1 GLOBAL RENEWABLE POWER MARKET TRENDS

Introduction

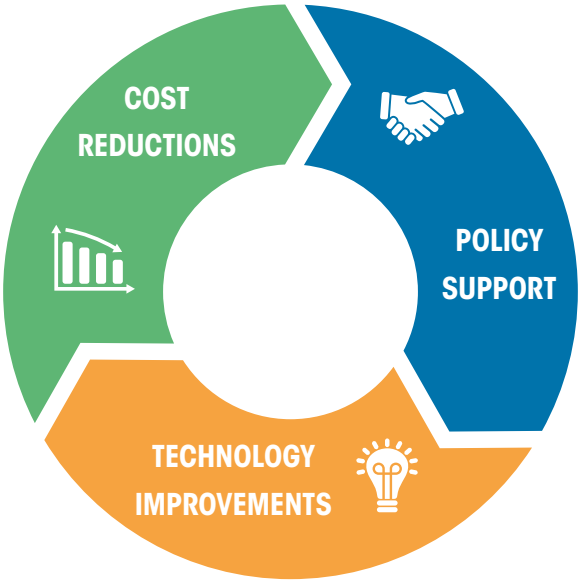
Renewable energy technologies can help countries meet their policy goals for secure, reliable and affordable energy, electricity access for all, reduced price volatility and the promotion of social and economic development. What is not widely appreciated is that with recent cost reductions, renewable power generation technologies can achieve these at a lower cost than alternatives.

The reality is that today we are witnessing the beginning of what will one day be the complete transformation of the energy sector by renewable energy technologies. This transformation is being driven by a virtuous cycle of long-term support policies accelerating the deployment of renewables, which leads to technology improvements and cost reductions (Figure 1.1). This increased deployment increases the scale and competiveness of the markets for renewable technologies, and with every doubling in cumulative capacity of a renewable technology, costs can come down by as much as 18% to 22% for solar PV and 10% for wind.[3] The result is striking: renewable energy technology equipment costs are falling and the technologies themselves are becoming more efficient. The combination of these two factors is leading to declines, sometimes rapid ones, in the cost of energy from renewable technologies.

To date, this transformation is most visible in the power generation sector, where dramatic cost reductions for solar photovoltaic (PV), but also, to a lesser extent, for wind power are driving high levels of investment in renewables. At the same time, where untapped economic hydropower, geothermal and biomass resources exist, these technologies can still provide the lowest-cost electricity of any source.

[3] This is often measured by "learning rates", a percentage reduction in costs for every doubling of cumulative installed capacity. These learning rates are high for renewables, as although they are commercially mature, they still have significant cost reduction potential unlike fossil fuels and nuclear.

Figure 1.1: Renewables are experiencing a virtuous cycle of cost reductions



This report summarises historical trends in the cost and performance of renewable power generation technologies (biomass for power generation, concentrating solar power, hydropower, solar photovoltaics and wind) and details information on the latest cost estimates available for 2014. This report is the eighth report on the costs and performance of renewable and draws heavily on the data in IRENA's world-class resource, the IRENA Renewable Cost Database. This database contains project data on the cost and performance of over 9 000 utility-scale[4] renewable energy projects and over 750 000 small-scale solar PV projects. The analysis is supported by earlier IRENA work, which analysed in more detail some of the technology and performance characteristics of renewable power generation technologies that underpin the economics of renewable power generation.[5]

[4] The database also includes partial data for around 6 000 other renewable power generation projects. For most of these projects the capacity factor is typically missing, although sometimes it is the total investment costs, and so the levelised cost of electricity cannot be accurately calculated.

*[5] See the IRENA **Renewable Energy Technologies: Costs Analysis Series**, Volumes 1 to 5 (IRENA, 2012a-e).*

In the past, deployment of renewables was hampered by a number of barriers, including their high up-front costs. Today's renewable power generation technologies are increasingly cost-competitive and are now the most economical option for any electricity system reliant on oil products (*e.g.* some countries and for off-grid electrification); in locations with good resources, they are the best option for centralised grid supply and extension. However, the public debate around renewable energy continues to suffer from an outdated perception that renewable energy is not competitive.

The aims of this report are to:

- Provide up-to-date, verified data on the range of costs and performance of renewable power generation technologies by country and region;
- Highlight the increasing competiveness of renewables and the fact that with a level playing field, renewables are now often the most economical choice for new capacity;
- Present clearly the business case for renewables, based on real-world project costs;
- Ensure that decision makers in government and the energy industry have the latest, fact-based data to support their decisions; and
- Provide powerful communications messages about the continued declining costs of renewables and their increasing competitiveness.

By reducing uncertainty about the true costs of renewable power generation technologies, governments can be more ambitious and efficient in their policy support for renewables. Better information about cost reductions are also an important component in communicating that the support policies for renewables are working and deployment is driving down costs.

This is particularly important, because although renewable power generation technologies now account for around half of all new power generation capacity additions worldwide (IRENA, 2014a), deployment is still too slow to achieve the ambitious goals that countries have set for a sustainable energy future that will prevent dangerous and costly climate change.

The following sections of this paper outline the principle findings of the six renewable power generation technologies analysed in this report – wind power, solar PV, concentrating solar power (CSP), hydropower, biomass for power and geothermal – and highlight the key insights for policy-makers.

Rationale for IRENA's cost analysis

The real costs of a project are one of the foundations investment decisions stands on and are critical to understanding the competitiveness of renewable energy. Without access to accurate, comparable, reliable and up-to-date information on the actual project costs and performance of renewable energy technologies, it is difficult, if not impossible, for governments to arrive at an accurate assessment of which renewable energy technologies are the most appropriate for their circumstances. IRENA's cost analysis programme is a response to a call from Member States for better and more objective cost data. Providing this information, with an accompanying analysis, will help governments, policy-makers, investors and utilities make informed decisions about the role renewables can play in their energy sector.

The rapid growth in installed capacity of renewable energy technologies and the associated cost reductions mean that data from even one or two years ago can significantly overestimate the cost of electricity from renewable energy technologies. In the case of solar PV, even data six months old can significantly overstate costs in some markets.

Therefore, there is a significant amount of perceived knowledge about the cost and performance of renewable power generation that is not accurate and can even be misleading. At the same time, a lack of transparency in the methodology and assumptions used by many to make cost calculations can lead to confusion about the comparability of data. By analysing a global dataset, this report provides one of the most comprehensive overviews of renewable power generation costs using a consistent methodology and set of assumptions.

IRENA plans to collect renewable energy project cost data for all sectors, although the work has commenced with the power generation sector (IRENA, 2012a-e; IRENA, 2013a) and the transport sector (IRENA, 2013b). Work on stationary applications, air and sea transport will be started in 2015. The data and analysis in these publications are designed to assist countries with their renewable energy policy development and planning. The analysis includes projections of future cost reductions and performance improvements so that governments can incorporate likely future developments into their policy decisions. This work is ongoing and further efforts are required to overcome significant challenges in data collection, verification and analysis. The underlying analysis and data collected on the costs and performance of renewable energy technologies and fuels can also support more detailed, policy-relevant products that provide decision makers with information about ongoing cost trends or future cost reduction potentials. As an example, IRENA is developing the IRENA PV Parity Indicators to help policy-makers track the evolution of solar PV competitiveness. The IRENA Renewable Cost Database can also support important analyses that update out-of-date analyses that policy-makers, industry and energy and climate sector modellers rely heavily on.

As an example, IRENA is in the process of undertaking a comprehensive update of the learning curve analysis for wind across 11 countries that account for 85% of cumulative installed wind capacity. This analysis will update the learning rate for wind (existing estimates are not comprehensive or only use data up to around 2006, two to three years before wind turbine price peaks) and extend it for the first time to the levelised cost of electricity and decompose the drivers for the evolution between capital costs, technology improvements, wind resource quality and changes in operations and maintenance (O&M) costs.

Different cost metrics

It is important to note that the cost of power generation technologies can be measured in a number of ways, and each way of accounting for the cost brings its own insights. The analysis summarised in this paper represents a static analysis of costs. The optimal role of each renewable technology in a country's energy mix requires a dynamic modelling of electricity system costs to take into account the many complexities of operating an electricity grid (this is discussed in more detail in Chapter 2).

This report compares the cost and performance of renewable power generation technologies, and the data across technologies, countries and regions. It takes a range of simple metrics analysed using a consistent boundary in order to ensure robust analysis, comparability of the data and the possibility of conveying simple messages (see Annex for a discussion of the approach). The analysis focuses on equipment costs, total installed cost and the levelised cost of electricity (LCOE) of renewable power generation options, given a number of key assumptions.

The LCOE analysis requires a significant amount of additional data or assumptions, such as economic life, cost of capital, efficiency, technology impacts and O&M. Where project-specific data are available (*e.g.* for capacity factors, which are often driven by a mix of technology, renewable resources and economic factors), these are presented in the appropriate chapters. Table 1.1 presents the range of assumptions that are required to calculate the LCOE of different renewable power generation technologies for which project-specific data are not discussed in the appropriate chapters.

The assumptions used are relatively conservative when considering the technical lives of many of these technologies, but reflect the economic realities that investors' scarce capital requires significantly shorter payback periods, as well as the times between major costly refurbishments and upgrades that are not covered in O&M costs.

The weighted average cost of capital

The analysis in this report assumes a weighted average cost of capital (WACC) for a project of 7.5% (real) in Organisation for Economic Co-operation and Development (OECD) countries and China, where borrowing costs are relatively low and stable

Table 1.1: Assumptions for the calculation of the levelised cost of electricity not derived from project data

	Economic life	Weighted average cost of capital, real	
		OECD and China	Rest of the world
Wind power	25	7.5%	10%
Solar PV	25		
CSP	25		
Hydropower	30		
Biomass for power	20		
Geothermal	25		

regulatory and economic policies tend to reduce the perceived risk of renewable energy projects, and 10% in the rest of the world.[6] These assumptions are average values, but the reality is that the cost of debt and the required return on equity, as well as the ratio of debt-to-equity, varies between individual projects and countries depending on a wide range of factors. This can have a significant impact on the average cost of capital and the LCOE of renewable power projects. It also highlights an important policy issue: in an era of low equipment costs for renewables, ensuring that policy and regulatory settings minimise perceived risks for renewable power generation projects can be a very efficient way to reduce the LCOE by lowering the WACC.

The key factor that determines the cost of capital is risk. A project with greater risk (*e.g.* of non-payment of electricity sales, currency risk, inflation risk or country risk) will require a higher rate of return. Capital can come in the form of equity and loans, while the project may be structured in a variety of ways. Equity is more expensive than secured loans, all else being equal, because it carries more risk in the eventuality that the project underperforms or goes bankrupt.

The key benchmark for assessing the relative cost of risk is the "market risk premium", which is the difference between the average market expected rate of return and the risk-free rate (*e.g.* government bonds). The energy sector is often less risky than the market as a whole, and therefore may have a lower risk premium than the market average, but the inverse is also possible, depending on the market. Researchers have compiled a set of estimated market risk premiums for 51 countries by surveying finance professionals in the respective countries. The average estimated market risk premium for 28 out of 34 OECD countries was at 6.07% (Fernandez et al., 2011).

The cost of capital for renewable projects is affected by the nature of the market, government policy, technological maturity and capacity factors. Policy risk is scrutinised by investors and can render computations of risk investments highly variable (Oxera, 2011).

Governments and private sector companies can develop projects. Governments can generally borrow at a lower rate because the risk is generally, but not always, considered to be lower. However, projects developed by governments tend to be more expensive than commercial projects, whose cost pressures are more intense,[7] which can negate the benefit of lower capital costs. An additional complication is that small projects from private investors or communities may have trouble finding finance and, if they do, generally pay higher fees than large established companies developing large-scale projects.

Countries with lower perceived political and country risk, a proven track record and respected institutions benefit from more generous terms

[6] *All references to discount rates, interest rates, return on equity and the WACC in this report are real unless otherwise indicated.*

[7] *This is not always the case, as private utilities with a monopoly or in a market with little competition may also have little incentive to minimise costs.*

Table 1.2: Categorisation of energy sector project risk factors

Phase	Pre-construction	Constuction	Operation	Country risk
Risks	• Technology risk • Project design • Debt and equity financing	• Constuction delays • Cost overruns • Environmental mitigation plans • Social mitigation plans	• Operation and maintenance plans • Output quality/ volume • Resource fluctuations • Electricity sales payments (PPA contracts, etc.)	• Currency devaluation • Currency convertibility/ transfer • Political force majeure • Environmental force majeure • Regulatory risk

and are more likely to be able to attract private investors and arrange commercial loans. Efforts to minimise the sources of risk (Table 1.2), wherever possible, will help to reduce the cost of capital and improve the project economics.

The financial structure of renewable generation projects and the cost of capital vary widely by technology, country, project developer and region. As an example, in the United States, between the fourth quarter of 2009 and the fourth quarter of 2010 the quarterly average required return on equity for wind projects ranged from a low of 9% to a high of 15%; while over the same period, the quarterly average cost of debt for wind projects ranged from a low of 4.9% to a high of 11% (REFTI, 2011). Making the simple assumption that the debt-to-equity ratio is between 50% and 80%, and that debt maturity matches project length, results in project discount rates of between 5.8% and 11% for wind projects. This has a dramatic impact on the LCOE of wind projects, as the LCOE of wind with a capital cost of 11% will be 45% higher than one with a cost of 5.8%, assuming a 35% capacity factor and USD 0.015/kWh for O&M.

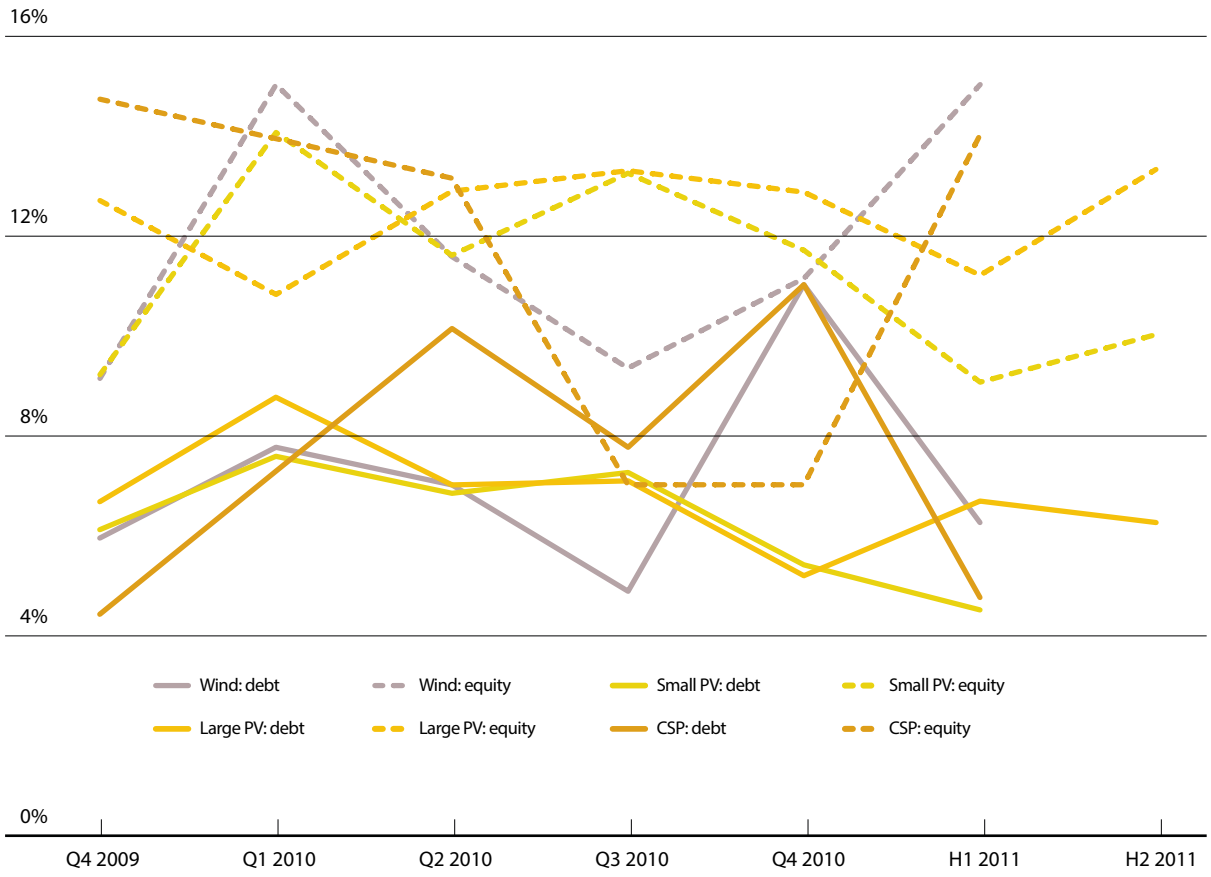
The data for the projects examined in the United States between the fourth quarter of 2009 and the second half of 2011 are presented in Figure 1.2. The volatility of the data suggests that project-specific factors and the nature and experience of project developers have a significant impact on financing costs and return on equity expectations. This suggests that very comprehensive data sets will be required to gain a clear understanding of the underlying contribution of different risk factors to financing costs.

