOE (USD/MWh)
India	1.08–1.25	10,694–24,391	15–33	47–113
China	1.36–1.37	17,000–25,138	19–35	49–93
Brazil	1.67	24,000	23–45	55–99
United States	1.83	24,000–24,400	20–46	61–136
Australia	2.27–2.45	33,907	30–42	71–99
Europe	1.61–1.94	23,000–28,750	20–36	71–117
UK*	1.43–1.52	28,750	28–31	72–74
France*	1.43–1.52	20,000–22,500	26–31	75–82
Germany*	1.36–1.46	19,000–21,500	24–27	79–82
Sweden*	1.59–1.71	19,000–21,500	28–33	79–83
Netherlands*	1.44–1.61	20,000–22,500	25–31	79–84
Denmark*	1.51–1.61	20,000–22,500	26–30	80–85
Italy*	1.46–1.6	20,000–22,000	24–30	87–95
Spain*	1.39–1.63	20,000–22,500	26–29	88–91
Poland*	1.52–1.73	23,000–24,500	25–30	93–97
Romania*	1.61–1.85	22,000–24,500	24–30	100–107
Bulgaria*	1.57–1.88	22,000–23,500	24–29	105–106

Policy & financing

Onshore wind new-build in the US is incentivised by the production tax credit (PTC), which is currently due to expire at the end of 2013 after a one year extension in late 2012. Legislative brinksmanship with the tax credit in late 2012 prompted a rush of new installations before December – projects that would otherwise have been built in 2013, leading to a forecasted decline in that market. Financing costs in the US are on par with those in Western Europe: 250–300bps over LIBOR for term loans accounting for 70–80% of project costs at tenors of 8–10 years.

In Europe Germany, Denmark, Spain and the UK are the major markets for onshore wind, but the strong government support of the past has been wavering, particularly in Spain. Developers would perhaps be reassured by clearer policies and greater financial visibility. In Europe, the capacity addition tempo is driven primarily by the attractiveness of government-set feed-in-tariffs, which have been under pressure as austerity measures have been implemented across broad swaths of the continent. Overly-generous support levels in the past have incentivised the construction of projects that would otherwise be very uneconomic. Even recently developed markets aren't immune: Romania slashed its allocation of green certificates to all clean energy projects in June, causing forecasted installations from 2014 forward to fall precipitously. Financing costs in the more stable economies of Western Europe fall in the range of 250–300bps over LIBOR for increasingly shorter 'semi-perm' loans of 5–8 years. This type of shorter-term loan is a reflection of the banking regulatory environment there, which is causing lenders to shorten the duration of the loans and encourage frequent refinancings. In the less-stable markets in Southern and Eastern Europe borrowers can expect to pay 500bps or more over LIBOR as a reflection of high sovereign risk.

China's 2015 wind capacity target of 100GW is likely to be surpassed to the tune of 30GW to a total of 128GW installed, of which 113GW is forecasted to be grid-connected. Grid-connection can be problematic and delays plague the project pipeline. Current estimates peg delays at between 6–24 months/ project with nearly 60% of delays closing in on two years. Grid curtailment issues and financing availability are the main culprits.

In South and Central America wind deployment is focused in Brazil where a government auction scheme has encouraged a recent boom in deployment. Brazilian wind has also benefitted from access to affordable financing from the Brazilian Development Bank, BNDES. Other emerging wind markets in the region, such as Chile and Argentina, have seen small amounts of installed capacity and suffer from relatively expensive equipment and financing costs.

The least developed region for onshore wind is the Middle East and Africa where South Africa, Israel and Kenya lead in terms of installed capacity. South Africa has over 100MW financed, but financing costs can run upwards of 1000bps over LIBOR.

Offshore wind

Almost 95% of the roughly 4GW of global installed offshore wind capacity is situated in the waters off Europe's western coast. Within that region the focal points are the UK and Germany. As a result, offshore wind LCOEs are a function of the costs of just over 50 projects located in that region, and a thorough understanding of how costs differ in other regions will likely result only from additional capacity deployment. This is set to change in the coming years as China, South Korea and other new entrants expand their installed bases. Nearly 2GW of offshore wind came online in 2012, 93% of which was in European waters. By 2020 that figure will be down to 60% and China on its own will account for nearly 30% of capacity installed. Note that offshore wind CAPEX is exclusive of grid-connection charges.

The financing of offshore wind projects differs substantially from that for other renewable sources due to the sheer magnitude of the projects. Most of the projects financed over the past year have been over valued at over USD1bn with two projects over USD2bn. At these sizes complex financing structures are required and many deals involved the participation of numerous commercial banks and one or more multilateral development banks.

Table 3

Levelised cost of offshore wind by country

Source: Bloomberg New Energy Finance

Geography	CAPEX (USDm/MW)	OPEX (USD/MW/yr)	Capacity factor (%)	LCOE (USD/MWh)
Western Europe	4.29–6.08	100,000 –160,000	32–42	147–367

As a percentage of LCOE, O&M costs make up a substantially higher portion of end costs for offshore wind than for onshore wind. The harsh environments inherent at sea and the higher degree of difficulty in accessing sites and transporting equipment are key drivers of these costs.

Turbines are the main component of offshore CAPEX, representing approximately 30–40% of total costs. The market for offshore turbines is much more concentrated that that of onshore, with Siemens alone making up nearly 60% of historical and forecasted installed capacity from 2010–2020. Scale is another major differentiator – turbine sizes for the offshore market can reach as large as 6MW each. Other key drivers are foundations and the cost of installation, which can vary substantially as a function of sea depth. Bottlenecks such as access to installation vessels and construction of offshore grid infrastructure are causing delays in the industry, which increase contingency costs. Grid connection charges vary but can represent around 20% of total CAPEX costs; although for the purposes of this report those costs are excluded.

Tax represents about 25% of the LCOE, which is much higher than the 19% for onshore wind. One of the key drivers here is that it is assumed that onshore wind has greater access to debt financing, which leads to a higher interest expense thereby reducing the tax liability for onshore relative to offshore.

North America has yet to commission any offshore wind projects due to persistent delays in the installation of announced projects and problems crossing legal regulatory and regulatory hurdles. Permissions and incentives to build offshore wind farms depend on the jurisdiction of the water, since different policies may apply in federal or state waters. The 485MW Cape Wind project recently confirmed sale of 75% of its potential output and reached several key financing milestones. Until successful commercial operation of this and other smaller projects it will remain difficult to accurately assess LCOEs in the United States.

The Middle East & Africa and South America are not currently forecasted to be areas where offshore wind will be deployed in the coming decade and as such have been excluded from our analysis.

Solar PV

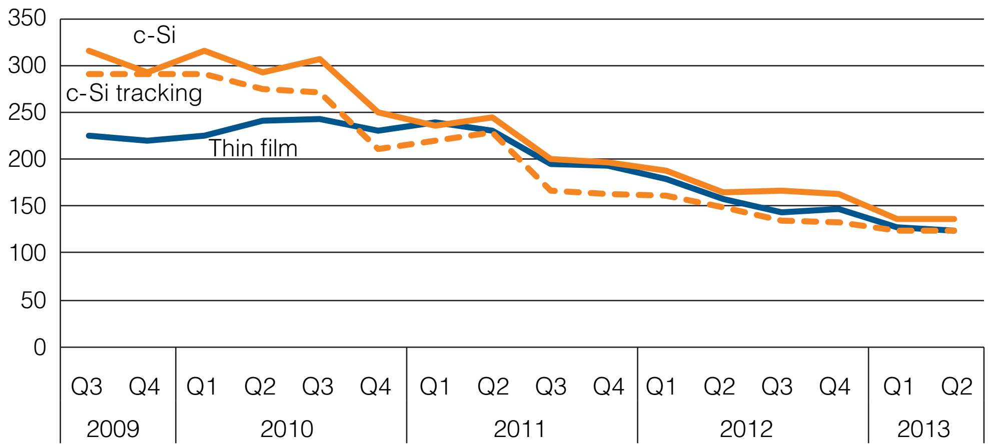
Global installed capacity for PV has historically been dominated by Europe where government incentive schemes have spurred large deployment, for example in Germany and Italy. From 2007–2011 Europe accounted for 70–80% of total installations. That fell to 50% in 2012 and will continue to decline, likely to 20% by 2015, as China and Japan become the growth markets.