It is illuminating to note that from 2009 to 2011, for the projects that were part of the analysis, just 12% of projects identified project economics as the largest barrier to the project and 7% stated there was no large barrier to their project (REFTI, 2012). However, 13% of projects cited the difficulty of raising capital as the largest barrier, along with 12% that identified finding a tax equity investor. A further 12% cited the power purchase agreement (PPA) or creditworthiness of the off-taker as the largest barrier.[8]

The situation can be very different in developing countries, as various risks can often make it difficult for project developers to mobilise the funds necessary to bring a project to fruition, or if they can, the financing costs mean the economics of the project will not be sufficient to provide an adequate return on equity. In these cases, multi-lateral and bi-lateral lending can be critical to unlocking commercial funding and terms that are not so onerous that they undermine the project economics. For instance, a reasonable weighted average cost of capital for African projects is 15-20%, except where strong guarantees are in place. This is significantly higher than the average cost of capital for renewable energy projects in OECD countries, typically between 6% and 12%. Bringing down these costs will dramatically

[8] *Note that the single largest barrier identified by 16% (or 80 projects) wasn't listed among the nine options given, but fell under "other", suggesting that project financing faces a wide range of challenges.*

Figure 1.2: Debt and equity costs for wind, solar PV and CSP in the United States, 2009 to 2011



Source: Renewable Energy Finance Tracking Initiative

improve the economics of renewable power generation projects in Africa.

Public sector involvement (government, multi-lateral or bi-lateral lenders) and guarantees can help to reduce risks that the developer has little or no control over and encourage the private sector to invest based on the project's technical and economic merits. As a result, interest in public-private partnerships (PPPs) has been growing, with efforts to develop appropriate public policies and regulatory frameworks that will leverage multi-lateral and bi-lateral lending to increase private sector investments in renewables and climate finance in general. As commercial lenders gain experience in funding renewable energy projects in robust regulatory and economic frameworks, then access to finance and the terms offered should improve. This would have a very important impact on the deployment of renewables in developing countries where there is huge untapped potential waiting to be unlocked to meet the growing demand for electricity.

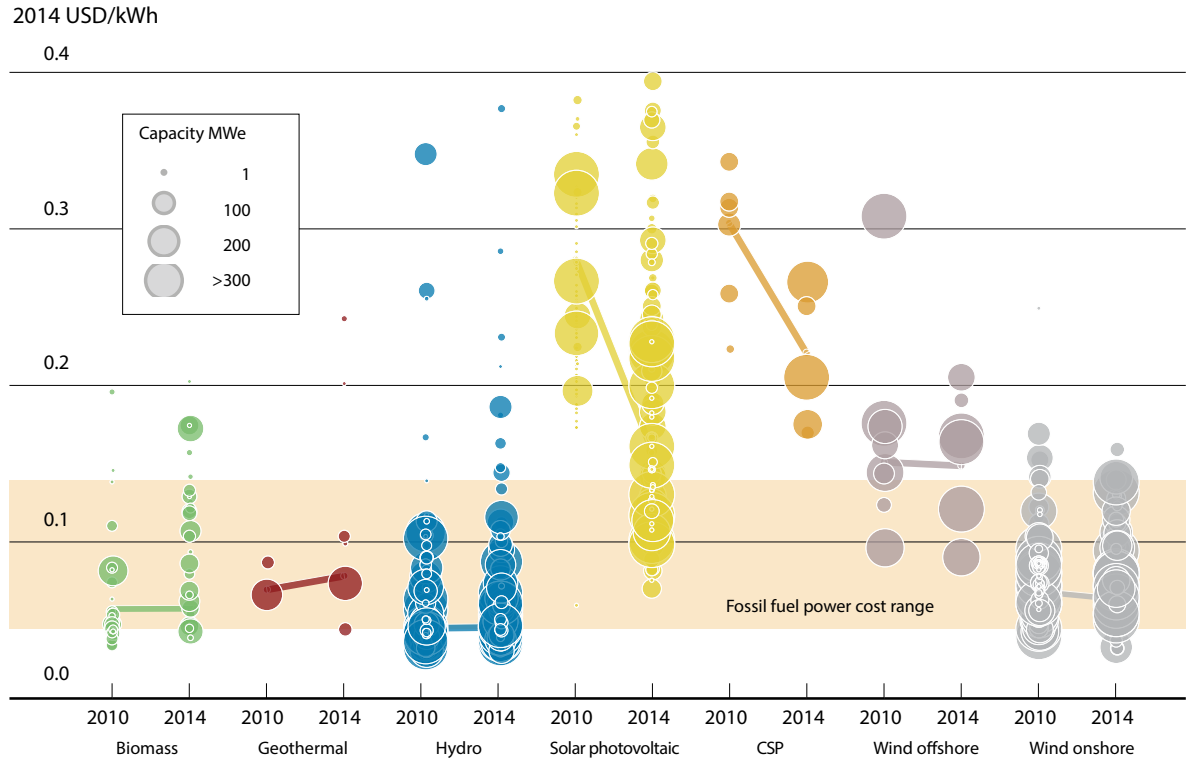
2 RENEWABLE POWER GENERATION COSTS IN 2014

Introduction

The relentless decline in the costs of a range of renewable power generation technologies continued in 2013 and 2014. The competitiveness of renewable power generation technologies has reached historic levels; onshore wind power, solar photovoltaic (PV) and concentrating solar power (CSP) installed costs have continued to fall as their performance has improved, significantly lowering the cost of electricity from these sources. At the same time, biomass for power, geothermal power and hydropower are all mature technologies that, where unexploited economic resources exist, can provide the lowest cost electricity of any source. Renewable power generation technologies are now competing head-to-head with fossil fuel-fired electricity generation options (Figure 2.1).

Solar PV module prices in 2014 were 75% lower than their levels at the end of 2009, while the total installed costs of utility-scale PV systems have fallen by between 29% and 65% between 2010 and 2014 depending on the region. Figure 2.1 presents the evolution of the LCOE of renewable power generation technologies between 2010 and 2014 where the size of the circle is the project size and the centre of the circle represents the LCOE on the Y axis. The levelised cost of electricity (LCOE) of utility-scale solar PV projects has fallen as low as USD 0.08/kWh in 2014 (Figure 2.1). Where good resources exist and low-cost financing is available, utility-scale PV projects are now being built that provide electricity at a lower cost than fossil fuels (*e.g.* in Dubai, Chile and a range of other countries) without any financial support,

Figure 2.1: The levelised cost of electricity from utility-scale renewable technologies, 2010 and 2014



Source: IRENA Renewable Cost Database.

Note: Size of the diameter of the circle represents the size of the project. The centre of each circle is the value for the cost of each project on the Y axis. Real weighted average cost of capital is 7.5% in OECD countries and China; 10% in the rest of the world.

even where indigenous fossil fuels are abundant. A similar story is unfolding in the residential solar PV sector, as the LCOE of solar PV has fallen by between 42% and 64% between the beginning of 2008 and 2014.

Onshore wind is now one of the most competitive sources of electricity available as continued technology improvements have increased capacity factors at the same time as installed costs have been declining. As a result, the LCOE of wind is now typically in the same cost range, or lower, than that of fossil fuel power generation. As an example, the best wind projects in the United States are delivering electricity for USD 0.05/kWh without financial support.

Although the story is nuanced, given the LCOE range for renewable projects, it is clear that on average the mature, commercially available renewable power generation technologies have costs similar to or less than fossil fuels in many regions as costs have fallen and technologies improved. With continued cost reductions in the future there will be a growing wedge opening between renewables and their more expensive fossil fuel options for power generation.

The increased competitiveness of renewables will require policy-makers to shift their emphasis from individual technology support to a system-wide approach to facilitate the transition to a sustainable electricity sector. This shift will be vital due to increasing power system level integration issues which will require advance planning as economies head towards 30% or more of variable renewables. The shift in policy focus will require broader policy changes that also adapt the market structure and align stakeholder incentives to minimise overall system costs, yet still support renewables in an equitable fashion while the externalities and risks of fossil fuels and nuclear power are still not realistically priced. As the share of variable renewables grows, the importance of the more mature renewable power generation technologies (*e.g.* biomass for power, geothermal and hydropower) as well as CSP with thermal energy storage may grow and their ability to provide ancillary grid services and shift generation through time will become highly valuable for minimising overall system costs.

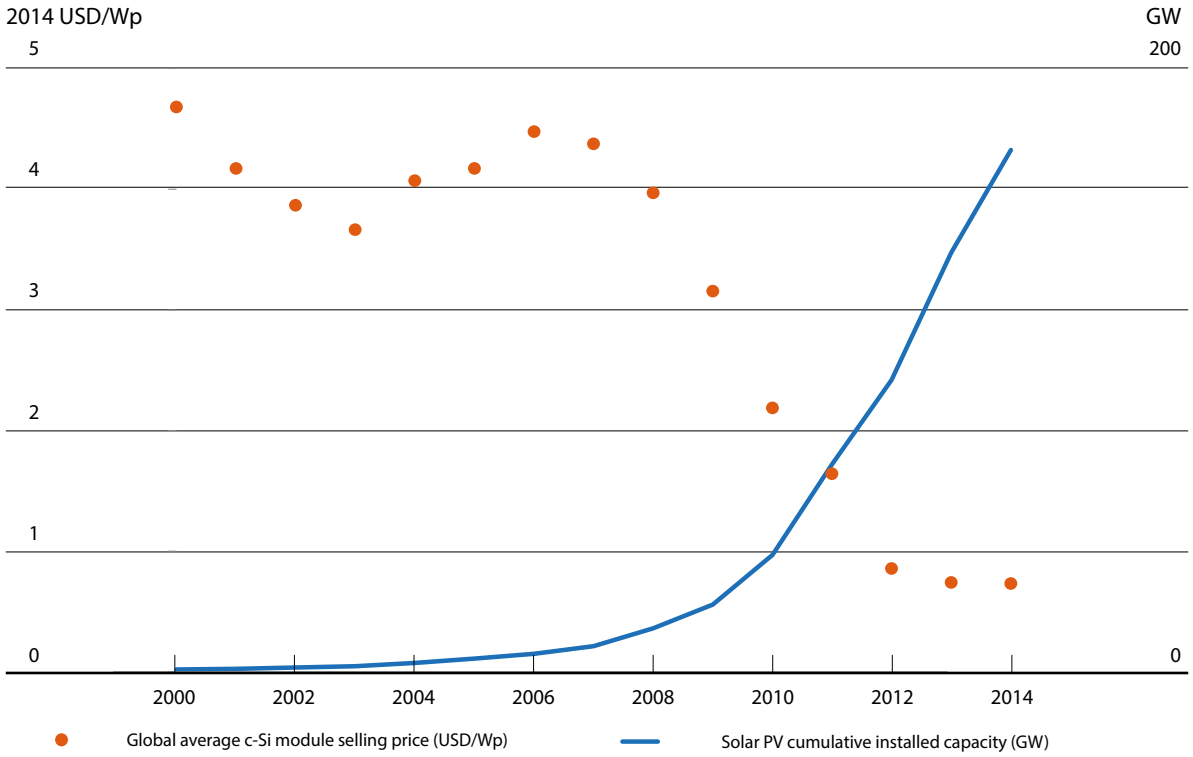
With utility-scale renewable power generation options now competitive in a growing number of markets, renewables have never been more competitive. However, much remains to be done to ensure that decision makers are aware of just how competitive renewables are. A wide disparity still exists between the most competitive renewable electricity generation projects for a given technology and the most expensive. This is also true of the ranges between countries and regions. Part of this variation is due to differences in renewable resource quality between different locations. It is also due to the wide variation in total installed costs for projects, and for a number of reasons.

One factor is site-specific issues, which can have an important impact on overall project development costs (*e.g.* quality and availability of local infrastructure, distance of the project from existing transmission lines, etc.). Differences in installed costs also arise because markets for individual technologies in different countries, and even within regions of a country, can be at very different stages of maturity.

As a result, cost structures can vary quite significantly, but typically decline as small under-developed markets grow and gain a core of experienced project developers and supporting contractors who can work together to lower project development costs as the market grows to "local" maturity.

Despite the theoretical understanding of the impact of these factors on cost variations, there are also examples of wide cost variations within an individual, relatively mature market (*e.g.* small-scale residential PV systems in California). With the declines in equipment costs in recent years and the growing importance of balance of system costs (BoS) as a large source of future cost reductions, much more research needs to be done in this area. A better understanding of why cost differentials exist may provide policy-makers with indications about what relatively simple regulatory or institutional changes could significantly reduce average costs by shifting system costs to the lower end of today's ranges.

Figure 2.2: Cumulative global solar photovoltaic deployment and solar photovoltaic module prices, 2000 to 2014



Sources: IRENA and pvXchange, 2014.

Renewable power generation costs, policy support and deployment

The energy sector is currently undergoing a transformation that represents the beginning of the transition to the renewables-dominated, truly sustainable power sector required to avoid the dangerous effects of climate change. The transformation of the energy sector is most evident in the power sector, where renewables are now estimated to have added around half or more of global new capacity required every year from 2010 on. Renewable energy capacity additions have risen six-fold between 2001 and 2013, to reach around 120 GW, with over 100 GW added every year between 2011 and 2013.

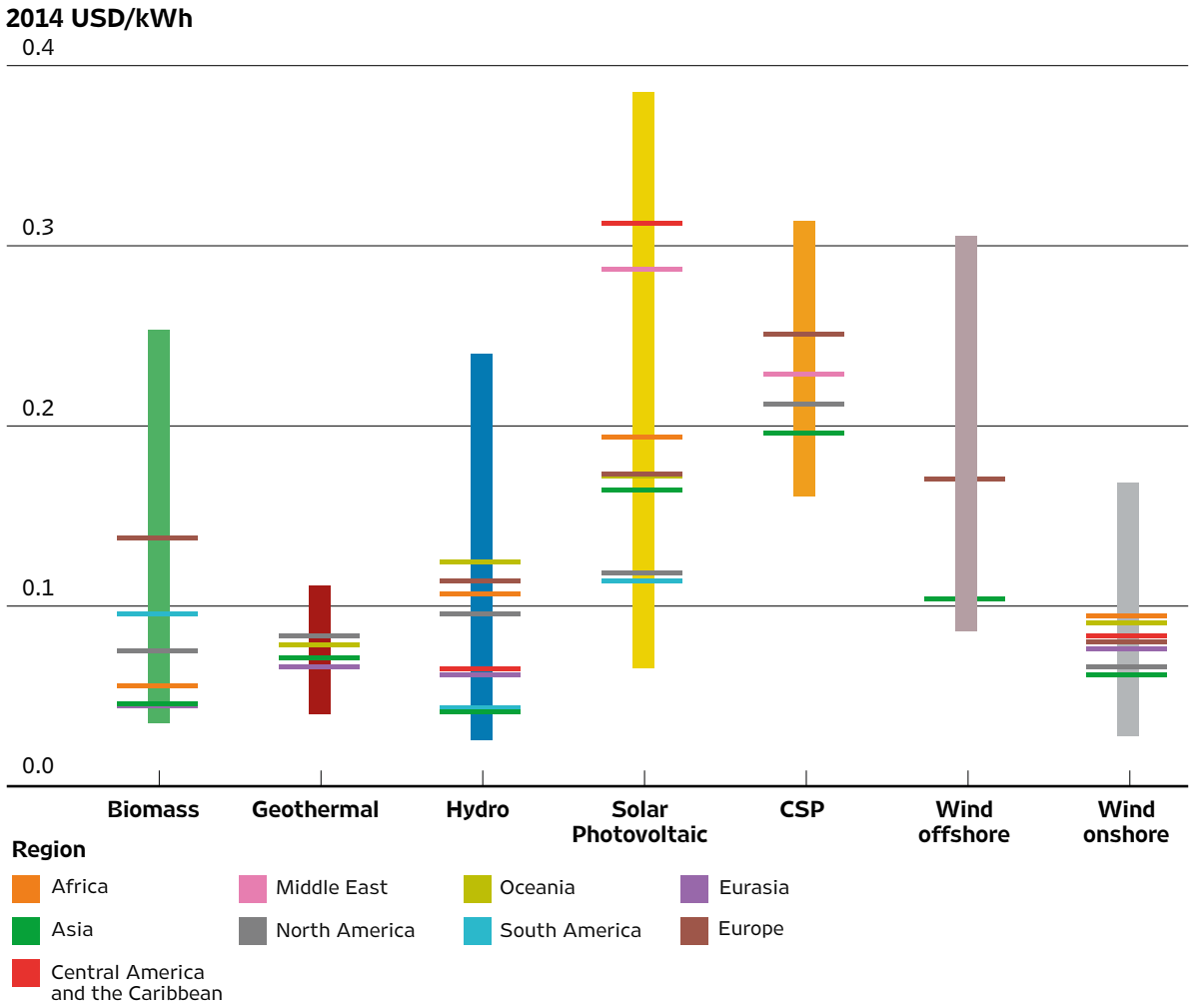
This is an active transformation; the policy support for renewables to meet countries' long-term goals for secure, reliable, environmentally friendly and affordable energy is bearing fruit. Learning investments have been made that have driven down the LCOE of renewable technologies, as a virtuous cycle of high levels of new capacity additions has unlocked technology improvements and driven down installed costs at the same time.

The sometimes rapid declines in the LCOE of renewable power generation technologies are possible because, although most renewable power generation technologies are mature, commercially proven products, they are not yet mature from a cost perspective. Thus, unlike fossil fuel and nuclear technologies, where installed costs are at best stable and often rising due to increasing environmental or safety performance requirements, renewable technologies have significant or even very high learning rates.[9]

Solar PV modules, for instance, have learning rates of between 18% and 22%, and the growth in cumulative installed capacity of solar PV relative to PV module cost declines is striking (Figure 2.2). It is notable that at the end of 2000 cumulative installed capacity was less than 1 GW globally. At the end of 2014, cumulative installed capacity has likely exceeded 180 GW with strong growth likely in 2015.

[9] *Learning rate refers to the fixed percentage reduction in equipment or installed costs for each doubling of cumulative installed capacity. The concept can also be applied to trends in LCOE, but there is significantly less research on this topic.*

FIGURE 2.3: TYPICAL LEVELISED COST OF ELECTRICITY RANGES AND REGIONAL WEIGHTED AVERAGES BY TECHNOLOGY, 2013/2014



Source: IRENA Renewable Cost Database.

RENEWABLE POWER GENERATION COSTS BY TECHNOLOGY

The typical LCOE range and regional weighted averages of today's renewable power generation technologies are highlighted in Figure 2.3. Given today's installed costs, the performance of renewable power generation technologies and current prices for fossil fuels and conventional technologies, renewable technologies are now the most economic solution for off-grid electrification and for new centralised grid supply in locations with good resources.

The high costs of small-scale diesel-fired electricity generation are made even higher in very remote locations where poor, or even non-existent, infrastructure can mean that transport costs increase the cost of diesel by 10% to 100% compared with the prices in cities. The recent decline in the LCOE of renewable power generation technologies represents a historic development, as it means that renewable technologies should provide the first introduction to modern energy services for 1.3 billion people currently without access to electricity on economic grounds.

It is not just off-grid that electricity systems remain dependent on diesel-fired generation. The falling cost of renewables means that virtually any electricity system based predominantly on oil-fired generation – such as on islands and in many countries – will see system generation costs fall by integrating renewables.

Reinforcing the earlier IRENA analysis of the LCOE of renewable power generation technologies (IRENA, 2013), it is apparent that the regional weighted averages for the LCOE of the projects

in the IRENA Renewable Cost Database for many technologies now typically fall within the same cost range as for fossil fuel-fired electricity. What is remarkable is that the rapid declines in solar PV module prices and installed costs now mean an increasing number of solar PV projects are economic at the utility-scale without subsidies.

The average LCOE of utility-scale solar PV has fallen by around half in the four years between 2010 and 2014, as solar PV module prices have declined by two-thirds to three-quarters in that time. The weighted average LCOE by region for utility-scale solar PV projects that were installed in 2013 and 2014 ranged from a low of between USD 0.11 and USD 0.12/kWh in South and North America to over USD 0.30/kWh in Central America and the Caribbean. Projects are now being built with an LCOE of USD 0.08/kWh, while even lower values are possible where low-cost financing is available. For example, a recent tender in Dubai saw a successful bid for a purchase power agreement (PPA) without financial support of just USD 0.06/kWh.

The average LCOE of residential solar PV systems was estimated to be between USD 0.38 and USD 0.68/kWh in 2008. This declined to between USD 0.14 and USD 0.46/kWh in 2014. The LCOE for residential systems declined by 40% to 66% between 2008 and 2014.

Hydropower produces some of the lowest-cost electricity of any generation technology. The LCOE of large-scale hydro projects at excellent sites can be as low as USD 0.02/kWh, while average costs are around USD 0.05/kWh where untapped economic resources remain. Small-scale hydropower can also be very economic, although typically it has higher costs and is sometimes more suitable as an option for electrification that can provide low-cost electricity to remote communities or for the local grid.

There is a clear cost dichotomy for hydropower between regions with remaining economic resources to exploit and those where most of the economic resources have been exploited already. Asia, Africa and South America all experience LCOEs for hydropower projects of on average USD 0.04 to USD 0.05/kWh. In contrast, in regions which have exploited their most economic resources, weighted average LCOE ranges are around USD 0.09 to USD 0.10/kWh (*e.g.* in Europe, Eurasia, North America and Oceania). In addition to the higher costs, these regions are also constrained in the amount of economic capacity that still remains to be added.

Onshore wind now rivals hydropower, geothermal and biomass as a source of low-cost electricity. The weighted average regional values for the LCOE of onshore wind in 2013 and 2014 ranged from a low of USD 0.06 to USD 0.07/kWh in Asia, Eurasia and North America to around USD 0.08/kWh in the rest of the world's regions that are deploying significant amounts of wind. Where excellent resources and low cost structures exist, wind power projects are now routinely achieving costs of just USD 0.05/kWh without any financial support.

Biomass-generated electricity can be very competitive where low-cost feedstocks are available onsite at industrial, forestry or agricultural processing plants. In such cases, biomass power generation projects can produce electricity for as little as USD 0.06/kWh in the OECD countries and as low as USD 0.03/kWh in developing countries. The typical LCOE range for biomass-fired power generation projects is between USD 0.05/kWh and USD 0.15/kWh, but where expensive feedstocks, such as woodchips or pellets, or expensive gasifier technology are used, the LCOE can rise to as much as USD 0.20 to USD 0.25/kWh and will require financial support to be economic. The weighted average LCOE by region varies from a low of around USD 0.04/kWh in Asia and Eurasia to USD 0.14/kWh in Europe.

Geothermal electricity generation is a mature, baseload generation technology that can provide very competitive electricity where high-quality resources are well-defined. The LCOE of conventional geothermal power varies from USD 0.05 to USD 0.10/kWh for recent projects. However, the LCOE can be as low as USD 0.04/kWh for the most competitive projects, such as those which utilise excellent well-documented resources or brownfield developments. Most recent projects have been brownfield in nature and past experience with the geothermal reservoir can reduce development risks

BOX 2.1

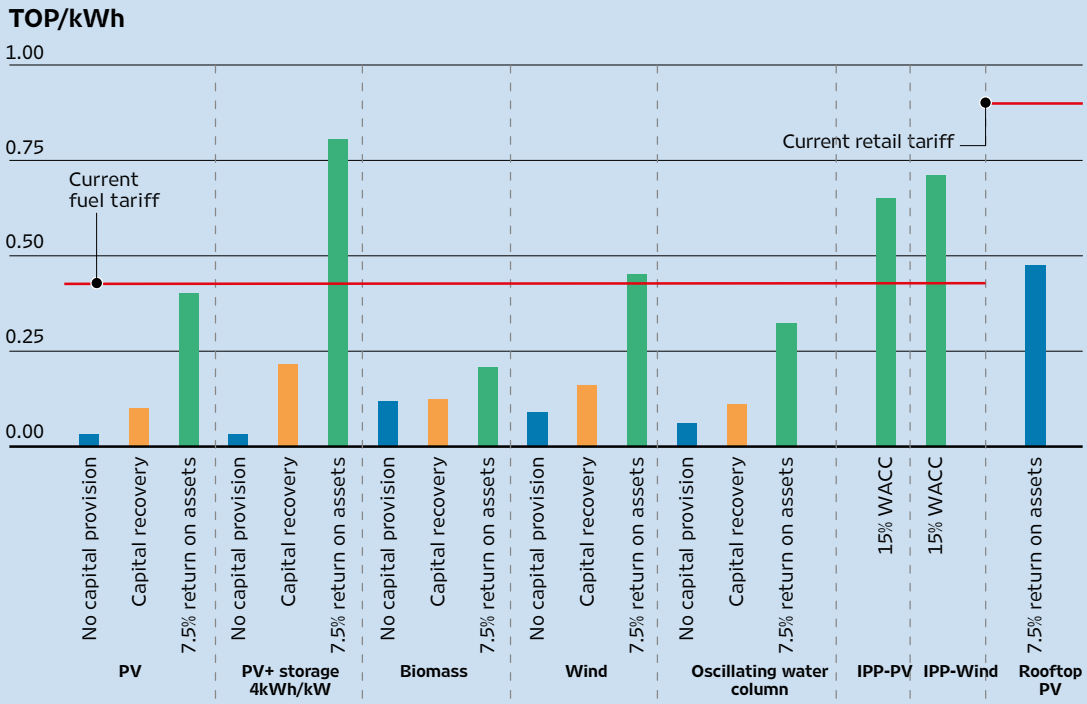
Renewables now the economic solution off-grid and on islands

Despite the fact that installed costs for small-scale projects off-grid, in remote locations and on many islands are higher than in areas close to major markets and with good infrastructure, there is now almost always a renewable solution that costs less than diesel-fired electricity (Figure 2.4). This will have economic, environmental and social benefits. Remote communities and islands will see cost reductions (tariffs range from USD 0.35/kWh to USD 1/kWh or more on remote islands), reduced imports of expensive fossil fuels, improved security of supply and be able to more rapidly meet electricity needs of remote communities due to the highly modular nature of renewables.

By combining renewable technologies in mini-grids to electrify isolated villages and extend grid networks, the variability of supply can be reduced to low levels, thus providing a high-quality, low-cost solution. As an example of the potential of renewables to reduce costs on islands, IRENA has worked with the Government of Tonga to analyse cost reductions from introducing renewables (IRENA, 2015). Depending on whether the projects are financed by grants from development aid (with or without cost recovery so that the asset can be replaced by the country not donors at the end of its life) or privately at a 7.5% real weighted average cost of capital (WACC), the costs for some technologies are significantly lower than current generation tariffs and the distributed generation cost is significantly lower than retail tariffs.

However, the major challenges are often finance-related, as the high cost of capital (which can be two to three times higher for these projects than in developed countries) and high transaction costs for small-scale projects can sink the viability of these projects, even if financing is available for them. Much work therefore needs to be done to address the financing challenges before the economic and environmental benefits of renewables off-grid and on islands can be realised.

FIGURE 2.4: RENEWABLE POWER GENERATION OPTIONS FOR TONGA COMPARED TO GENERATION COSTS AND RESIDENTIAL TARIFFS

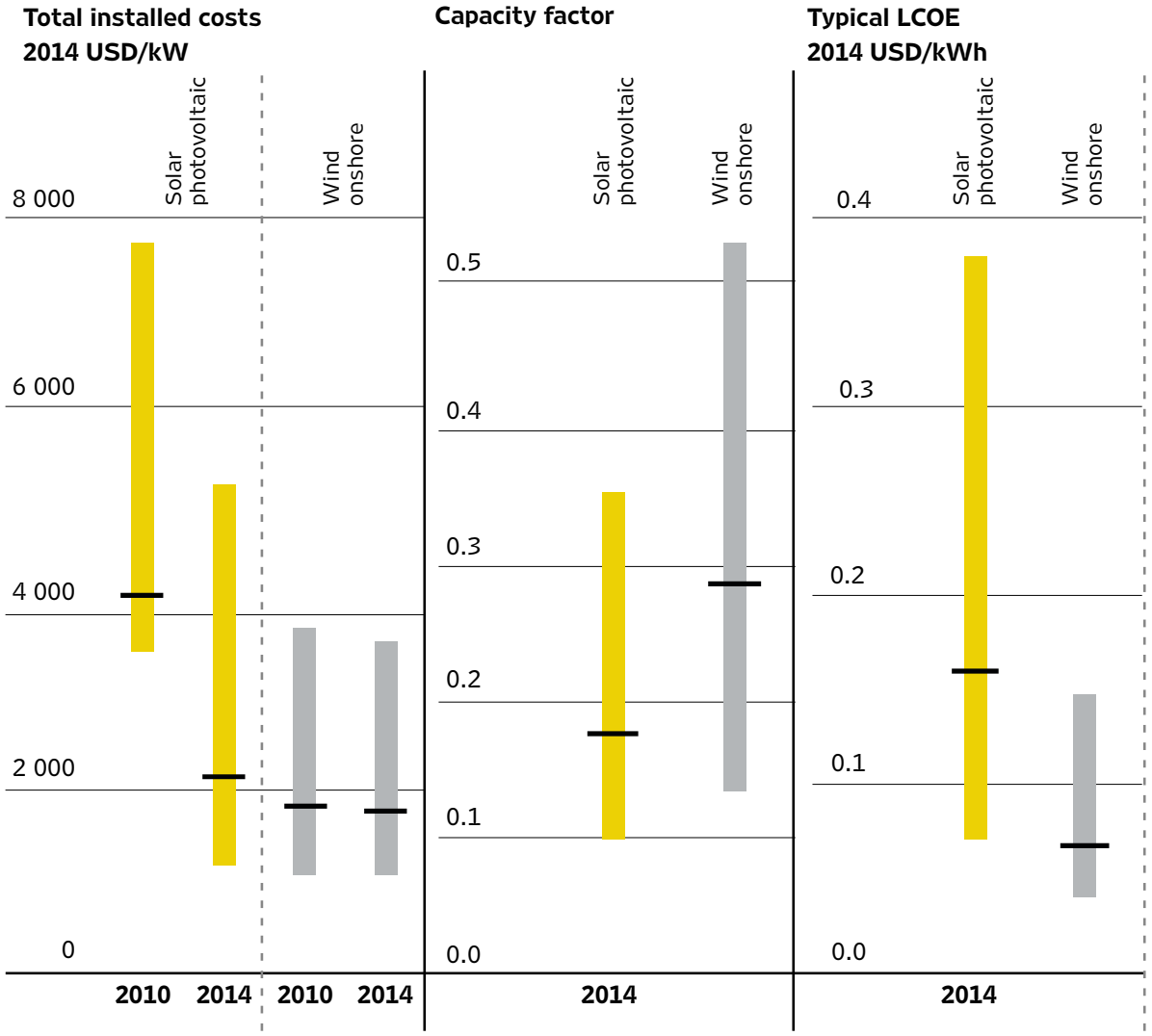


Source: IRENA, 2015.

and some existing infrastructure may already be in place which will also reduce costs. It is important to note that geothermal projects carry a very different risk profile than the other renewable technologies and tailored support policies will typically be required to accelerate geothermal deployment.