The last few years have witnessed more or less consistent declines in the cost of modules and underlying components, pushing LCOEs lower and lower in a market increasingly dominated by Chinese suppliers. PV economics differ substantially between plants >1MW and smaller distributed retail or commercial rooftop plants. For this report we concentrate only on larger projects.

Figure 6

Levelised cost of PV electricity over time, developed market average (USD/MWh)

Source: Bloomberg New Energy Finance



Feed-in tariffs driven growth combined with a rapid fall in module prices have made solar PV more competitive over recent years, spurring a boom in the sector. This rapid growth has prompted governments to scale back feed-in tariffs to avoid budget overshoot.

In markets and locations with more expensive power, such as in parts of Germany, companies are now finding it more cost-effective to use the power from solar cells themselves – referred to as auto-consumption – rather than claim the feed-in tariff. Installation continues there: the country installed nearly 800MW in Q1 2013 and over 1,000MW in Q2 2013 even as feed-in tariffs for new installations fell – driven in part by the trend towards auto-consumption.

With the diminishing prospects in Western Europe attention is now focused on China and Japan, the new main drivers of the global PV market. In China, solar PV has relatively few barriers to growth. It is competitive with conventional energy for commercial users but is more expensive for residential consumers. Here, most of the 35GW capacity target for 2015 will therefore be met by large-scale, >1MW installations and distributed generation in the commercial sector. A 2020 target of 50GW solar PV generation exists, supported by a national feed-in tariff and a system of subsidies. A boom in solar installations is underway in Japan, with the country's new generous feed-in tariffs making solar PV a very attractive prospect. The program has incentivised a large build there, with nearly 800MW of approved capacity as of early Q2.

The US solar market is relatively fragmented at present due to a lack of federal level coordination, ambition and visibility of policy. Few large-scale projects are currently in the pipeline and the focus has shifted to distributed capacity in key markets like California. Deployment is dependent on a tax incentive program that is set to drop significantly in 2017 and expire three years later.

Crystalline silicon (c-Si) PV without tracking

The global nature of the module market means that a project with similar characteristics in Europe and North America can end up costing roughly the same amount to operate. However in Asia, projects in India and China have been able to drop below the USD100/MWh mark due to access to cheaper modules and equipment and lower O&M costs. There is very little deployment of large-scale PV in the Middle East, Africa and South & Central America. Exceptions exist for South Africa – where a new tender program is boosting deployment – and Saudi Arabia – where a newly announced tender round is seeking to fund up to 800MW by the end of the year. One important cost trend is the ability for module manufacturers to sell products at higher prices in emerging markets which benefit from aggressive feed-in tariffs like Japan and South Africa.

The bulk of the capital costs for large-scale PV is attributable to modules, followed by balance of plant costs including mounting and electrical equipment. Inverters account for about 10% of total costs. The most recent BNEF module price index for June 2013 places the values for multicrystalline modules for immediate delivery in Europe at USD0.78/W and in China at USD0.70/W and below. Recent industry turmoil resulting from a chronic product oversupply has led to a significant number of exits from the cell, wafer and module manufacturing industry and has subsequently brought system costs down 57% from 2010 levels. While the industry remains in oversupply prices have leveled and it's unlikely that these types of cost declines will continue into the future.

The wide LCOE ranges for standard PV without tracking reflect major differences in capacity factors based on geography. In Germany a generous feed-in-tariff scheme spurred significant growth in PV installations even in areas with low solar resource. This has driven the upper end of the LCOE range for Europe to over USD600/MWh for projects in northern Europe built in areas with capacity factors as low as 9%. Projects in sunny southern Europe are able to obtain capacity factors of upwards of 18–19%, bringing down LCOEs to just over USD100/MWh.

Low Indian and Chinese LCOEs are driven by a combination of low CAPEX and high quality resource availability. The Chinese domestic market has perhaps the lowest module costs globally as the hyper-competitive market and low labor costs drives down prices. Modules made exclusively for the domestic market can be significantly cheaper than those for export, especially if the product is from a lower tier manufacturer. A fully built up unit in China can go for USD1.4m/MW or less. If that is coupled with a well-sited project in high-sun Inner Mongolia for a capacity factor of 20% or higher, LCOEs of USD80 can be realised. Indian projects run at similar costs, if not slightly higher at around USD1.5m/MW. Projects in high sun areas like Rajasthan and Gujarat are able to hit capacity factors of 19–20% with LCOEs as low as USD85/MWh.

In developed markets a large disparity exists between CAPEX costs in Germany – the key western European market – and the US. The highly competitive and efficient German market has put downward pressure on margins for EPC contracts and a streamlined permitting and siting process means lower upfront costs. This leads to lower total CAPEX versus the US, where margins are still robust and obtaining permits can be a large administrative burden.

Large-scale projects in the US come in at around USD1.8m/MW, while a best-in-class project in Western Europe comes in at about USD1.6m/MW. Costs for the US are banded in a slightly narrower range and projects with single digit capacity factors have largely been avoided. However pricing data suggests that large-scale PV plants currently require a slightly larger capital investment than comparable facilities in Europe, increasing the LCOE. Capacity factors vary widely in both places, with projects achieving anywhere from 12–21% in the US and 11–19%+ in Europe.

Echoing onshore wind, mainland Japan has the highest LCOEs globally (although in certain parts of Okinawa high quality sun resources produce much lower LCOEs). Their generous feed-in-tariff has incentivised construction of plants with low load factors of around 12% coupled with global maximum CAPEX of USD2.7m+, pushing LCOEs to USD430/MWh and higher. Developers there have been too keen to use expensive domestically-made components, partially a result of the fact that Japanese banks have been hesitant to finance projects with a significant amount of foreign-made parts. This can be attributed to a couple of factors – one is because PV project finance of the type European & American markets are used to is relatively new to Japan, and the other is that banks there are worried about the risk foreign manufacturer bankruptcy poses for product warranties. This appears to be changing – partly due to the increase use of reinsurance for warranty risk – and the increasing bankability of cheaper Taiwanese and Chinese parts should help bring down LCOEs.

Figure 7
Levelised cost of solar electricity by region (USD/MWh)

Source: Bloomberg New Energy Finance

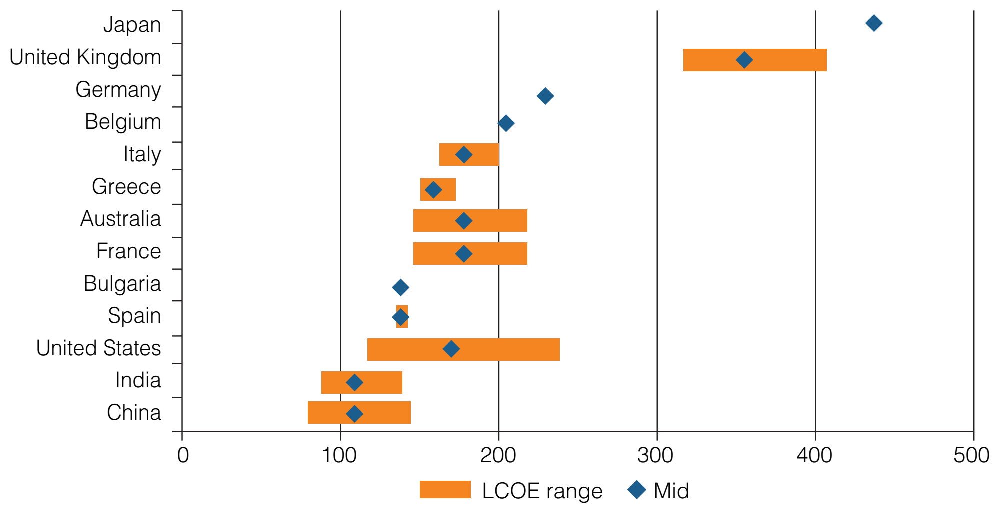


Table 4
Levelised cost of PV by region

Source: Bloomberg New Energy Finance.
Note: *the given range is an average scenario and does not reflect actual maximum and minimum values