The two main CSP systems are parabolic trough and solar towers, although linear Fresnel collector

Figure 2.5: Global typical installed cost, capacity factor and LCOE ranges with weighted averages for utility-scale solar photovoltaic and onshore wind projects, 2010 and 2014

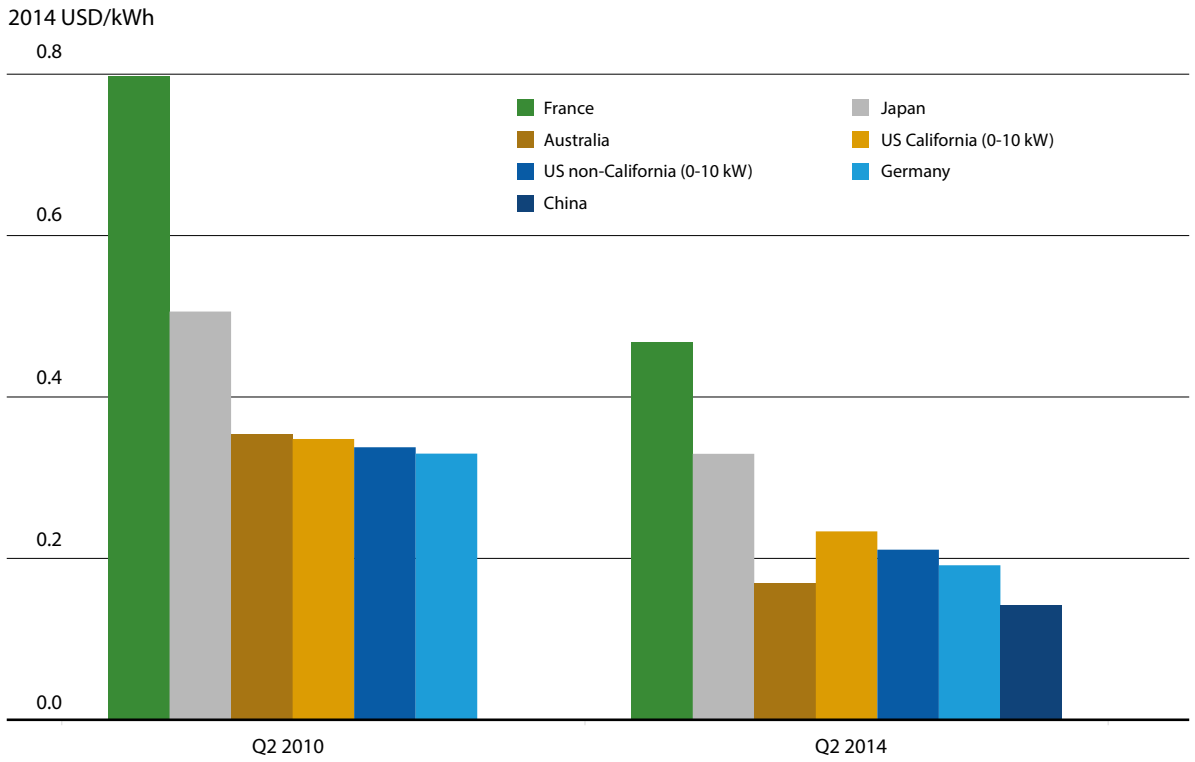


Source: IRENA Renewable Cost Database.

systems and dish systems are beginning to be deployed commercially. The majority of commercial experience so far has been with parabolic trough systems, which have typical LCOE ranges of between USD 0.17 and USD 0.35/kWh, although PPAs have been signed for as low as USD 0.14/kWh where low-cost financing is available. The LCOE of solar towers are estimated to be similar, in the range of USD 0.17 to USD 0.29/kWh. However, given that only a handful of plants with capacity of 10 MW or more were operating at the end of 2014, care needs to be taken in making any comparison with the more numerous parabolic trough plants until more data are available. Looking to the future, and given their modest deployment at commercial scale to date, solar towers appear to have a greater potential for cost reduction. The ability for solar towers to achieve higher operating temperatures with molten salt will also help to improve efficiency and translate into lower costs for thermal energy storage per unit of energy stored. These factors will help drive the LCOE down and make solar towers attractive solutions for providing flexible electricity generation and helping to facilitate the penetration of wind and solar PV by providing dispatchable generation to balance the variability of wind and solar PV when equipped with thermal energy storage.

Although the range of costs for renewable power generation technologies is wide for a given technology, and even for a technology within a particular region, it is striking that virtually all renewable power generation technologies now include significant numbers of projects which

FIGURE 2.6: LEVELISED COST OF ELECTRICITY OF RESIDENTIAL SOLAR PHOTOVOLTAIC SYSTEMS BY COUNTRY, 2010 TO 2014



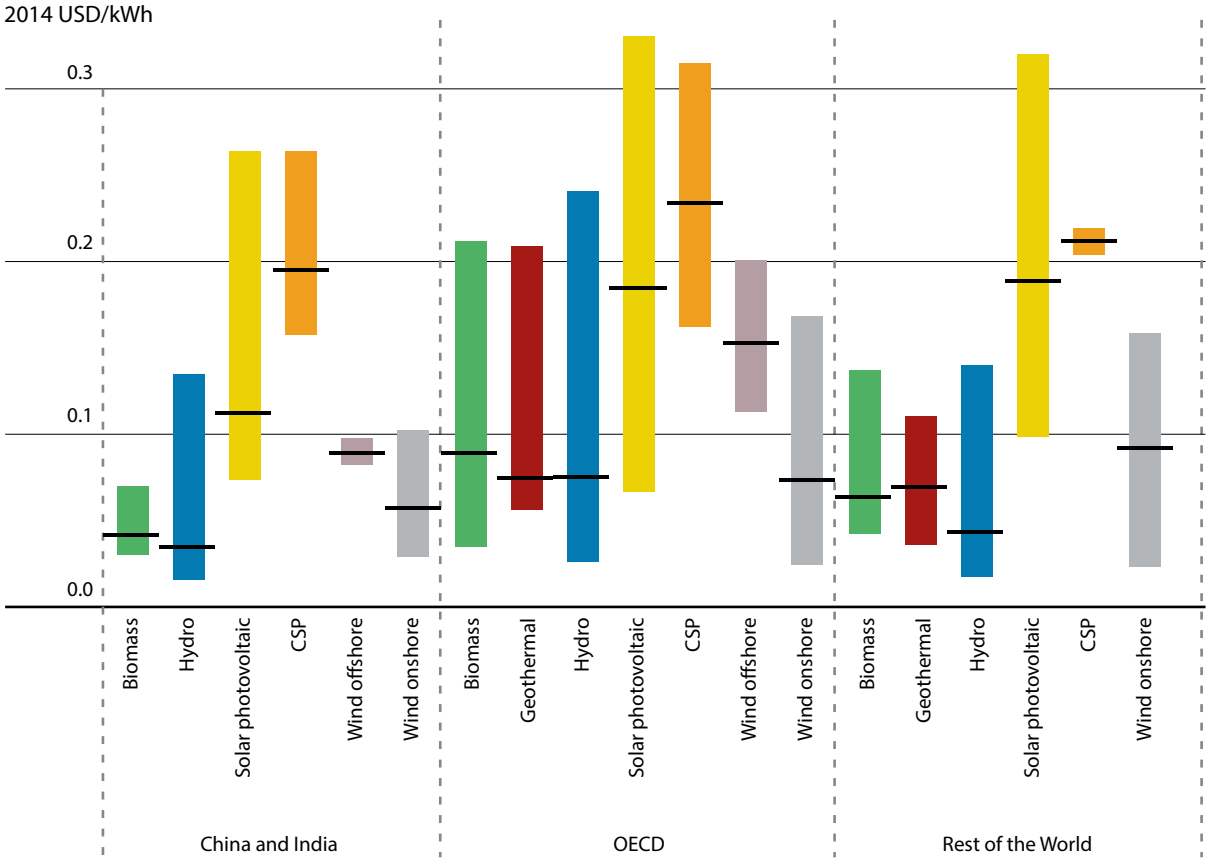
Sources: IRENA Renewable Cost Database; BSW, 2014; CPUC, 2014; GSE, 2014; LBNL, 2014; and Photon Consulting, 2014.

are competitive with fossil fuels without financial support, despite the fact that fossil fuels still do not pay for the local and global environmental damage they cause, or their negative health impacts. Including these costs would significantly improve the economics of renewable power generation costs and has been shown to mean that a doubling of the share of renewables in the energy mix could be achieved at a net saving to society (IRENA, 2014). This is also now true for solar PV, although to a lesser extent than for the other technologies. The exception to this is CSP, which with just 5 GW of installed capacity is in its infancy and will see continued significant cost reduction with continued policy support.

The decline in total installed costs has been driving the decline in the LCOE of solar PV between 2010 and 2014 (Figure 2.5). Although total installed project costs for onshore wind span a narrower range, the lower ends of the total installed cost ranges for utility-scale solar PV and onshore wind in 2014 are now very similar. In 2014, there is also little difference in the global weighted average of total installed costs for the two technologies, despite the fact that total installed costs of utility-scale solar PV were 110% higher on average in 2010. What drives the difference in the LCOE in 2014, given similar average total installed costs, are the different capacity factors that can be achieved by the two technologies. The global weighted average capacity factor for new onshore wind power projects in 2014 was estimated to be around 35%, almost twice that of the estimate for solar PV in that year.

As a result of the lower capacity factors for solar PV, the global weighted average LCOE of utility-scale solar PV is slightly more than twice that of onshore wind projects, despite total installed costs being on average only 25% higher for solar PV. However, the LCOE range for individual solar PV projects since 2012 has increasingly begun to overlap with onshore wind. In 2014, a handful of solar PV projects are estimated to have had a LCOE that matched the global average LCOE of onshore wind. In areas with excellent solar resources, utility-scale solar PV is now likely to provide electricity more cheaply than onshore wind, except where there are also excellent wind resources. However, with more rapid reductions for installed costs expected for solar PV than for onshore wind up to 2020,

Figure 2.7: The levelised cost of electricity by region and technology and their weighted average, 2013/2014



Source: IRENA Renewable Cost Database.

the average gap between the two technologies in terms of LCOE will continue to narrow. The gap would be reduced even more quickly if more solar PV capacity were to be deployed in regions with excellent solar resources than is the case today.

Figure 2.6 presents the evolution of the LCOE for small-scale residential solar PV systems between 2010 and 2014. Similar to the experience in the utility-scale sector, the LCOE for these small-scale systems has fallen rapidly with the declines in solar PV module prices. The average system LCOE of the systems in Figure 2.6 has reached residential electricity price parity in Germany, Italy and parts of Australia. Germany and China have, on average, the most competitive small-scale residential rooftop systems in the world. Germany's residential system costs have fallen from just over USD 7 200/kW in the first quarter of 2008 to USD 2 200/kW in the first quarter of 2014. This is reflected in their low LCOE. The LCOE of solar PV in Australia, despite higher installed costs, is also highly competitive due to the country's excellent solar resources. The LCOE of residential solar PV has declined to between USD 0.14 and USD 0.46/kWh in 2014 in eight major residential markets IRENA has data for. Between 2008 and 2014, the average LCOE in these markets declined by between 42% and 64%.

The levelised cost of electricity by region

In the past, there was a clear hierarchy of costs for renewable power generation technologies, with established renewable technologies, such as hydropower, biomass and geothermal able to provide electricity at low costs at the best sites. However, the large-scale deployment of wind and solar PV since 2000 has seen their installed costs driven down by learning investments at the same time that technology improvements have improved yields, resulting in LCOE declines. This resulted first in onshore wind and now, to an increasing extent, in solar PV becoming sources of low-cost electricity. Solar PV on average still remains more expensive, but costs are continuing to fall and the

same generalised competitiveness of solar PV in areas of excellent solar resources will emerge in the next three to five years.

Figure 2.7 compares the weighted average LCOE and range of renewable power generation technologies by country/region. There are significant differences in the cost ranges for different technologies in different regions due to the very site-specific nature of renewable resources and project costs. A regional and country-level analysis of costs is therefore critical to understanding costs and their implications for policy-makers.

There is no substitute for collecting up-to-date cost data from local markets. It is inadvisable to assume that local costs for different technologies in local contexts can be extrapolated from data in neighbouring countries or regions, as there are a range of variables that mean local cost structures are likely to differ. These can include: the maturity of the local market for a given renewable technology; local infrastructure availability; local materials prices; the number of local project developers with renewable project development experience; labour rates; regulations and permitting procedures; skills shortages; and a range of other factors. Not collecting these data can lead to unrealistic current cost and cost reduction potential assumptions that can result in poor policy-making and in inefficient policies.

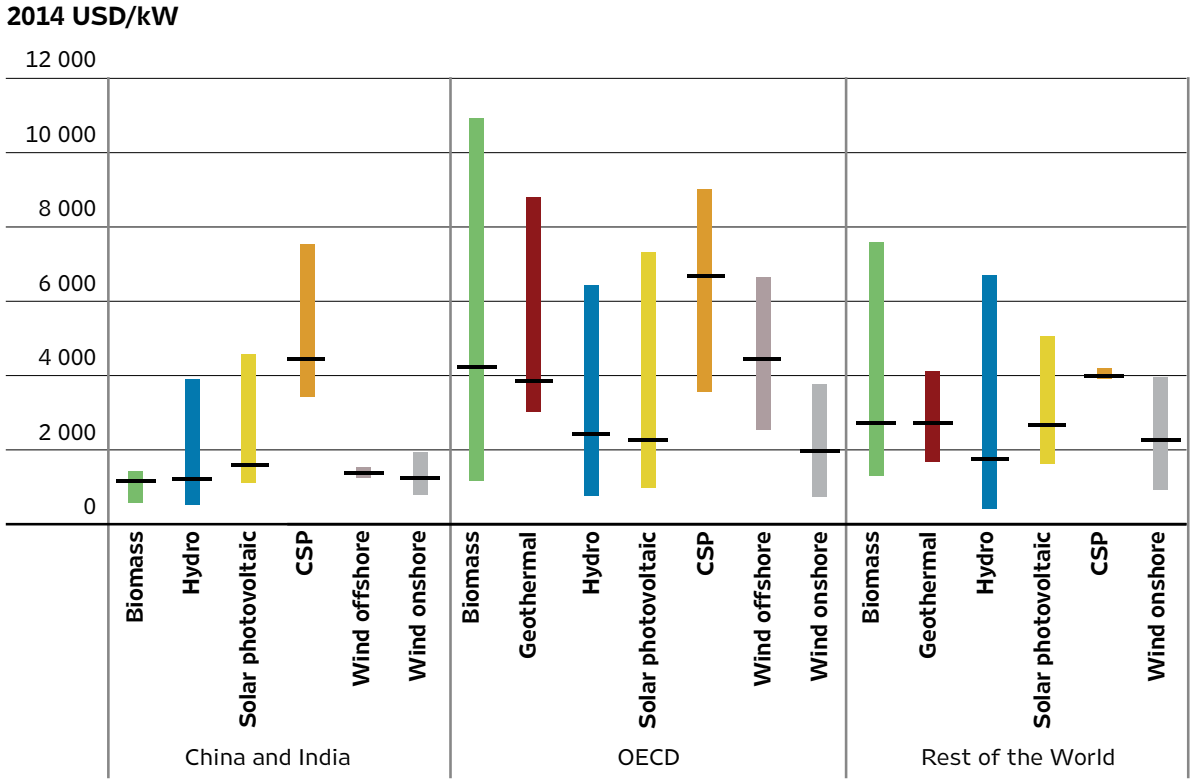
China and India, where IRENA has been able to collect a large number of project data points, have some of the most competitive renewable power generation project development costs in the world and this translates into very competitive LCOEs, even for wind where the local resource quality is not ideal. Elsewhere, South America is emerging as a dynamic new market for renewable power generation, as efficient policies are ensuring that competitive installed costs are being combined with world-class renewable resources to produce very competitive LCOEs.

China is the largest global market for renewable power generation technologies. In China, the large- and small-scale hydropower projects are the most competitive, followed by biomass, wind power, and solar PV. However, with China's abundant coal reserves and relatively low installed costs for fossil fuel-fired plants, the renewable energy industry still in some cases needs support to compete with incumbent technologies. Hydropower in China has a weighted average LCOE of around USD 0.04/kWh while the range for biomass is between USD 0.05 and USD 0.06/kWh. Wind is also very competitive by global standards, with project costs in the range of USD 0.05 to USD 0.10/kWh and weighted average costs of around USD 0.06/kWh. The LCOE of utility-scale solar PV has declined rapidly from an average of around USD 0.24/kWh in 2010 to just USD 0.11/kWh in 2014, although the data for 2014 have yet to be confirmed and are subject to revision.

India, like China, benefits from a competitive cost structure for renewables, although currently to a lesser extent for solar PV. The financing costs in India, however, are somewhat higher than in China and this has a material impact on the LCOE of projects. With a number of projects coming online, hydropower is still the lowest-cost renewable power generation option in India, with weighted average hydropower costs of between USD 0.04 and USD 0.05/kWh for small- and large-scale projects. Large-scale wind projects have average costs of around USD 0.08/kWh, with a range between USD 0.05 and USD 0.10/kWh, while small-scale (<5 MW) projects have weighted average costs of USD 0.09/kWh. Biomass-fired power generation costs averaged between USD 0.045 and USD 0.06/kWh, assuming feedstock costs of between USD 1.3 and USD 2.5/GJ. The weighted average LCOE of utility-scale solar PV has fallen to around USD 0.13/kWh in 2014, but a wide range in costs still exists and projects are still being built that have an LCOE of twice this average.

In the rest of Asia the weighted average costs for biomass, solar PV and wind are all higher than in India and China, given their competitive materials costs and large engineering bases, low cost manufacturing and local content costs. The Philippines and Indonesia both make extensive use of their excellent geothermal resources and the estimated LCOE for their brownfield geothermal power projects is around USD 0.05/kWh, assuming these projects can meet their projected high capacity factors of 80% to 90% over the entire project life. The average LCOE of hydropower

Figure 2.8: Typical ranges and weighted averages for the total installed costs of utility-scale renewable power generation technologies by region, 2013/2014



Source: IRENA Renewable Cost Database.

projects in other Asian countries are very similar to those in China and India and are estimated to be around USD 0.05/kWh.

New renewable power generation capacity additions in Central and South America used to be almost exclusively based on biomass and hydropower, given abundant resources, allowing very competitive electricity generation. However, the region also has world-class wind and solar resources. As the long lead times and environmental requirements make adding more hydropower difficult and time-consuming, the fall in wind and solar PV costs has seen a growth in their deployment to meet growing demand and/or to help stabilise electricity supplies in the face of challenging hydrological conditions. This is typically occurring against a background of no, or minimal financial support.

The installed costs for wind in Central and South America are higher than in China and India, but good wind resources in many locations mean the weighted average LCOE is around USD 0.08/kWh, with a typical range between just USD 0.05/kWh and USD 0.10/kWh. Brazil's very successful auction system will see these average costs fall in the next few years as the contracted-for capacity is built. Although only a small sample of large-scale solar PV projects have provided sufficient data to be analysed, excellent solar resources in Peru and Chile have resulted in exciting developments in South America. In Chile, solar PV plants are now being built as merchant plants to feed into the grid, as the excellent resources and low installed costs mean they are a competitive option to feed into the daily power market. The average LCOE for the projects in the IRENA Renewable Cost Database is estimated to be just USD 0.11/kWh in 2014. The large-scale projects in areas with excellent solar resources allow very high capacity factors (27% or more) compared to the global average, and mean that Central and South America will see strong growth in solar PV deployment in the coming years, with projects as competitive as anywhere in the world, most without any significant financial support.

The available data for renewable projects in Africa are thinner than for some other regions, but the costs follow a similar pattern to Latin America, with the exception that the LCOE of large hydro tends

to be higher than for small hydro. Insufficient data are available to provide a definitive explanation of this finding, but poorer infrastructure, high grid connection/reinforcement costs for remote projects and multi-purpose dams probably all contribute. Collecting more data for Africa to verify whether these data are accurate and the reasons for the observed pattern is a priority.

The total installed cost ranges for renewable projects (Figure 2.8) in different regions follow a similar pattern to the LCOE cost ranges presented in Figure 2.7, with the exception of solar PV and biomass for power generation. The total installed cost ranges for solar PV are narrower than the LCOE as the wide variation in capacity factors results in wider LCOE ranges. A different pattern occurs for biomass-fired power generation in OECD countries, where a wider range of installed costs are associated with higher capacity factors resulting in a narrower range in the LCOE than that implied by total installed costs.

The recent declines in installed costs for wind and solar PV mean that renewables now often have total installed costs per kW similar or lower than fossil fuel technologies, except where low-cost gas-fired plants are being installed.

From the levelised cost of electricity to electricity system costs

As discussed in Chapter 1, this report uses a range of cost metrics to analyse the evolution of the costs of renewable power generation technologies. Each metric, whether it be equipment costs, total installed costs or LCOE, brings its own insights and can be used to identify differences in costs and their evolution over time. However, there is no one "true" cost metric that can provide all the information required to analyse the competiveness of renewables.

Different metrics can identify significant cost differences between projects of a given technology within a country, between different technologies within a country and between the same and different technologies across countries. However, just because one cost metric is higher in one region or country than another or different between technologies doesn't mean that the cost structure is necessarily less efficient. As already discussed, site-specific factors can have a significant impact on overall costs, as do local materials prices, infrastructure, etc. A detailed analysis of equipment costs and local cost drivers is required to attempt to identify general levels of competiveness. However, large datasets that contain a detailed breakdown of different cost components (*e.g.* installation, project development costs, land costs, etc.) for different cost metrics utilising the same boundaries across technologies and countries are extremely rare. The end result is that any analysis of the costs and relative competitiveness of renewables must come with a significant disclaimer that the comparisons made are only indicative, due to the imperfect information available and the limitations of individual metrics.

This is in part why a range of cost metrics are used in this report. Although the underlying reasons for cost differences may not be evident, large differences in costs (*e.g.* BoS costs for PV systems) can at least be identified and provide the basis for future, more detailed analysis of why these cost differentials exist and – critically, from a policy-making perspective – what might be possible to reduce cost differentials to the lowest feasible level. The "lowest feasible level" is measured while taking into account differences in fundamental underlying cost drivers (i.e. resource quality, local materials and labour costs, maturity of the local market, etc.), although this "normalisation" is in itself a difficult analytical exercise that is only approximate.

Cost metrics and minimising electricity system costs

As a metric, the LCOE of electricity is a useful tool for comparing technologies with similar characteristics and generation profiles in a specific market. However, it has limitations and is not a definitive metric for discussing relative costs. In particular, in its simplest form, it doesn't take into account the value of electricity generated at different times, the implications for the electricity transmission and distribution system or the risks to the project's total costs over the project's life (*e.g.* the risks associated with fuel price volatility, physical disruptions to fuel supplies, or drilling risks

for geothermal projects). These issues can have a material impact on the LCOE between different projects and also the risks associated with the actual LCOE of the project over its economic life diverging significantly from the estimated LCOE at the time the decision to invest is taken, whether it be renewable, fossil fuel-fired or nuclear.

The only robust way to identify the lowest-cost combination of new capacity to build over time is to undertake detailed system level modelling. Using the best possible input assumptions for the costs and performance of renewables is critical to the quality of the results from these types of modelling exercises.

This leads to one of the key benefits of collecting detailed cost and performance data for renewable power generation technologies. They can be used as input assumptions for the detailed system modelling to minimise overall electricity system generation costs in the long-run[10] when adding new capacity, subject to constraints on local and global environmental pollutant emissions (where applicable), energy security goals, etc.

This modelling needs to take into account: highly granular load curves (demand) through time (down to as short as 15-minute time intervals) that vary by day and season, as well as their projected growth over time; existing generation plants and their characteristics (*e.g.* efficiency, fuel and O&M costs, feasible ramp rates, availability, etc.); as well as the characteristics of potential new capacity. Such simulations can provide a better estimate of the lowest-cost expansion plan for an electricity market, but can't remove all uncertainties, such as unexpected changes in demand growth, load profiles, fuel costs, cost overruns on projects, etc. As a result, even these simulations are subject to significant uncertainty and scenario analysis needs to be used to identify the sensitivity of the results to the underlying risk factors affecting total system costs. In centrally planned electricity systems this process will be used to determine expansion plans. However, where electricity markets are open to new entrants with few or no barriers, the decision of whether to invest, in what and when, is a commercial decision that also contends with the uncertainties of what other potential market actors may do. In either a centrally driven system or a more liberalised one, miscalculations are not uncommon, leading to increased costs for consumers and/or to shareholders losing money.

Detailed system level modelling is required to understand the dynamics of an individual market and the lowest-cost expansion pathway. These results are, by definition, only applicable to the market; however, there are three essential components of this modelling that are relevant to moving beyond a simple LCOE. These are:

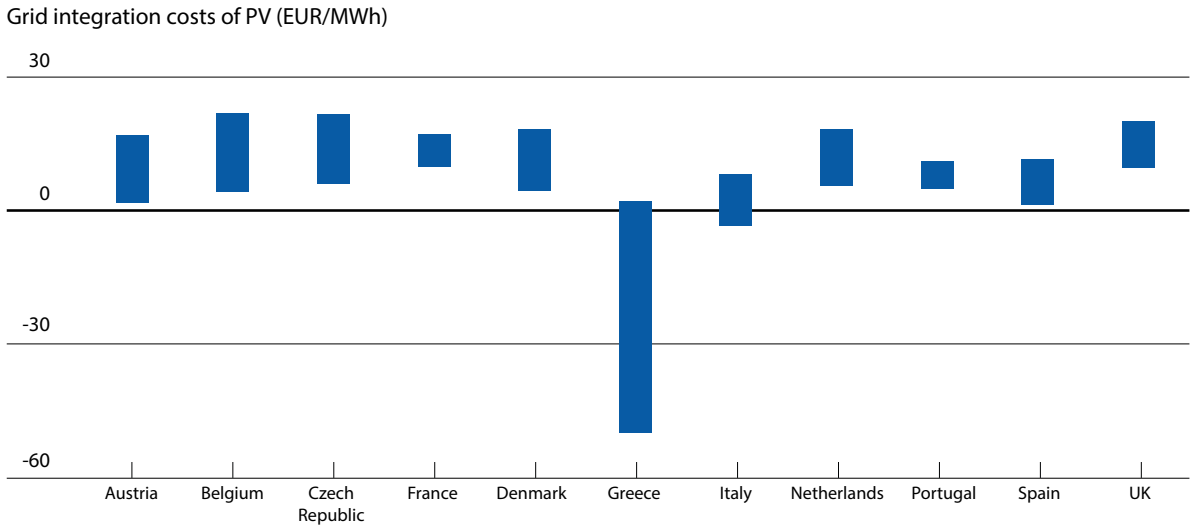
- The value of electricity varies over time for the existing generation mix, and will vary in the future as new capacity is added or retired.
- System level interactions occur when new capacity is added; these can reduce costs or increase them.
- The risk profiles of different technologies need to be taken into account. Certainty around costs and performance should be rewarded, but sometimes it is not.

The first point is critical; the simplest version of LCOE assumes that all electricity generated is of equal value. However, due to system constraints, peak loads and demand change rates, this is not true and the value of generation will vary over the course of each day. Given that peak electricity demand is more expensive to meet than more constant demand (as plants will operate for relatively shorter periods throughout the year), the value of electricity during these peak times is typically higher. As a result, plants that can ensure a higher share of their generation occurs during these peak periods will receive greater remuneration.

For renewables, when system peaks occur and the ways they coincide with different renewable power generation production profiles will have a large impact on the additional value over and above average system prices. In hot climates with high air conditioning loads, solar PV can help significantly reduce afternoon peaks and its production profile is quite complementary. However, it doesn't address

[10] *The optimisation of the electricity system in the short run assumes a time frame when no new capacity can be added and is not relevant to the discussion in this report, which compares the costs of new capacity options.*

Figure 2.9: Integration costs for solar PV in the European Union for between 2% and 18% of electricity generation with demand response



Source: Pudjinato, 2013.
Note: The lower range limit is for 2% solar PV penetration and the upper limit is for 18% solar PV penetration.

the typical early evening peak demand as families return to their homes and this will require a mix of technologies to meet those demands at lowest cost. Thus, relatively more flexible plants will more often have the opportunity to capture this extra value of meeting peak demand.