Geography	CAPEX (USDm/MW)	OPEX (USD/MW/yr)	Capacity factor (%)	LCOE (USD/MWh)
China	1.45–1.05	17,000	11–20	79–145
India	1.53–1.81	11,063–14,750	15–20	87–137
Spain*	1.63	25,000	19	109
United States	1.77	25,000–60,000	12–21	117–239
Australia	2.41	27,330	14–21	127–191
Germany*	1.63	60,000	11	226
Japan*	2.66	50,000	12	439

Crystalline silicon (c-Si) PV with tracking

Tracking systems are used for projects on sites with high levels of direct sunlight. Gains to the project's capacity factor significantly outweigh the additional expense of the system when sited appropriately, and can subsequently lower the LCOEs. For this analysis we assume the utilisation of a duel axis tracking system which brings the maximum capacity factors up for a given project to just under 30%. Due to a lack of significant detailed information about the types of mountings utilised for tracking plants globally we have based these figures on premiums over PV without tracking, both in terms of the O&M and CAPEX required and the additional capacity gained for each scenario. This means that LCOEs for all regions are ranked similarly to those without tracking but are generally lower due to higher capacity factors.

Table 5
Levelised cost of PV with tracking by region

Source: Bloomberg New Energy Finance
Note: *the given range is an average scenario and does not reflect actual maximum and minimum values

Geography	CAPEX (USDm/MW)	OPEX (USD/MW/yr)	Capacity factor (%)	LCOE (USD/MWh)
Western Europe	2.37–5.03	40,050–99,900	18–29	90–397
US	3.21–6.21	58,725–126,450	16–27	139–449

Tracking systems bring in additional costs of around USD500,000/MW due to the equipment required. The cost breakdown also shifts due to higher O&M costs, meaning that proportionally O&M makes up a higher part of the LCOE for tracking systems than for fixed mounting systems.

Table 6
Levelised cost of PV with tracking by region

Source: Bloomberg New Energy Finance
Note: *the given range is an average scenario and does not reflect actual maximum and minimum values

Geography	CAPEX (USDm/MW)	OPEX (USD/MW/yr)	Capacity factor (%)	LCOE (USD/MWh)
Western Europe	1.60–4.53	26,700–66,600	15–20	99–412
US	2.70–5.71	39,150–84,300	13–22	145–446

Thin film

Current large-scale thin-film plants bear many of the same cost and performance characteristics of c-Si projects, with some products garnering a 1–2% capacity factor advantage in certain climates. Thin film modules currently price at a discount to multicrystalline, coming in at USD0.54/W. Operating costs and all-in CAPEX are largely the same after recent price declines and performance improvements for crystalline silicon modules have led to a convergence. Thin film was originally developed as an alternative to crystalline silicon panels at a time when silicon costs were significantly higher than current market prices. As a result, thin film panels are now priced very similarly to crystalline panels and in a commoditised and well developed supply market, USD/MW CAPEX costs and LCOEs should be very much in line.

Cost estimates for the LCOE ranges are based largely on those for crystalline silicon plants. Estimates for Asia & Oceania were excluded due to a lack of data for that region.

Concentrated PV (CPV)

While still in its infancy a new application of PV is emerging in certain markets with high levels of direct sunlight. Concentrated PV concentrates light into small spots using lenses or mirrors, reducing the area of actual PV cells required to produce power. Currently only about 130MW of projects are operable globally, but around another 700MW are in the pipeline. Price indications show that at suitable sites LCOEs are still higher than duel-axis tracking, but that costs should decline over the next two years to a point where it is competitive at appropriate locations.

Solar thermal

Solar thermal electricity generation (STEG), also referred to as concentrated solar power (CSP), consists of a suite of technologies at varying stages of development and deployment that typically use concentrated solar light to produce steam, either directly or via a heat transfer liquid, which then powers a steam turbine. Spain and the US are the dominant markets for these technologies and account for approximately 4GW of the just over 5GW installed or financed globally. Behind these two leaders are China and India, which combined have financed just over 500MW of projects. Due to the lack of true global deployment our scenarios for STEG consist of two "regions", one that is a grouping of estimates for projects in China and India and the other is for developed markets, which includes the US, Europe and Australia.

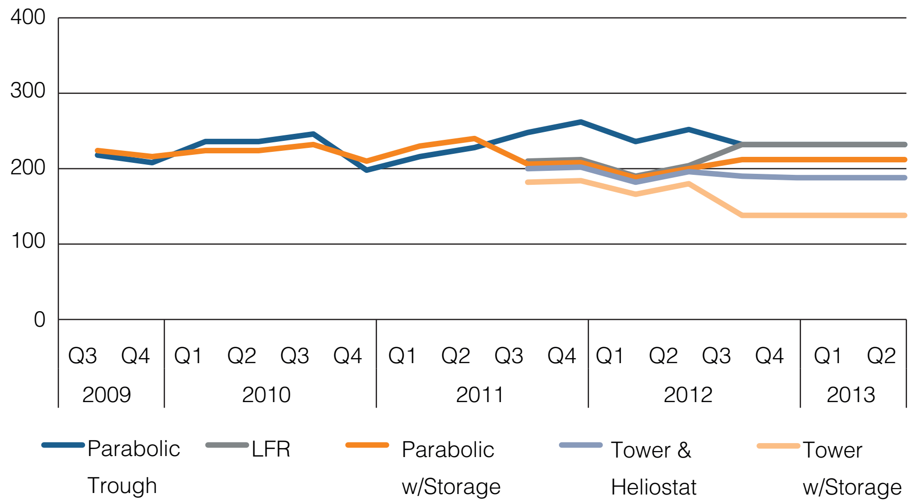
Compared to PV, solar thermal is a newer solar generation technology that generates electricity by capturing the sun's thermal radiation as opposed to through photovoltaic cells. There are multiple sub classes of STEG plants, but currently parabolic trough plants are the most widely deployed, followed by tower and heliostat plants. The economics of solar thermal make it nearly three times as expensive as conventional coal and gas and on average 50% more expensive on a MWh basis than PV. A 2012 analysis suggested that wider deployment over the ten year period to 2022 would likely result in parabolic trough with storage cost reductions to between USD120–150/MWh – versus the current level of nearly USD300/MWh.

Financing activity for thermal plants peaked in 2011 when both Spain and the United States had support mechanisms in place to spur development. After those programs ran their course investment dropped off and has yet to recover. Thus far in 2013 only one project has confirmed financing, a 35MW parabolic trough plant in Chile. As a result of slow financing volumes in a post-subsidy environment it is currently difficult to pinpoint developments in levelised costs for the technologies.

Figure 8

Levelised cost of solar thermal electricity over time, developed market average (USD/MWh)

Source: Bloomberg New Energy Finance



Parabolic trough

Parabolic trough is the most mature of the thermal technologies, accounting for 3.8GW globally. Spain and the US play host to the most important trough markets, but China and India are both developing and financing a number of plants. India's Jawaharlal Nehru National Solar Mission scheme spurred a significant number of financings in India in 2011. In China, there is a strategy to develop domestic solar thermal technologies, which is underpinned a strong pipeline of 500MW worth of projects that were either announced or financed last year.

The solar field component is the largest contributor to total plant CAPEX. The remainder of the capital costs are split between the heat transfer fluid (HTF) and the powerblock. Indirect costs such as project development and large cost contingency buffers are also key drivers of LCOEs for solar thermal projects and account for a large part of the required investment. Parabolic trough plants have been bankable, but almost exclusively when they have also secured access to credit enhancements or low cost finance from government banks and lending schemes.

Parabolic trough plants can be coupled with thermal storage equipment that is able to hold heat for around six hours. The addition of a thermal energy storage (TES) system increases the CAPEX of a plant but also drives up the capacity factor significantly, sometimes to 45–50%. Due to a 50MW size limit on plants in Spain, 62% of that country's parabolic trough plants are coupled with storage as result of developers seeking to maximise their returns. One of the key economic values of storage is that it allows solar thermal to be dispatchable and removes some of the intermittency issues that affect other renewable technologies – a characteristic that is not effectively captured by levelised cost analysis.