A couple of examples are useful to understand these points and to highlight the complex interactions as new capacity is added and the need for integrated system modelling. In California, time-of-use tariffs for electricity customers incentivise them to adjust to peak system constraints or the cost of generation. Solar PV's generation profile means that the value of the electricity generated by solar PV is 30% to 50% higher than what a flat tariff structure would imply (Borenstein, 2007). However, adding significant amounts of solar PV to the system will alter the timing of peak demands so that as solar PV penetration grows, the time of the net peak (after subtracting solar PV output) will shift. This can be addressed in a number of ways: by improving demand response; by adding storage to solar PV systems; or by other generating options that can meet these new peaks. CSP,[11] with its ability to add low-cost thermal energy storage, could be an important part of the solution to these emerging flexibility needs, despite higher LCOE metrics than some other renewable technologies today, but it is competing with rapidly falling battery costs for solar PV. Following the California example, the marginal value of additional CSP with storage at a 40% renewables target would be between USD 0.096 and USD 0.109/kWh, while the marginal value of new solar PV when already contributing about 14% of the total generation target of 40% (i.e. slightly more than one-third) would drop to only be between USD 0.032 to USD 0.047/kWh (Jorgenson, 2014). Thus, once a high level of penetration of variable renewables is reached, more flexibility will be rewarded.

Adding new power generation capacity to an electricity system has an impact on electricity flows and system costs; this is true for any type of power generation technology. The key impacts are:

- Impact of electricity flows across transmission networks, which may cause or alleviate transmission constraints or be absorbed without major issue.
- Impact on local distribution network flows, which may cause or alleviate distribution system constraints or be absorbed without major issue.
- Impact on overall system management, stability and reserve requirements.

Adding new power generation capacity will have an impact on electricity flows over the system depending on their location. Renewables have an advantage in this respect in that they are more

[11] *This would also be true to a different extent for other flexible renewable technologies such as geothermal and biomass for power.*

modular and can be added in economic sizes (*e.g.* 5-20 MW) that are smaller than fossil fuels (where unit sizes are 250 MW or more) or nuclear, where economic sizes are one GW or more. This allows them to be more easily integrated into the grid and nodal pricing on the transmission grid can provide an economic incentive to locate them to alleviate grid constraints. The same types of issues play out at the distribution level, although the issues of dealing with distributed generation attached to the low voltage distribution network are somewhat different. In particular, some investments will be needed to allow for two-way flows where previously only consumption occurred and to manage flows at the distribution level.

In addition, spinning reserve requirements may be lower with renewables, as the loss of any single, relatively small wind farm or solar plant (e.g. due to the plant tripping offline, sub-station loss, etc.) will result in a smaller disruption than loss of larger blocks of fossil fuel or nuclear capacity. The system will still need adequate flexibility to deal with the variability of solar PV and wind generation, much like it needs to deal with demand changes, but the geographic dispersion and the smoothing effect of two different renewable resources and technologies can reduce this requirement.

A partial analysis of the additional costs of integrating significant levels of solar PV generation in Europe, taking into account capacity adequacy and reserves, upgrading of the main European Union (EU) transmission network, the cost of reinforcing the distribution network and the impact of solar PV on network losses (beneficial at low penetration rates), indicated average integration costs of around USD 0.02/kWh for 10% of EU generation from solar PV, rising to around USD 0.025/kWh for 18% of EU generation coming from solar PV. Taking a more holistic approach to integrating solar PV by including demand response as an additional source of flexibility would reduce these costs by an average of 20% (Figure 2.9). This also has to be put in context of today's retail electricity rates in the EU, which range from a low of around USD 0.11/kWh to USD 0.40/kWh and averaged USD 0.27/kWh in the first half of 2014.

The integration costs are lower and even negative for low levels of solar PV penetration in Greece and Italy, because the production profile of solar PV helps alleviate peak electricity demand. The difference between Greece and Italy in integration costs also highlights the need for system specific modelling, as the order of magnitude of savings at low levels of penetration and then costs at higher levels are very different.

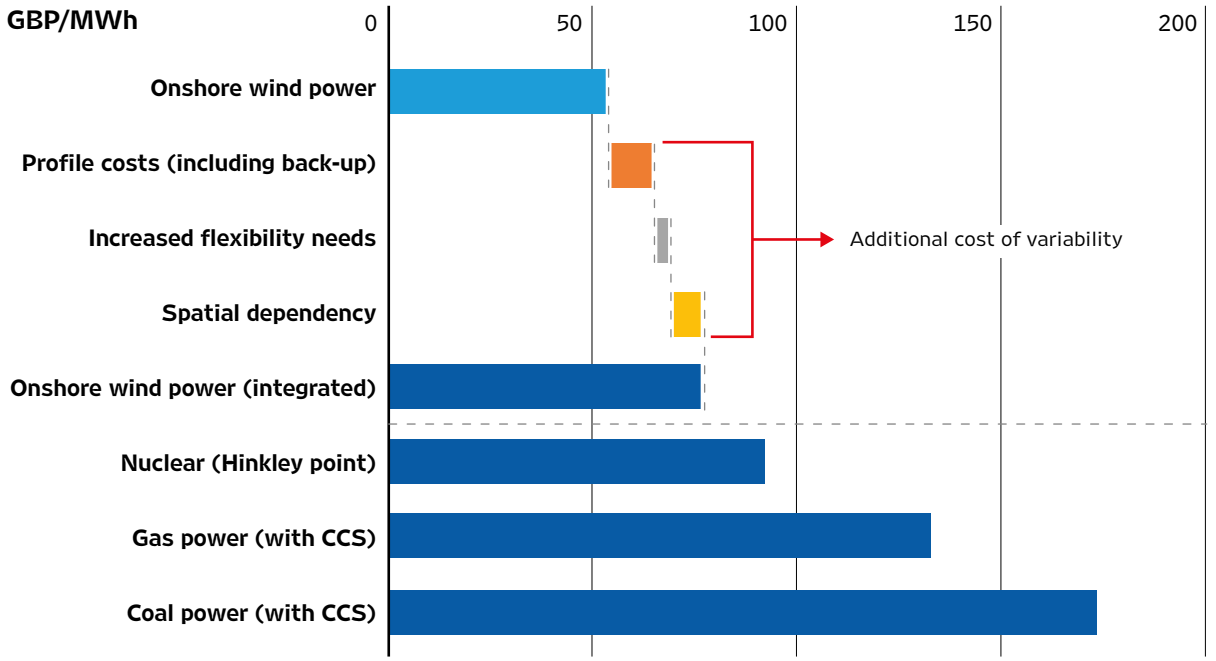
A range of studies have been undertaken that try to account for the additional benefits and/or costs of adding variable renewables to the electricity mix by extending the LCOE analysis beyond generation only. The drawback of many of these analyses is that they often simulate the system in a static way, or one that is not related to the overall policy context.[12] However, these analyses may provide useful insights for future analysis.

There is much debate about the additional system integration costs of variable renewables. It is important to note that all new capacity, not just renewable capacity, has an impact on the way the system operates and will impose costs and benefits on existing generators and the system as a whole. Solar PV and wind power are often suspected of significantly increasing system operation costs because of their variable nature. This misses the point that baseload nuclear and coal-fired plants lack the flexibility (either technically or from an economic perspective) to respond to the existing variation in demand and are supplemented by "mid-merit", "shoulder" or "peaking" plants that can meet this variability. These more flexible plants, typically gas- or oil-fired today, generally have lower installed costs and much higher fuel costs. Some will run for several thousand hours a year and others for just several hundred hours a year to meet exceptional peaks in demand.

In a system with higher shares of variable renewables, the inflexible plants will become more of a drag on the electricity system. The role of plants that operate at constant rates throughout the year will decline and greater value will be

[12] *A common problem remains the tendency to simulate renewables penetration by a single technology, without taking into account the broader policy context. For instance, looking at system costs when raising the share of an individual renewable technology (e.g. to 15%), will yield very different system cost results than examining changes in overall system costs when meeting overall goals for renewable energy penetration (e.g. raising overall renewable shares to 50%). This can lead to bias in the comparison of analysis as the results of individual studies are typically not linear or additive, overestimating total costs.*

Figure 2.10: The LCOE of onshore wind including integration costs, nuclear and gas-fired power plants with CCS



Sources: Grubb (1991), Hamidi et al. (2011) and Hirth et al. 2015.

Note: Generation cost data is based on the UK Department of Energy and Climate (DECC) calculator for low carbon scenarios (assumed discount rate of 10 %). For nuclear power, costs are estimated from the guaranteed strike price for the planned Hinkley Point C nuclear plant (GBP 92.5 per MWh for 35 years, fully indexed to inflation). Wind integration costs are estimated conservatively according to the higher cost values in Grubb (1991), Hamidi et al. (2011) and Hirth et al. 2015; assuming wind shares of 30-40%. For lower shares integration costs would be much less. Also, additional measures such as smart grid technologies, demand response, energy storage and more flexible generation technologies would reduce integration costs

placed on a heterogeneous mix of plants with more flexible capabilities. What is critical is that this mix of plants provides the lowest-cost solution for overall electricity generation.

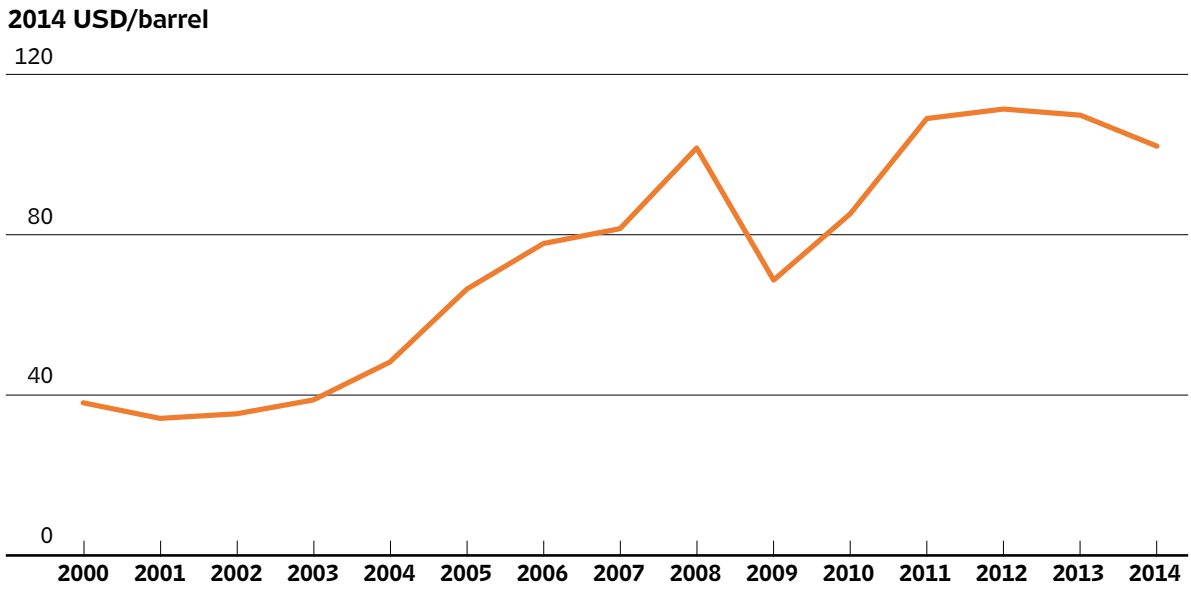
In 2013, Denmark, Germany and Spain had a generation share of renewable electricity of 56%, 25% and 42%, respectively, with at least half of power generation capacities being renewable. The examples of Denmark, Germany and Spain show that up to about 20% to 25% variable renewable energy (VRE), specifically solar PV and wind, in total annual electricity supply do not pose a major challenge and can be easily accommodated in most power systems. Higher VRE shares pose challenges and increasingly require rethinking of the power system operation and planning. Already at moderate average VRE shares, instantaneous penetration levels can become very high in some hours of a year, and VRE supply can sometimes even exceed electricity demand.

However, these challenges can be met and there is wide consensus that the challenges of VRE variability create no insurmountable technical barriers to high VRE shares, however, the specific properties of VRE cause additional costs at the system level (Sims et al. 2011, Milligan and Kirby 2009, Holttinen et al. 2011, Milligan et al. 2011, Katzenstein and Apt 2012, Ueckerdt et al. 2013, IEA 2014, Hirth et al. 2015).

Integration costs are not specific to VRE. In principle, every generation technology imposes additional costs on the power system. However, variable renewables have three characteristics that may require specific measures and additional costs to integrate these technologies into current power systems, they are:

» Geographic location: In large countries, increased investment in transmission and distribution lines might be required if the best renewable resources are located far from demand centres. In transmission networks, the resulting grid costs tend to be less than around USD 0.013/kWh of VRE at high wind shares of about 30% to 40% (DENA 2010, Holttinen

Figure 2.11: Brent Crude Oil Price (Annual Averages), 2000 to 2014



Sources: World Bank, 2015 and US EIA, 2015.

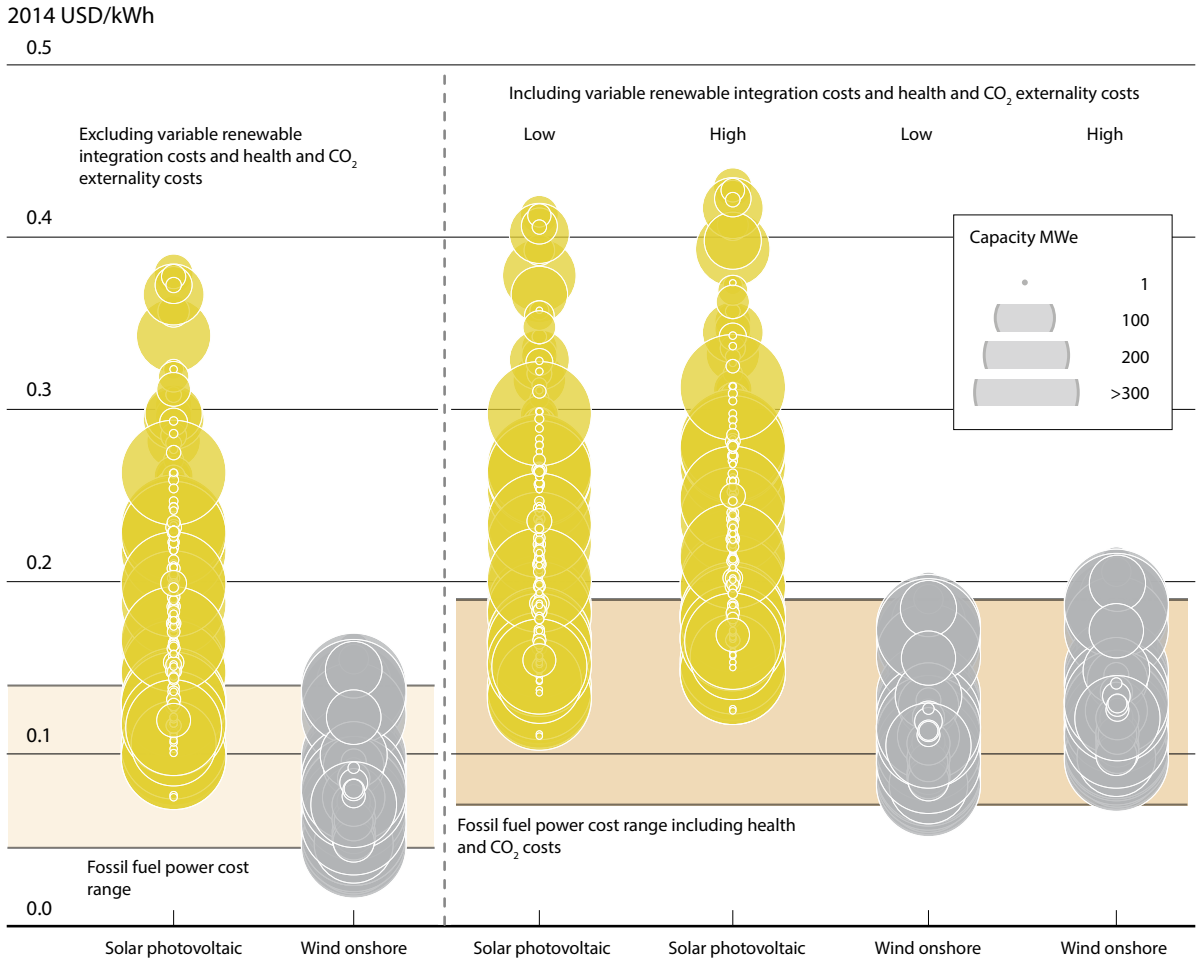
et al 2011, NREL 2012, Hirth et al. 2015). In distribution networks, small wind turbines or solar PV systems can actually decrease the costs of grid enhancement at low levels of penetration. The estimated savings in Europe for low levels of penetration are between USD 0.003 to USD 0.007/kWh, but costs increase to up to USD 0.012/kWh with VRE penetration levels above 15% (Pudjianto, et al. 2014).

» Unplanned short-term variability: If forecast VRE generation deviates from actual production in day ahead markets, bearing in mind that the electricity system has to be balanced in real-time to ensure voltage remains within limits (i.e. over seconds and minutes) additional spinning reserve will be required. Improved forecasting techniques and bundling VRE generation with hydropower or biomass can reduce these variability costs to very low levels, yet some unpredictability remains. Even though this impact receives much attention in the literature and public debate, the required flexibility costs USD 0.008/kWh even at high wind shares (Holttinen et al., 2011, IEA 2014; Hirth et al. 2015).

» Long-term variability: By definition, VRE doesn't provide an even level of generation over the year. The system therefore has to have in place sufficient capacity to meet demand when the sun isn't shining and the wind isn't blowing (VRE has a low so-called "capacity credit"). If the combination of VRE and this additional capacity has higher average system costs than a traditional system with baseload, mid-merit and peak plant, then costs may increase. These are sometimes referred to as profile costs and can range from USD 0.02 to USD 0.033/kWh at high wind and solar power shares of 30% to 40% (IEA, 2014; Hirth et al. 2015). Note that a mix of wind and solar PV significantly decreases these costs. This cost component can also be reduced by peak shaving through demand-side management (IRENA, 2013).

Taking into account the interaction of these factors, integration costs are estimated to range from negative or very small values for low levels of VRE penetration, but can rise to between USD 0.035 to USD 0.05/kWh for 40% penetration of VRE. These integration costs are simply a guide, as actual costs will vary significantly depending on system configurations and where the renewables are deployed. In a VRE-friendly power system consisting of flexible generation plants, flexible demand (including demand side management), and strong grids then costs will be much lower even at these high levels of penetration. Most importantly, as can be seen in Figure 2.10 and Figure 2.12, although VRE integration costs can increase the LCOE of renewables, they are still typically the lowest-cost solution for a low carbon future. That is before

FIGURE 2.12: THE LCOE OF VARIABLE RENEWABLES AND FOSSIL FUELS, INCLUDING GRID INTEGRATION COSTS (AT 40% VARIABLE RENEWABLE PENETRATION) AND EXTERNAL HEALTH AND CO_2 COSTS



Sources: IRENA Renewable Cost Database and IRENA, 2014.

taking into account that innovative grid operations and regulatory frameworks can significantly reduce grid integration costs by harnessing the existing technical flexibility potential.

Another important factor that needs to be taken into account when using LCOE as a metric is that it often isn't used in a way that takes into account the additional costs of unpredictable future prices for fossil fuels.[13] Renewable power generation technologies typically have relatively lower risk profiles than for fossil fuel plants, as most of their costs are known upfront and variable O&M costs typically evolve in predictable ways related to overall labour costs and inflation in the economy. This has important implications, because all else being equal, more predictable costs and hence rates of return should expect lower rates of return than risky investments. Investors should in principle demand higher rates of return to allow for unpredictable future costs associated with fossil fuel prices and CO_2 prices (EWEA, 2009). What this means in practice is that the discount rates used for discounting future fuel expenditures back to current values are too high and don't adequately take into account the fuel price risk.

Greater uncertainty about future fuel prices means that these future costs should not be discounted at the same rate as more predictable cash flows. For gas prices, the historical fuel price variation is significant and using an appropriate discount rate to take into account these risks, rather than a single discount rate for capital and fuel expenditures, increases the LCOE of a gas-fired power plant by as much as 85% (EWEA, 2009). However, even this approach is limited in that it is still capable of

[13] *The important issue here is the difference between risk and uncertainty. In economic parlance, risks are characterised by some statistical relationship that allows investors to price in the variability due to risk and demand an appropriate rate of return. Uncertainty or unpredictability can't be systematically accounted for and can lead to sub-optimal decisions, or deferment of investment in the hope of learning more.*

underestimating the true costs of fossil fuel price volatility over the life of the project if volatility over the period departs significantly from the long-run average.

These issues should be taken into account when comparing the LCOE of renewable technologies to today's costs for fossil-fuel fired electricity generation technologies. For a gas- or coal-fired power plant with an economic life of 25 to 30 years, these fossil fuel price risks can be very significant. This is particularly true for natural gas, as forward markets don't come close to providing generators the opportunity to hedge their future fuel costs for the life of the plant. Coal-fired power plants that have captive sources of coal can insulate themselves to a greater extent, but with an increasing percentage of new coal-fired plant build being based on imports, price volatility for these plants remains a real risk.

Falling oil and gas prices at the end of 2014 therefore don't substantially alter the emerging competiveness of renewables. They may or may not be a short-term decline, but the market doesn't know with any certainty what the trend will be for the life of a new power plant built in 2015. With supply and demand for oil and gas relatively evenly balanced, price swings can be large and sudden in either direction. It is also important to remember that Brent oil priced at USD 50 or 60/barrel is not cheap compared to what was the norm 10 to 15 years ago (Figure 2.11) and a similar story is true for natural gas prices in Europe and Japan. As a result of future price uncertainty and volatility, relatively low current oil prices do not fundamentally alter the conclusion that renewables are the economic solution off-grid for the life of the project. At the same time, the growing decoupling of natural gas prices from oil prices means that lower oil prices will not necessarily have a large impact on natural gas prices, as these are increasingly driven by regional market fundamentals.

From electricity system costs to societal costs

LCOE is often formulated based on costs to individuals and corporations and doesn't factor in costs arising from market failures. In the energy sector, the largest externalities that are typically not priced by the market are the local and global environmental and health damages caused by fossil fuel use. These costs are not borne by the energy supplier or consumer, but they are paid for by society as a whole, for example through higher healthcare costs, increased natural disaster costs, lower labour productivity, reduced life expectancy and premature deaths.

There has been extensive analysis of the external costs of negative health impacts associated with outdoor air pollution from fossil fuel combustion and indoor air pollution from the use of coal and traditional biomass. Significant analysis has looked at the premature deaths attributable to urban outdoor air pollution due to energy-related emissions from vehicles and from power generation. Other important external costs, such as damage to ecosystems due to air pollution or noise from urban transport, have received somewhat less attention and are more difficult to analyse (IRENA, 2014).

The impacts are hugely significant. About 1.1 million people – mainly women and children – are dying annually from illnesses related to indoor air pollution from the use of different types of solid fuels. A further 0.9 million people per year die of indoor air pollution from the inefficient, poorly ventilated combustion of traditional biomass in the home. In Africa, pneumonia attributable to cooking smoke kills 500 000 children younger than five years old each year.

Another 1.5 million people die each year from pollution (mainly particulate matter) caused by urban transportation. According to the World Health Organisation (WHO, 2008), coal-related air pollution deaths have reached 1 million people per year. China accounts for half of this total.

The indicative external cost range associated with these human health impacts is estimated at USD 325-825 billion per year worldwide in 2010 (IRENA, 2014). This includes the effects for emissions of particulate matter (PM 2.5), mono-nitrogen oxides (NOx) and sulphur dioxide (SO_2) from fossil power generation, as well as PM 2.5 and NOx emissions from light-duty vehicles and indoor air pollution

associated with domestic use of coal and traditional biomass.

Added to these costs are the external costs associated with carbon dioxide (CO_2) emissions stemming from the costs of climate change. The range of costs associated with climate change externalities is high, reflecting uncertainty about the rate and severity of the negative impacts of climate change under different scenarios. To manage this uncertainty, IRENA has analysed the impact of the estimated avoided external costs of CO_2 emissions for 26 countries, assuming external costs of USD 20/tonne of CO_2 and also USD 80/tonne of CO_2 to allow for uncertainty over the potential costs of climate change.

The combined costs from the health costs of fossil fuel use and CO_2 emissions increase average power generation costs by at least USD 0.01/kWh for countries with electricity generation systems that are relatively less carbon-intensive and up to USD 0.13/kWh for systems that are carbon-intensive (IRENA, 2014). This increases costs for fossil fuels from a range of USD 0.045 to USD 0.14/kWh a range of USD 0.07 to 0.19/kWh, given that the lowest values without external costs are some of the most polluting technologies.

Figure 2.12 presents the LCOE by project ranges for the VRE technologies solar PV and wind onshore compared to fossil fuel-fired electricity generation costs. It also then presents the LCOE for solar PV and wind onshore including VRE costs assumptions for 40% VRE of USD 0.035 to USD 0.05/kWh and the fossil fuel-fired cost range including the external health and climate change costs of their use. When the local and global environmental costs of fossil fuels are taken into account, grid integration costs look considerably less daunting, even with variable renewable sources providing 40% of the power supply. In other words, with a level playing field and all externalities considered, renewables are fundamentally competitive. Accounting for the very real external costs that fossil fuels currently don't pay for demonstrates why renewables need support to level the playing field. When externalities are taken into account, renewables are virtually always the cheapest option for society.

3 GLOBAL RENEWABLE POWER MARKET TRENDS

The year 2013 was a landmark year for renewables. In 2013, despite inconsistent policymaking and weak economic growth, overall capacity additions reached a new record high of more than 120 gigawatts (GW), with new solar deployment exceeding wind for the first time. Figures for 2014 are still not finalised, but new capacity additions for both solar photovoltaic (PV) and wind are estimated to have exceeded 40 GW each.

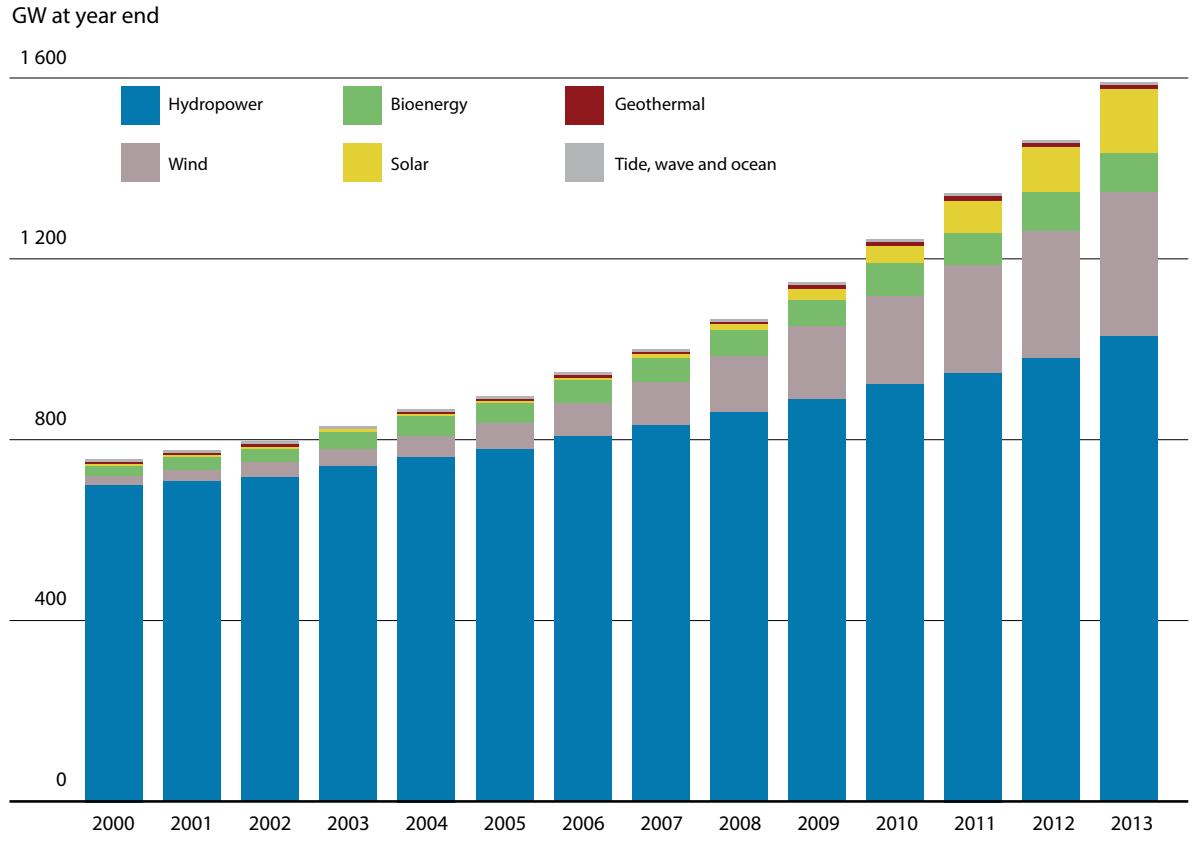
Renewable energy markets are increasingly deeper and broader than in the past and fluctuations in one market in recent years have often compensated movements in others. Improving cost competitiveness continues to drive the deployment of both wind and solar technologies and lies behind this maturing of renewable markets.

However, markets for renewable power generation technologies are still too narrow, relative to their economic potential. New and deeper markets need to be unlocked if the world is to shift to a truly sustainable power generation sector before dangerous climate change becomes inevitable.

Cumulative installed renewable power generation capacity at the end of 2013

At the end of 2013, renewable power generation capacity had risen to around 1 560 to 1 580 GW, excluding pumped storage hydro. Although hydropower still dominates this total, the rapid growth in wind and solar PV means that hydro's share is slowly declining. However,

Figure 3.1: Global cumulative installed renewable power generation capacity, 2000 to 2013



Source: IRENA

the rate of decline is slower for hydro's share of renewable power generation than for its capacity, as the capacity factors of wind and solar PV are on average lower than hydropower.

Hydropower capacity, excluding pumped storage (all hydropower data in this chapter exclude pumped storage unless specifically stated) reached around 1 025 GW at the end of 2013 – representing approximately two-thirds of all renewable power generation capacity – after strong growth in new capacity added in 2013 (Figure 3.1). Hydropower accounted for around 16% of the world's electricity and around 75% of the world's renewable electricity in 2013. Pumped storage hydro capacity now stands at somewhere between 135 and 157 GW, of which approximately 25 GW have been identified as mixed plants that are also conventional resevoir-based hydropower dams (GlobalData, 2014 and REN21, 2014).