Projects in India and China have significantly lower LCOEs both due to lower equipment costs and lower O&M figures. There is a lack of significant development experience in these countries and it remains to be seen if projects in the pipeline are able to come in at budget or if cost overruns are a major problem. Parabolic trough LCOEs are still quite high and can top USD450–500/MWh versus USD165/MWh for PV.

Table 7

Levelised cost of parabolic trough by region

Source: Bloomberg New Energy Finance
Note: *the given range is a average scenario range and does not reflect actual maximum and minimum values

Geography	Type	CAPEX (USDm/MW)	OPEX (USD/MW/yr)	Capacity factor (%)	LCOE (USD/MWh)
Spain, US & Australia	No storage	3.42–7.67	63,340–59,907	24–28	201–490
	with storage	6.00–10.96	61,574–63,700	28–42	156–469
China & India	No storage	3.08–4.55	44,000–45,000	24–28	123–248

Tower and heliostat

There are currently 775MW worth of financed or commissioned tower and heliostat plants globally, versus about 3.8GW of parabolic trough. The plants are spread across a number of markets including the US and Spain but also smaller markets such as Morocco, Saudi Arabia, India, China and South Africa. Tower and heliostat plants use a field of focused mirrors to concentrate light on a central receiver tower in which a heat transfer liquid is circulated, capturing thermal energy. There are varying plant designs and developers choose to utilise two different methods of heat transfer, with some choosing to use the concentrated solar light to boil steam directly and others using a molten salt fluid as a means of transferring heat to boil water.

The heliostat field and power block are the largest direct cost contributors to LCOE, together making up almost 40% of the USD/MWh cost. Indirect costs including contingencies, services and other non-equipment costs account for nearly 26% of the end LCOE.

The addition of a thermal storage system using molten salt has a similar effect on LCOEs as with parabolic trough plants. The addition of a system can provide around six hours of heat storage at an additional CAPEX cost that is offset by a corresponding increase in plant capacity factor that results in lowered LCOEs. A six hour molten salt storage unit accounts for around 6% of the total LCOE, with all other costs remaining essentially the same as a plant without thermal storage.

Table 8

Levelised cost of tower and heliostat by region

Source: Bloomberg New Energy Finance
Note: *the given range is a average scenario range and does not reflect actual maximum and minimum values

Geography	Type	CAPEX (USDm/MW)	OPEX (USD/MW/yr)	Capacity factor (%)	LCOE (USD/MWh)
Spain, US & Australia	No storage	4.08–6.12	68,265–64,714	21–32	167–399
	with storage	6.00–8.66	70,403–117,313	42–64	105–317

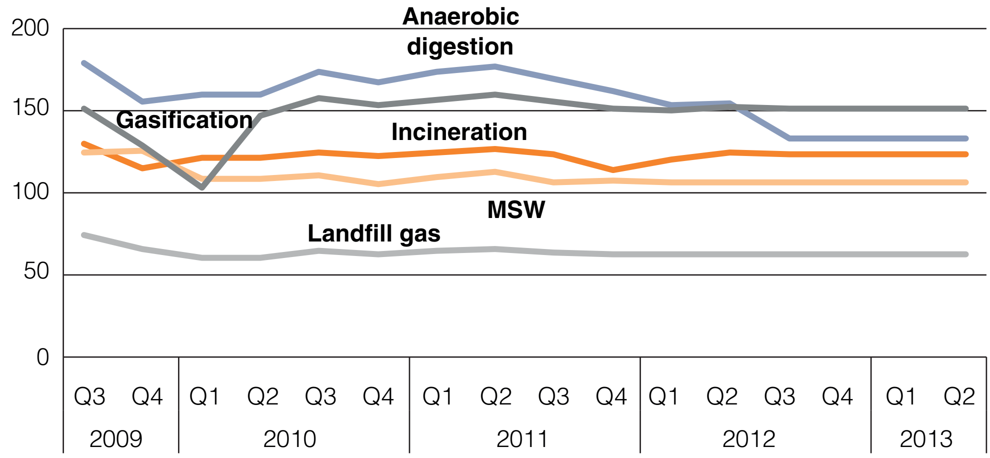
Biomass and Waste

Biomass and waste power encompasses a range of technologies that generate electricity from various biomass feedstocks and either municipal or industrial waste from incineration, gasification or anaerobic digestion technologies. The most common organic feedstocks are residues from the forestry industry, but specially-grown crops, such as willow or elephant grass, are becoming increasingly important. In sparsely wooded areas, agricultural residues like straw or husks are predominantly used. Other means of generating power in this sector harness the methane created from the decomposition municipal or industrial waste. Biomass power economics are more closely related to those of traditional thermal generation, due to their reliance on feedstock inputs. They can also be subject to significant economies of scale.

Western Europe leads the world in terms of installed biomass electricity capacity, followed by the US and Brazil. China has a national target to reach 30GW biomass generation by 2020. National feed-in tariffs and tonnage targets are also in force to support this target. Since a significant part of the levelised cost of biomass generation, the feedstock, is now offset by subsidies, we are likely to see significant growth in line with government targets.

In the US, biomass generation is supported by the regional renewable portfolio standards and the biomass production tax credit. The tax credit is due to expire at the end of 2013 but may be extended for a further two to three years. This policy uncertainty is raising the barrier to obtaining finance.

Figure 9
Levelised cost of biomass electricity over time, developed market average (USD/MWh)
Source: Bloomberg New Energy Finance



Brazil has an abundant, cheap fuel in the form of bagasse, a waste product of sugar processing. The low operational costs of bagasse incineration reduce the levelised costs and are incentivised with stable policy support and transparent pricing.

The UK has seen significant biomass investment thanks to government support schemes. The upcoming Energy Bill is likely to replace the current portfolio standards and feed-in tariffs with a “Contracts for Difference” scheme whose details have yet to be announced.

Incineration

Incineration is the most straight-forward of the biomass generation technologies and involves burning a feedstock to produce heat, boil water and generate steam. Incineration in this report refers only to non-municipal-solid-waste incineration and requires the procurement of feedstocks for combustion. Due to the nature of the biomass feedstock supply chain costs vary depending on location. There are four main categories of feedstocks: agricultural residues, energy crops, forestry residues and wood pellets. Agricultural residues are typically viable feedstocks only when supply sources are located close by due to transport economics (agricultural residues typically have a lower energy density than forestry residues).

In Western Europe the dominant feedstocks are derived from forestry residues and wood pellets. Increasing retirements of coal power plants in the region are stoking increased interest in biomass-to-power incineration, but ensuring a stable long-term supply with price visibility is key to accessing the financing required to develop a plant. In India and Brazil, large sugar processing industries generate substantial bagasse that can be used for incineration.

Biomass incineration capital costs are subject to significant economies of scale: small plants below 10MW can cost upwards of USD5m/MW while larger plants can drop as low as USD1.5m/MW.

Landfill gas

Landfill gas projects tap into the methane generated through waste composition by driving pipes deep within the core of landfills and funneling the gas to generators for burning. Depending on the composition of the landfill, the gas generated is typically around 50/50 methane and carbon dioxide. Projects are initiated prior to the closure of the landfills and consist of vertical wells to collect gas and send it through a scrubber, a compressor and finally to a generator for combustion.

Municipal solid waste

Municipal solid waste (MSW) generation incinerates municipal waste to produce power. The economics of these plants differ from biomass incineration as rather than paying for feedstock the plants actually receive gate fees as revenue for disposing of the waste, which vary with the availability of landfill space and the tipping charges at those locations. The US has around 75 waste-to-energy plants while Europe has more than 400.

Gasification

Gasification technologies turn organic feedstocks into gasses that can be burned to produce power through a process of heating them in an oxygen-constrained environment. Of the four types of biomass technologies included in this report, gasification is the least mature. Gasification plants typically use one of two main technologies: fixed bed or fluidised bed gasifiers.

Table 9
Levelised cost of biomass by region

Source: Bloomberg New Energy Finance
Note: *the given range is a average scenario range and does not reflect actual maximum and minimum values.

Geography	Type	CAPEX (USDm/MW)	OPEX (USD/MW/yr)	Capacity factor (%)	LCOE (USD/MWh)
US	Incineration	2.00–5.40	90,000 –200,000	~85	50–200
	Landfill gas	1.54–2.47	90,000 –200,000	60–90	45–95
	MSW	2.90–7.70	90,000 –200,000	80	80–210
	Gasification	3.60–6.40	90,000 –200,000	80	50–140
Western Europe	Incineration	2.00–5.40	90,000 –200,000	~85	50–200
	Landfill gas	1.54–2.47	90,000 –200,000	60–90	45–95
	MSW	2.90–7.70	90,000 –200,000	80	80–210
	Gasification	3.60–6.40	90,000 –200,000	80	50–140
China	Landfill gas	1.43–2.22	115,000 –266,667	70–90	34–83
India	Incineration	0.83–1.20	27,657–89,885	50–85	65–86

Geothermal

Geothermal taps the naturally-occurring heat stored in rock up to several miles below the surface of the earth. Conceptually, the extraction process is simple: a series of holes are drilled into the ground and the subterranean heat is captured by drawing to the surface the naturally occurring steam or hot fluid. The steam is then run through a turbine directly, or the hot geothermal fluid is used to heat a separate working fluid that converts to a gas to turn the turbine. In both cases, the used geothermal fluid is injected back into the subsurface to aid in replenishing the resource.

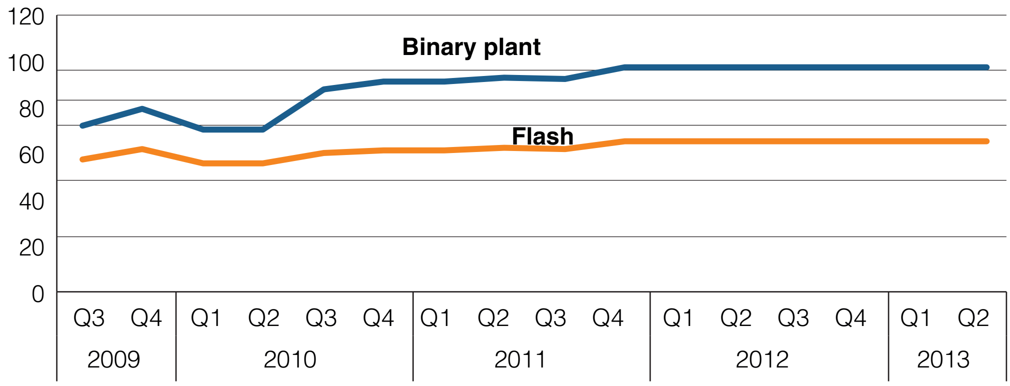
Globally there is just over 11GW of commissioned geothermal, dominated by the US which has 3.1GW, followed by the Philippines with 1.9GW and Indonesia with 1.2GW. The growth pipeline of projects is concentrated in Indonesia, the US, New Zealand and Japan, but Kenya and Ethiopia are also forecasted to be major growth spots for expansion. The size of the resource available in Ethiopia means that there is significant potential for the country to eventually become a net electricity exporter. The introduction of Japan's new feed-in-tariff will likely spur development of geothermal there, but there are long lead times for project development (up to 7 years according to a local industry association). Indonesia's recent move to raise the price ceiling for geothermal projects and the US's last minute extension of its production tax credit (PTC) represent two additional positive signs for further deployment.

Geothermal technologies are relatively mature within the renewables class and as such are subject to different cost drivers than newer wind and solar technologies. Also unlike other renewable technologies, much of a geothermal plant's cost occurs prior to confirmation of resource availability during the process of drilling test wells.

Figure 10

Levelised cost of geothermal electricity over time, developed market average (USD/MWh)

Source: Bloomberg New Energy Finance



Inaccurate resource measurement could lead to under-producing plants and subsequently lower than forecasted revenues. Long development lead times also pose barriers to development. These are caused by the diligence necessary to prove reservoir resource, secure land rights and receive development permits, which can be especially difficult in countries with inefficient regulatory and permitting systems or complex land rights laws.

Drilling rig rates and associated costs make up the single largest cost component of geothermal plants, upwards of 55%, and can increase substantially with drilling failures and vary with the complexity of the well. Day rates for rigs vary substantially based on local rig availability. In the US costs hover around USD20,000/day while in countries like Chile and Indonesia daily rates can be upwards of USD40,000/day for a global average of USD28,000/day. Geothermal projects compete with oil & gas projects for the same rigs, so a booming oil & gas sector can end up meaning more expensive drilling costs for geothermal.

Binary

Binary plants are the most recently developed geothermal technology and are able to tap into lower temperature reservoirs than flash plants, of between 74–199 °C. Rather than using steam directly, these plants pass the reservoir water through a heat exchanger that boils fluid in a closed-loop system containing a fluid with a low boiling point. Binary geothermal plants make up around 13% of global installed geothermal capacity. The US is currently the leading market in terms of current binary plants, followed by New Zealand.

Flash

Flash plants direct super-heated water or steam directly from the ground into tanks where water is flashed into steam using pressure differentials to drive turbines. Resource temperatures for these plants are typically over 200 °C. Flash plants are the most common type of geothermal and make up around 70% of total global installed geothermal capacity. Geographically the Philippines is the leading country in terms of installed capacity, followed by Mexico and Indonesia.

Table 10
Levelised cost of geothermal by region

Source: Bloomberg New Energy Finance
Note: *the given range is an average scenario and does not reflect actual maximum and minimum values

Technology	Geography	CAPEX (USDm/MW)	OPEX (USD/MW/yr)	Capacity factor (%)	LCOE (USD/MWh)
Flash	US	1.39–6.00	99,553–222,335	60–95	60–201
	Indonesia & Philippines	1.08–4.80	110,607–261,891	85–90	39–181
Binary	US	2.00–6.07	95,687–213,701	85–95	89–276

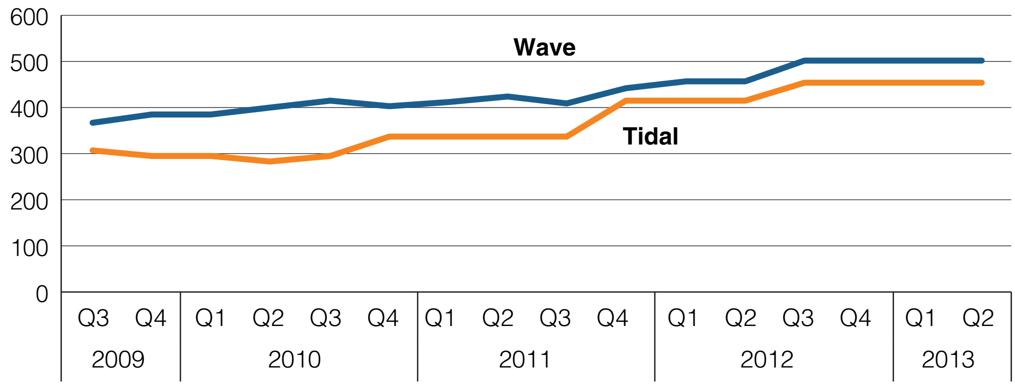
Marine

Marine power consists of four classes of technologies: wave, tidal stream, tidal barrage and ocean thermal energy conversion (OTEC) with numerous in-development subclasses. This report focuses on tidal stream and wave power technologies. There are approximately 12 companies leading the technology developers and steering their products towards commercialisation, but to date installations have consisted almost entirely of pilot phase projects and demonstrations with few exceptions. The companies active in the sector are targeting large scale commercial installations for 2013 onwards in a few highly concentrated areas such as the waters off Scotland, Australia and South Korea. Over the last few years the LCOEs of both types of electricity have increased as developers and manufactures have learned the true costs of the technology from demonstration projects at test sites in Europe and elsewhere. This technology class is the earliest stage class of all included in this report.

The UK Carbon Trust has produced a significant amount of research on these technologies as part of its Carbon Trust Marine Energy Accelerator program, which estimates that marine could eventually provide 20% of UK's electricity. On 27 June the UK announced a Contract for Difference Feed-in Tariff of GBP 305/MWh (USD450/MWh) for tidal and wave projects under 30MW, which the government hopes will help spur additional deployment. As a point of reference the same tariff for onshore wind is less than a third of that at GBP 100/MWh.

The UK is not alone in its government support for the sector; Australia, Japan and South Korea are also currently or planning to provide incentives via grants or technology development initiatives. In addition, China has a modest policy target of 50MW for marine by 2015. Due to the limited amount of deployment and the fact that these technologies are pre-commercialisation we have limited the scope to a global analysis.

Figure 11
Levelised cost of marine electricity over time, developed market average (USD/MWh)
Source: Bloomberg New Energy Finance



Tidal

The bulk of the world's existing tidal power capacity comes in the form of tidal barrage plants which are effectively small dams built to harvest energy from differences in water levels. These types of plants are unlikely to gain a significant foothold in the energy supply market due to high civil engineering costs not dissimilar from normal dams, as well as high environmental concerns. Tidal stream plants typically consist of either horizontal or vertical axis turbines that are fully or partially submerged and fixed to the sea floor, but they come in a wide arrange of designs. The global pipeline for tidal plant installations is over 5GW, but with under 10MW actually commissioned.

Cost estimates vary widely and the lack of commercial scale deployment makes it difficult to accurately assess the true costs of large scale installation and operation. Initial figures estimate that capital expenditure on USD/MW level can run anywhere from USD6.5m/MW to upwards of USD16m/MW. Figures from installed projects include a wide mix of pilot and small scale commercial development, so it is highly likely that as projects over 1MW in size become operational the upper bound of the range will drop.

Initial estimates for O&M costs, such as those from the UK Carbon Trust in 2006, underestimated O&M costs significantly, and true costs are only now becoming understood as the first major test projects spend longer periods of time in the water.

In relation to wave, tidal power projects are approximately a year ahead in terms of development and the field of underlying technologies is much narrower. The three main installed technologies are three-bladed turbines, two-bladed turbines, and single open-centre turbines.

Table 11
Levelised cost of tidal electricity by region
Source: Bloomberg New Energy Finance.
Note: *the given range is an average scenario and does not reflect actual maximum and minimum values

Geography	CAPEX (USDm/MW)	OPEX (USD/MW/yr)	Capacity factor (%)	LCOE (USD/MWh)
High cost	16.05	~130,000	25	1,049
Central	9.28	~130,000	35	451
Low cost	6.73	~130,000	45	263

Wave

Wave technologies vary more widely than tidal and have a significantly smaller development pipeline. Whereas there is over 5GW of in-development tidal globally there is under 2GW of wave. It is unlikely that commercial scale, multi-MW projects will roll out in significant numbers until at least 2016.

Wave units can be fully submerged, partially submerged and even above water onshore (to take advantage of onshore wave breaking). They can be anchored and fixed or floating, and no two units are similar. Major technology sub-classes include oscillating wave surge converters, attenuators, point absorbers and oscillating water columns.

Like tidal projects, the range of potential CAPEX varies significantly and is not particularly geographically specific at this point due to the early stage of deployment and lack of commercial scale installation.

Recently the wave industry has been in a tumultuous period marked by questions about the viability of many designs and punctuated by negative news such as the liquidation of well-known Irish firm Wavebob and major German utility E.ON's withdrawal from a project with Pelamis Wave Power.

Table 12
Levelised cost of wave electricity by region

Source: Bloomberg New Energy Finance.
Note: *the given range is an average scenario and does not reflect actual maximum and minimum values

Geography	CAPEX (USDm/MW)	OPEX (USD/MW/yr)	Capacity factor (%)	LCOE (USD/MWh)
High cost	16.05	~150,000	25	1,058
Central	8.78	~150,000	30	496
Low cost	5.48	~150,000	35	284

Hydro

For this report we split hydro into two categories: large dams over 10MW and small dams under 10MW, which includes run-of-river projects. The WEC Survey of Energy Resources published in 2013 indicates that there is a substantial potential for further development of small hydro and run-of-river capacity as well as for large hydro. While hydropower has already been exploited to a high degree in Europe (75%) and North America (69%), there still is significant potential in Latin America (33%), Asia (22%) and particularly in Africa (7%).

Due to the maturity and relative simplicity of the technology the economics can be very attractive if the right location can be found. Hydro power LCOEs are usually cost-competitive without financial support, especially for adequately sited large hydro, but the main barrier to development is the very high capital cost of building the installation. Other barriers to investment include low seasonal river flows and elevated levels of water use (which will have an effect on reservoir levels even in the case of large hydro), and resistance to flooding large areas of productive land.

Due to a huge variation in the capacity factors for hydro coupled with large differences in capital costs of main components such as cement and steel, there is a large range of potential LCOEs from these technologies across developed and developing countries. While average projects are able to compete directly with fossil fuels there remain many projects that are far more expensive.

Table 13
Levelised cost of hydro electricity globally

Source: Bloomberg New Energy Finance.
Note: *the given range is an average scenario and does not reflect actual maximum and minimum values

Geography	CAPEX (USDm/MW)	OPEX (USD/MW/yr)	Capacity factor (%)	LCOE (USD/MWh)
Small hydro	1.40–3.68	15,002–85,000	23–80	19–314
Large hydro	1.59–4.15	20,000–62,000	20–75	24–302

Coal, gas and nuclear

The economics of conventional thermal generation projects differ substantially from those of intermittent, low marginal cost renewables such as solar and wind. Regionally the largest differentiator between conventional coal and gas projects tends to be the cost of input fuels, which are highly localised. For nuclear projects upfront capital costs are high enough that fuel becomes less of a cost differentiator. The importance of fuel costs is shared by biomass facilities, but not by most other renewable types as once a renewable project is up and running the marginal cost of generation is minimal – typically only operations and maintenance.

Geopolitical changes have driven up the costs of new coal, gas and nuclear generation in developed countries and in some cases – such as the ban on new nuclear in Germany – there are limited options for the deployment of certain types of conventional power stations.

Coal

The likelihood of a significant amount of new coal generation coming online in Western Europe, the US and Australia is low. For the purposes of this report we have assumed a 10% cost of equity for our base hurdle rate, but indications are that the actual hurdle rates demanded by investors in order to induce them to supply capital to a new build coal plant may be on the order of 18% or higher, pushing the LCOEs up even further than below. In the case of both the Europe and Australia any new plant would be subject to an uncertain future carbon price, which is the main reason why investors consider these plant so risky. Despite this – in continental Europe, new coal plants continue to come online in Germany where the nuclear ban and other market-specific factors will likely drive new additions for the next few years.

Coal remains a growing generation source in Brazil and other parts of South America and in Southeast Asia, but China and India are the main markets for new coal development. In China, extremely low capital costs make China the cheapest country in which to generate power from coal. Coal plant capital costs hover around USD0.66m/MW, which is roughly 80% below the global average. When coupled with fuel costs using benchmark FOB[2] Newcastle coal (coal for export from the port of Newcastle, Australia), LCOEs for Chinese coal are as low as USD35/

2 FOB = free on board – term used in shipping to describe cases in which the seller is responsible for bringing the goods on board the ship, after which the responsibility is transferred to the buyer

MWh, less than half the estimated LCOE for a comparable new build plant in western Europe or the United States. These costs can be even lower when lower-cost locally mined coal is used, which is the case for coal plants close to mining centres such as Inner Mongolia.

Figure 12
Levelised cost of coal and gas fired electricity over time, developed market average (USD/MWh)

Source: Bloomberg New Energy Finance. CO_2 costs from BNEF's proprietary European Carbon Model CO_2 allowance forecast, applied to European plant costs.

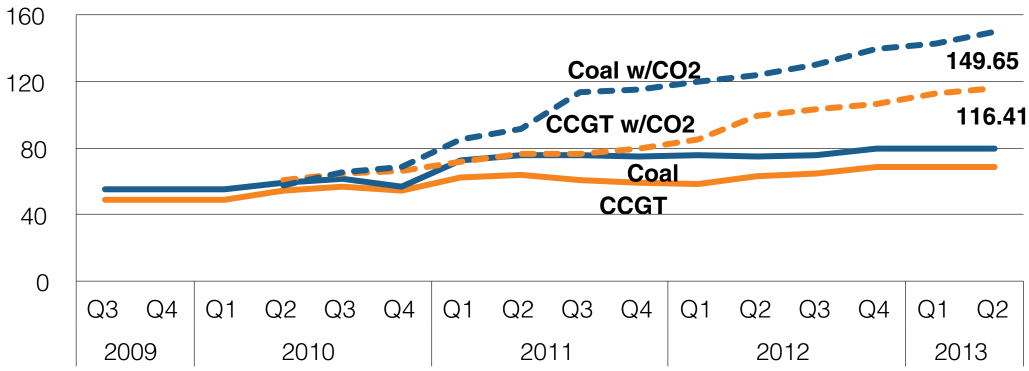


Figure 13
Levelised cost of coal electricity by region (USD/MWh)

Source: Bloomberg New Energy Finance

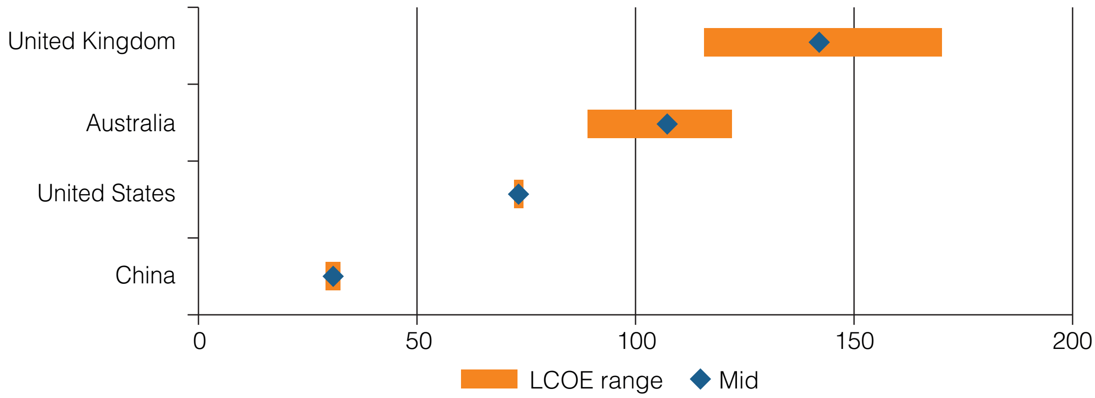


Table 14
Levelised cost of coal electricity by region

Source: Bloomberg New Energy Finance.
Note: *the given range is an average scenario and does not reflect actual maximum and minimum values

Geography	CAPEX (USDm/MW)	OPEX (USD/MW/yr)	Capacity factor (%)	LCOE (USD/MWh)
China*	0.66–0.66	32,820–50,000	80	35–39
Australia*	2.51–3.70	36,185–60,673	83	93–126
United States*	2.94–3.11	29,670–32,820	80–85	77–78
United Kingdom*	2.27–2.85	30,600–76,500	95–98	119–172

Gas

Combined-cycle gas turbines are much cheaper and easier to build than coal plants and are considerably cleaner. They are therefore more acceptable to local populations and if the economics are right, much more investable. The critical factor in the economics of CCGTs, and their viability, is the cost of gas. In the US – where the shale gas boom has pushed down natural gas prices to currently around USD3–4/MMBtu – the economics of CCGT plants look particularly attractive. In Europe and Asia however the picture is somewhat different. Europe relies extensively on oil–linked contracts with Russian suppliers and imported LNG at USD10–12/MMBtu, ie up to three times as high as US domestic prices. Although the carbon pricing mechanism in Europe helps gas relative to coal, current carbon prices are nowhere close to the levels to achieve parity. At the current high price of gas and low price of coal, carbon prices need to be over €40/tCO2 to equalize the cost of running gas and coal plants. Carbon prices are currently around €5/tCO2. In Asia, gas prices are even higher. Japan for example no indigenous resources and imports its gas through expensive LNG cargos which are typically priced at USD16–18/MMBtu, some four times US prices.

These price differentials significantly affect the cost of generating power from gas plants. In Europe even the most recently built CCGT plants are being mothballed due to the effects of high gas prices and competition from renewable and existing coal plants. In Japan the LCOE of new build CCGT is around USD150/MWh, while in the US it is between USD60 and USD70/MWh.

Figure 14
Levelised cost of CCGT electricity by region, USD/MWh

Source: Bloomberg New Energy Finance

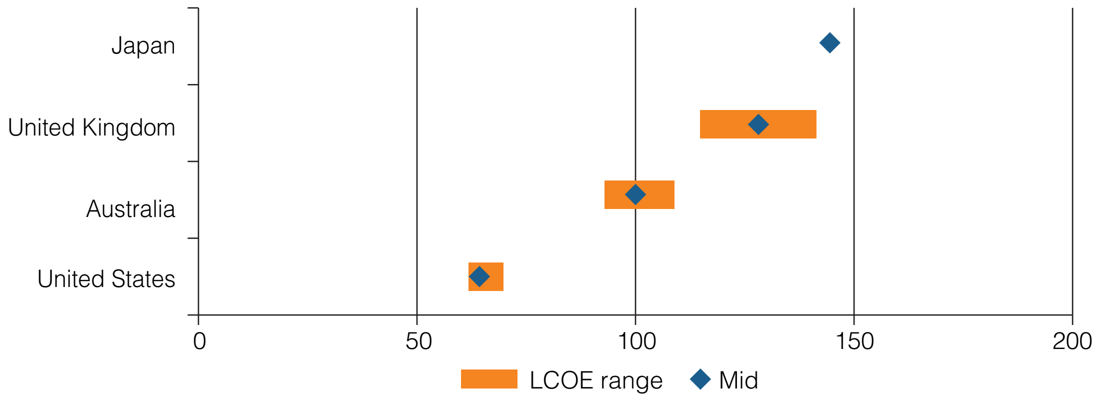


Table 15
Levelised cost of CCGT electricity by region

Source: Bloomberg New Energy Finance.
Note: *the given range is an average and does not reflect actual maximum and minimum values

Geography	CAPEX (USDm/MW)	OPEX (USD/MW/yr)	Capacity factor (%)	LCOE (USD/MWh)
United Kingdom*	0.76–0.90	23,182	80	114–141
United States*	0.97–1.00	14,620	60–80	61–69
Australia*	1.16	10,932	83	92–108
Global*	0.97	14,505	68	69
Japan*	1.51	58,000	78	148

Nuclear

Nuclear plant development is isolated to a small number of specific regions and countries: Russian and the CIS, China, India, South Korea and the UAE with small pockets of projects in South American, the US and Western Europe. Cost vary substantially, and due to the extremely high upfront capital required for a reactor the LCOE is determined primarily by CAPEX, impacted slightly by uranium prices.

On the high end globally are European Pressurized Reactors that are under construction in places like France and Finland, typing the scale at nearly USD7m/MW. On the low end are projects in the Middle East like Abu Dhabi's 5.6GW Barakah nuclear plant at an estimated cost of USD3.6m/MW and plants in China (EPRs and Barakah make up the high low scenarios respectively in Table 16). Little price discovery is available on many nuclear plants, and due to the very long planning and construction horizon relative to other generation options projects can be subject to significant cost overruns.

Table 16
Levelised cost of nuclear electricity by region

Source: Bloomberg New Energy Finance.
Note: *the given range is an average scenario and does not reflect actual maximum and minimum values

Geography	CAPEX (USDm/MW)	OPEX (USD/MW/yr)	Capacity factor (%)	LCOE (USD/MWh)
High cost	6.52	~122,880	92%	147
Central	4.80	~72,000	88%	94
Low cost	3.57	~56,000	85%	91

4

Conclusions

This report provides a unique worldwide reference source on the cost of both renewable and conventional power generating technologies, based on data from real projects. The LCOE analysis shows that the cost range across the renewable energy technologies is wide, considerably wider compared with conventional energies. The most mature and widely deployed clean energy technologies such as hydro and onshore wind are today close to reaching parity with traditional sources, while emerging technologies such as marine tidal and wave are still at the early phases of cost discovery.

For technologies that are widely deployed across the globe, such as onshore wind, crystalline silicon PV and hydropower, there are significant cost variations between the regions. The LCOEs in Western Europe, the US and most notably Japan are typically several times larger than those in China and India due to limited access to cheap components and higher O&M costs.

Many of the other technologies are currently only deployed in specific regions, depending on the characteristics of the technology and local policy support. However in line with the continued growth in clean energy investment, the geographic spread of the technologies is likely to increase in the future into countries such as Brazil, South Africa and South Korea.

As noted in the Introduction, the future of this project will depend on the WEC Member Committees and their affiliates providing the best data available, particularly for fossil fuel and nuclear technologies.

It is believed that the cost related information provided in this report will deliver powerful information for decision-makers in the energy sector and a true database for policy-makers. To enlarge the scope and power of further reports, your company is invited to join this brand new and unique WEC project.

Appendix

Methodology

Technology maturity

This report includes a study of all technologies that are beyond the pilot phase. Electricity generating technologies follow a similar path to other technologies: they follow a development curve that begins with pilot projects and leads to demonstration, commercialisation and full-commercial deployment. Wave and tidal technologies are the least mature of those studied in this report, and are currently being demonstrated at various test sites globally: the very first commercial projects have only been announced recently. Many of the renewable technologies in this report have reached commercialisation, but have yet to become cost competitive with more well established technologies gives a rough outline of the maturities of the various technologies that will eventually be covered by this report.

Use of empirical data

The calculation of LCOEs in this preliminary report is based on empirical data wherever possible. The data includes capital costs, operating costs, the cost of finance and load factors – either experienced or projected, and they are from actual projects that have been or are currently being built. Where actual project cost data is incomplete the analysis uses Bloomberg New Energy Finance's trend analysis on technology and financing costs.

The use of empirical data is valuable because it uses data from real projects. It can however produce LCOEs that may seem extremely high or unrealistic because subsidies government support mechanisms may have incentivised the construction of plants in otherwise unsuitable locations. Instances of this are most prevalent for onshore wind and PV projects where developers have built projects in what would normally be sites with uneconomically low resource availability that leads to low capacity factors, one of the key drivers of LCOEs.

Our central estimate for the most well developed markets for a given technology is a reflection of the most likely cost for a project, while in less developed markets the central estimate is an average of LCOEs for projects in that region.

Data sources

For regions where a technology's costs are widely understood and there are many relevant project examples, LCOEs are based on information from actual projects. This mainly applies to onshore wind and solar PV in the key geographies such as Western Europe, the US and China.

For those technologies which are less mature and have few examples of actual installations in the region from to calculate LCOEs, cost ranges are based on the disclosed project costs in order to reflect the actual LCOEs of operational projects in each region. As far as possible the analysis is based on data from projects where investment or purchase contracts have been completed. This universe of indicative costs is sourced from a database of projects provided by a combination of BNEF's proprietary clean energy project database and information provided by WEC network members.

For emerging technologies deployment is limited to a small number of projects or to certain specific regions. In these cases LCOE ranges may be difficult or impossible to accurately assess, but where possible we have attempted to determine reasonable estimates based on available data on resource assessments, observed O&M and capital expenditure costs for similar technologies or estimates provided by government or agency sources. Conversations with participants across the energy value chain, insight from BNEF sector analysts and data from reliable public sources also serve as important data sources.

Capital expenditure figures

When compiling CAPEX figures we break costs into three broad components: development, balance of plant and equipment.

Development costs are the most difficult component to assess due to differences in the cost and duration of application and permitting processes from country to country, but are also typically small when compared to those for the physical plant. Balance of plant (BoP) costs include non-core technology costs such as turbine tower foundations and on-site electrical for onshore wind. Equipment includes core-components such as turbines for CCGT plants. Equipment and BoP are combined and applied to expenditure in equal amounts over the construction period, but the use of two categories facilitates easier allocation of the drivers of plant costs.

Grid costs

Our CAPEX development is based only on on-site costs, excluding the cost of connecting a project to the grid. Whilst we recognise that for certain technologies such as offshore wind grid connection costs can represent a large share of final costs, this is a difficult component to include in the analysis. It is problematic to make assumptions about average distances to the grid and to analyse regional differences in who is responsible for the cost (in some countries the cost is borne by utilities or grid operators while in others by the developer). Costs also exclude the expense balancing costs and the cost of the externalities associated with additional renewable supply to the grid such as heightened flexibility requirements for conventional plants.

Inflation

Inflation rates are used to inflate O&M costs as well as the LCOE itself over the project's operational life. For each country the inflation rate used is the average of the IMF's consumer price index inflation forecast for each of the next five years.

Tax

Tax rates are sourced from the corporate income tax surveys of major global accountancy firms KPMG and Deloitte. Tax losses are not carried forward in the model.

Depreciation

Tax depreciation methods differ from country to country and eventually this study will aim to reflect the methodologies applied at the local level. However, this initial version assumes that capital expenditure is depreciated for 20 years using a straight line approach.

Currency

This study is done in USD. All local currency values have been translated to USD at current foreign exchange rates. The local currency-USD exchange rate can have a significant effect on USD LCOEs.

Labour and materials

Where local O&M figures are available we use the O&M rates as revealed. However, where benchmark O&M costs are not available we calculate the cost of labour and materials of O&M separately. The cost of labour is adjusted from projects where data are available using purchasing power parity (PPP). The cost of materials uses average discounts observable in total plant capital expenditures.

Debt

For technologies that are bankable in a given region we apply appropriate debt/equity ratios, spreads and tenors for the operational term loans and where applicable construction and development loans. Debt repayment schedules are developed using a simple mortgage style approach with equal repayment values over the tenor of the operational loan. All projects are priced over the USD swap rate for the tenor period to reflect that end borrowing costs would include the cost of locking in a fixed borrowing rate using a USD floating to fixed rate swap contract.

Equity

The complexities of assessing the returns required by local equity investors are beyond the scope of this report. As a way of simplifying the process of valuing projects regardless of local risks and technology-specific risks we assume that all equity investors require a 10% return on their investments.

Example calculation

We define the LCOE as the USD/MWh price for an inflation-adjusted, fixed-price off-take agreement that, taking into account all project-specific costs, offers the sponsor and/or project developer the minimum equity return necessary to undertake the project.

An LCOE of USD100/MWh for a wind farm indicates that after factoring in cost of development time and cost, construction, turbine costs, balance of plant, short and long-term financing and operating costs, signing a power purchase agreement at USD100/MWh would return the owner of the project exactly their 'hurdle rate' or the minimum expected equity return required to give the project a green light. Unless otherwise specified we target a 10% equity IRR as a hurdle rate for all technologies, to represent the perspective of a "technology agnostic" developer.

CAPEX costs are obtained by leveraging BNEF's proprietary dataset of project financings coupled with our proprietary indexes. Below is an example of how we calculate the bottom up cost of a PV plant on a per watt basis.

These values are input into our financial model, which scales the costs to account for the full charge of a 50MW plant, plus assumed development costs, and allocates the costs during construction and development accordingly. Charges are allocated to the equity portion of the financing first, which in this case accounts for 30%, and then withdrawals are made on the construction loan, which accounts for 70%. Interest is accrued during the construction period. Our default method for assigning annual term loan repayments is a mortgage method, whereby the loan is repaid in equal installments annually over the term of the loan, which in this case is 10 years.

Annual generation is calculated by applying a load factor (developed based off of average local resource availability plus technical efficiency of the panels) multiplied by technical availability and an annual degradation factor. From this figure we determine the annual operational hours, and subsequently the variable operating costs, which are added to fixed OPEX to arrive at total OPEX.

Deprecation and tax assumptions are layered in, and interest charges from the term loan are deducted to arrive at a final net operating profit, which in this case is the amount of cash available for distribution to the project's equity holders.

The LCOE itself is calculated as the annual hourly electricity price required to make the IRR of the equity payments (the NOPLAT line above) equal to the target rate, which in this case is 10%. Our model solves for the year 0 value that makes this equation balance. The LCOEs are inflated over time at a specified rate, 2% in this case.

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