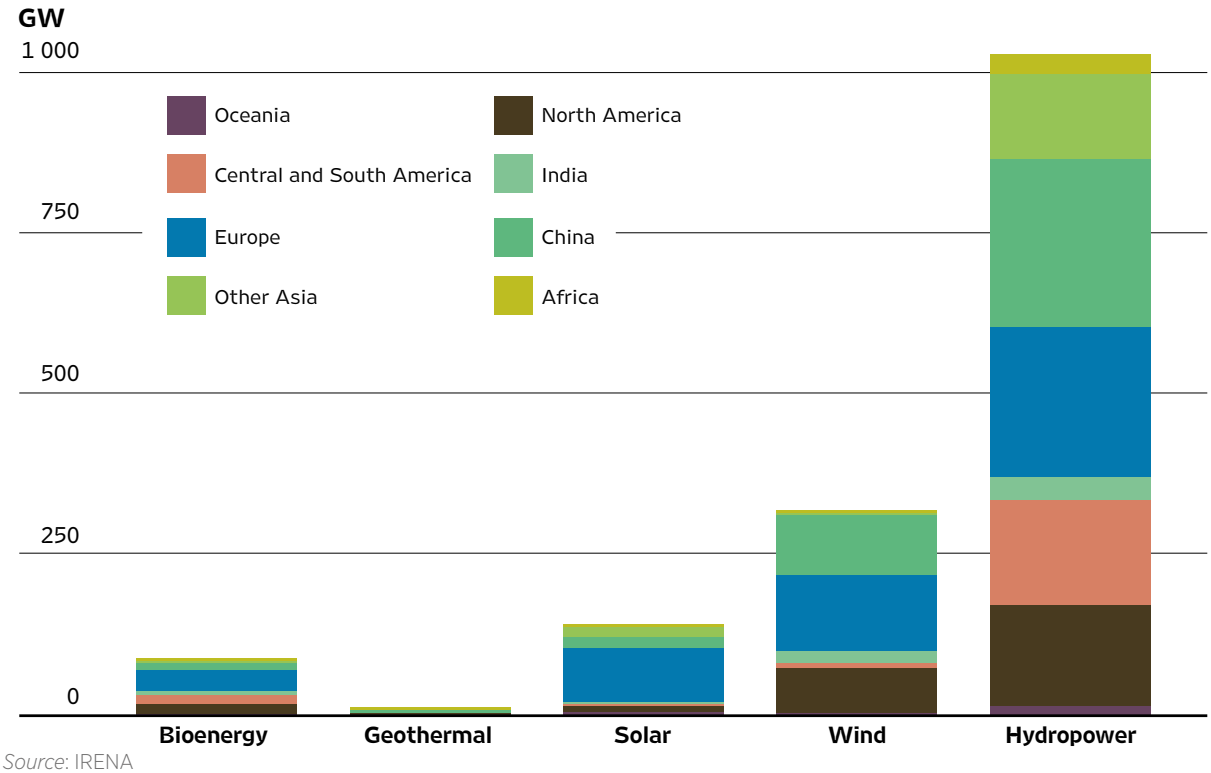
China, Brazil, the United States, Canada, the Russian Federation and India have the largest hydropower generation capacity. China accounts for just over one-quarter of global installed hydropower capacity, Europe for 23%, Central and South America for 16%, North America for 15% and Asia, excluding China, for 13%.

The installed capacity of non-hydro renewables reached around 560 GW at the end of 2013, with wind accounting for 318 GW (20% of the total, of which offshore wind provided 7 GW), solar PV accounting for 139 GW, biomass power generation capacity for 87 GW, geothermal for 12 GW and concentrating solar power (CSP) for 3.4 GW.

Globally, Europe accounted for 30% (473 GW) of total installed renewable power generation capacity at the end of 2013. China, with 377 GW installed at the end of 2013, accounted for 24%, while North America accounted for 16%, with 258 GW of installed renewable capacity (Figure 3.2).

At the end of 2013, Europe had the largest installed capacity of biomass for power generation (35 GW), solar PV (80 GW), onshore wind (112 GW) and CSP (2.3 GW). "Other Asia" (excluding China and India) accounts for the largest share of geothermal installed capacity (4 GW), with North America accounting for the next largest share (3.4 GW). Europe and Other Asia each account for around 250 MW of the global tidal, wave and ocean energy

FIGURE 3.2: GLOBAL CUMULATIVE INSTALLED RENEWABLE POWER GENERATION CAPACITY BY TECHNOLOGY AND COUNTRY/REGION, 2013



Source: IRENA

Table 3.1: Top five countries for cumulative installed renewable power generation capacity by technology, 2013

Biomass for power		Geothermal		Hydropower		Offshore Wind	
United States of America	12.7	United States of America	3.4	China	258.5	United Kingdom	3.7
Brazil	11.5	Philippines	1.9	Brazil	86.0	Denmark	1.3
China	8.5	Indonesia	1.3	United States of America	82.8	Germany	0.9
Germany	8.2	New Zealand	0.9	Canada	75.5	Belgium	0.6
India	4.7	Mexico	0.8	Russian Federation	49.0	China	0.4

Onshore Wind		Solar Photovoltaic		Solar CSP		Tide, Wave & Ocean	
China	91.0	Germany	36.3	Spain	2.3	Republic of Korea	0.3
United States of America	60.2	China	18.6	United States of America	0.9	France	0.2
Germany	33.8	Italy	17.9	United Arab Emirates	0.1	Canada	0.0
Spain	23.0	Japan	13.6	India	0.1	United Kingdom	0.0
India	20.2	United States of America	12.1	Algeria	0.0	China	0.0

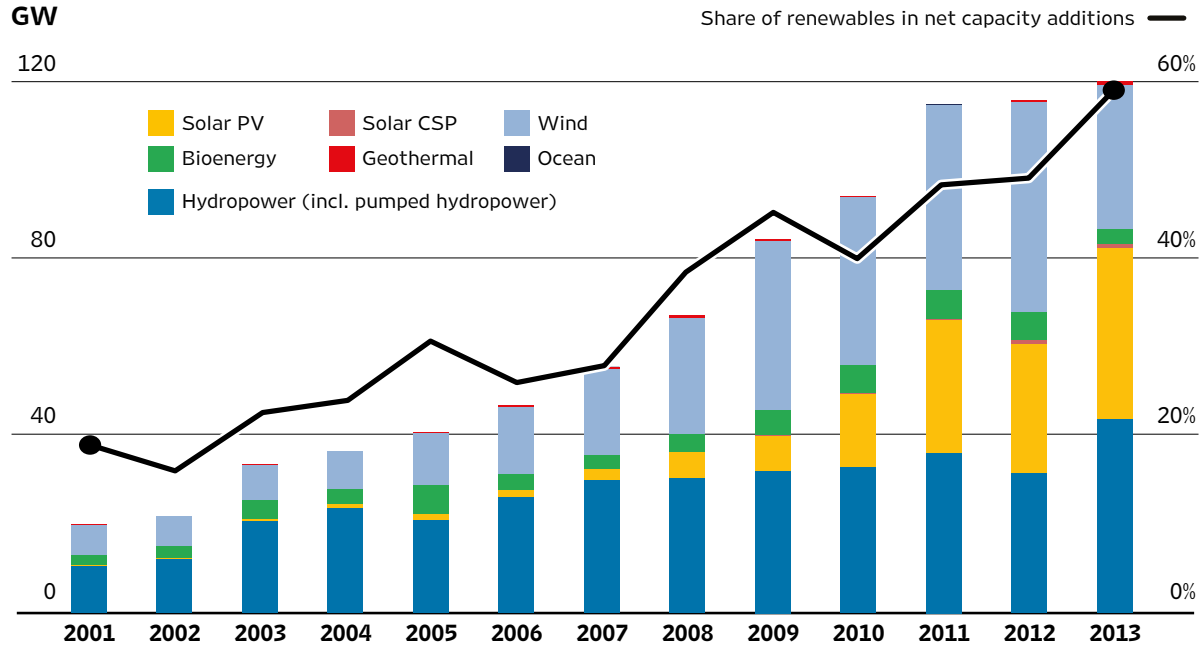
capacity. This capacity stood at around 526 MW at the end of 2013, virtually all of that capacity being tidal.

Despite the fact that policy uncertainty in 2013 affected a number of wind markets, notably the United States, wind capacity rose to around 318 GW at the end of 2013, with 7.4 GW of this capacity being offshore. After hydropower, wind capacity is the next largest renewable contribution to global installed power generation capacity. China has the world's largest installed onshore wind capacity for a single country and at around 91 GW accounts for 29% of global installed capacity. This has been driven by new capacity additions of between 13 GW and around 18 GW per year since 2009. The traditional drivers of wind deployment in Europe and the United States account for second through fourth place for onshore wind, while the rapidly growing markets in India mean that it now has the fifth largest global installed capacity of wind. Offshore wind capacity is dominated by the United Kingdom, which has half of the world's total installed capacity.

Solar PV, with 139 GW of installed capacity at the end of 2013, is the third largest source of renewable power generation capacity. Germany, the pioneer in solar PV deployment, retained the largest share of global capacity (27%), but based on current trends it will be rapidly overtaken by China, which had the second largest capacity – of 18.6 GW – installed by the end of 2013. Italy, Japan and the United States round out the top five countries with respect to solar PV deployment. Of these three, Japan and the United States have the most dynamic markets and Japan will soon overtake Italy for third place.

CSP deployment is still at a very early commercial stage and total installed capacity at the end of 2013 was around 3.4 GW, with around two-thirds of this capacity located in Spain and approximately another quarter in the United States. Spain and the United States will remain the largest sources of CSP capacity in the near future, despite growing deployment in coming years in a number of countries, including, but not limited to, India and South Africa in particular. With strong capacity additions in 2014, the total installed deployment of CSP at the end of 2014 is estimated to have reached 5 GW.

FIGURE 3.3: ANNUAL NEW RENEWABLE POWER GENERATION CAPACITY ADDITIONS BY TECHNOLOGY INCLUDING PUMPED STORAGE, 2001 TO 2013



Source: IRENA and GlobalData, 2014

Globally, the distribution of biomass for power generation is not as concentrated as wind or solar, with the top five countries accounting for just over half of total installed capacity at the end of 2013. The United States (15%), Brazil (13%), China (10%), Germany (9%) and India (5%) have the largest concentrations of biomass for power generation. Geothermal capacity is concentrated in a few countries as well. The United States (29%), the Philippines (16%), Indonesia (11%), New Zealand (8%) and Mexico (7%) have the largest installed capacity of geothermal power generation. Tidal, wave and ocean energy make only a small contribution to global power generation capacity today, with virtually all capacity concentrated in tidal projects in France and the Republic of Korea.

ANNUAL NEW RENEWABLE POWER GENERATION CAPACITY ADDITIONS BY YEAR

The years 2013 and 2014 have seen record growth in renewable power generation capacity. In 2013 new renewable capacity additions reached a new record of at least 120 GW, with strong growth from hydropower and solar PV more than offsetting a small decline in new wind capacity additions. Solar PV deployment grew to around 39 GW for the year, led by strong growth in China and Japan in particular.[14] Hydropower was also estimated to have had a strong year, with between 40 and 48 GW of new capacity added (IRENA and GlobalData, 2014).[15]

New wind deployment was slightly lower in 2013 than in 2012 at 35.5 GW, as policy uncertainty delayed projects, notably in the United States (GWEC, 2014 and WWEA, 2014). However, wind is expected to bounce back, and 2014 looks likely to be another year where wind deployment exceeds 40 GW.

With firmer policy support, new solar PV installations look set to have exceeded 40 GW in 2014, with some estimates closer to 50 GW in 2014 (BNEF, 2014; IRENA analysis and Photon Consulting, 2014).

[14] Some uncertainty still exists about the exact total; although data are available for most major markets, total deployment estimates vary between 37 GW and 39 GW (EPIA, 2014; BNEF, 2014 and Photon Consulting, 2014).

[15] This exceeds early estimates of around 40 GW added in 2013 (REN21, 2014). However, some uncertainty remains about net capacity additions for hydropower in 2013 due to the time lags in full reporting of net capacity changes for the large number of existing dams. There are over 5 800 dams over 15 m in height used for hydropower worldwide (International Commission on Large Dams, 2014) and 65 000 small hydropower installations in China alone (UNIDO and ICSHP, 2014), making timely collation and reporting of data difficult.

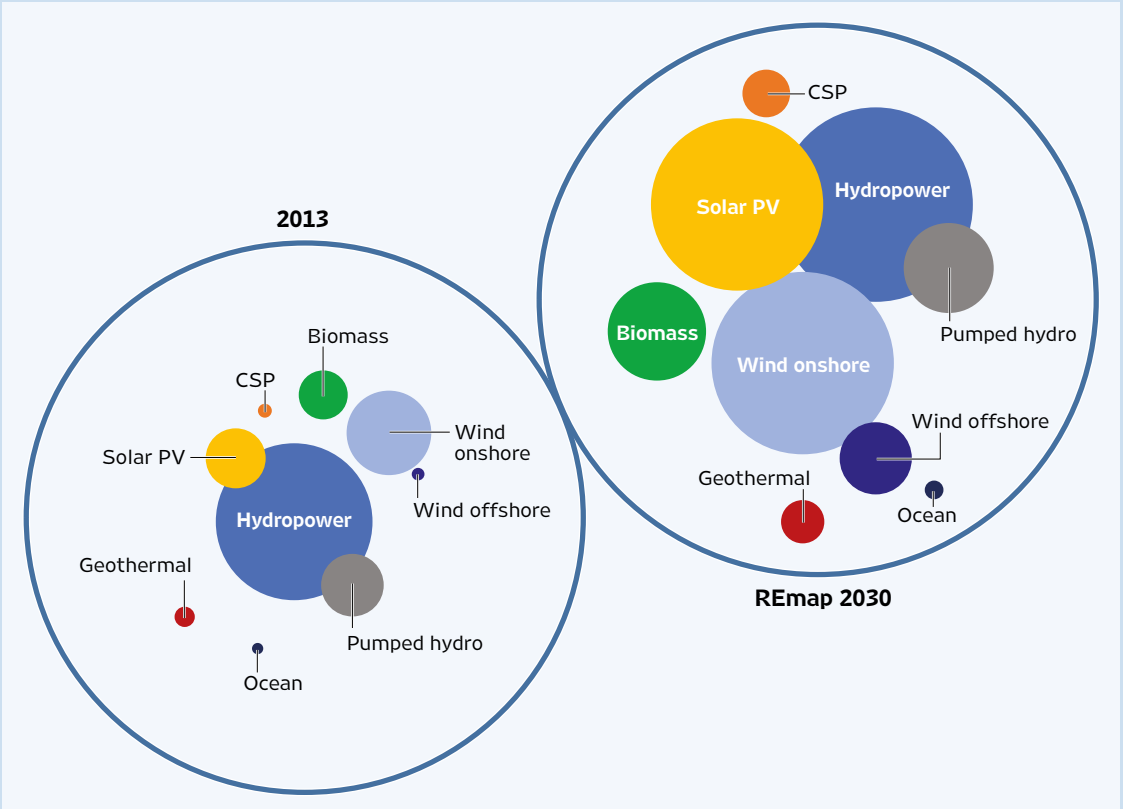
BOX 3.1

What the future holds: Renewable power generation in 2030 in IRENA's REmap analysis

IRENA's REmap analysis, which examines how to double the share of renewables by 2030, highlights just how rapidly the power sector landscape is changing (IRENA, 2014). At the end of 2013, hydropower dominated total cumulative installed renewable capacity, with around 1 025 GW of capacity (Figure 3.2). Wind power contributed around 318 GW and solar PV capacity reached around 139 GW of cumulative installed capacity.

To double the share of renewables, although hydropower will grow to 1 600 GW in 2030 in the REmap 2030 case, wind capacity growth is so rapid that wind power capacity will exceed hydropower by 2030, with 1 630 GW of installed capacity and 231 GW of that total offshore. Solar PV growth will exceed that of wind, but from a lower base, to reach 1 250 GW in 2030, with CSP growing to 83 GW in 2030 in the REMAP scenario. With significantly more untapped economic potential than hydropower, wind and solar will continue to outpace hydropower growth and grow in importance in terms of installed capacity and, in the case of wind, electricity generation as well.

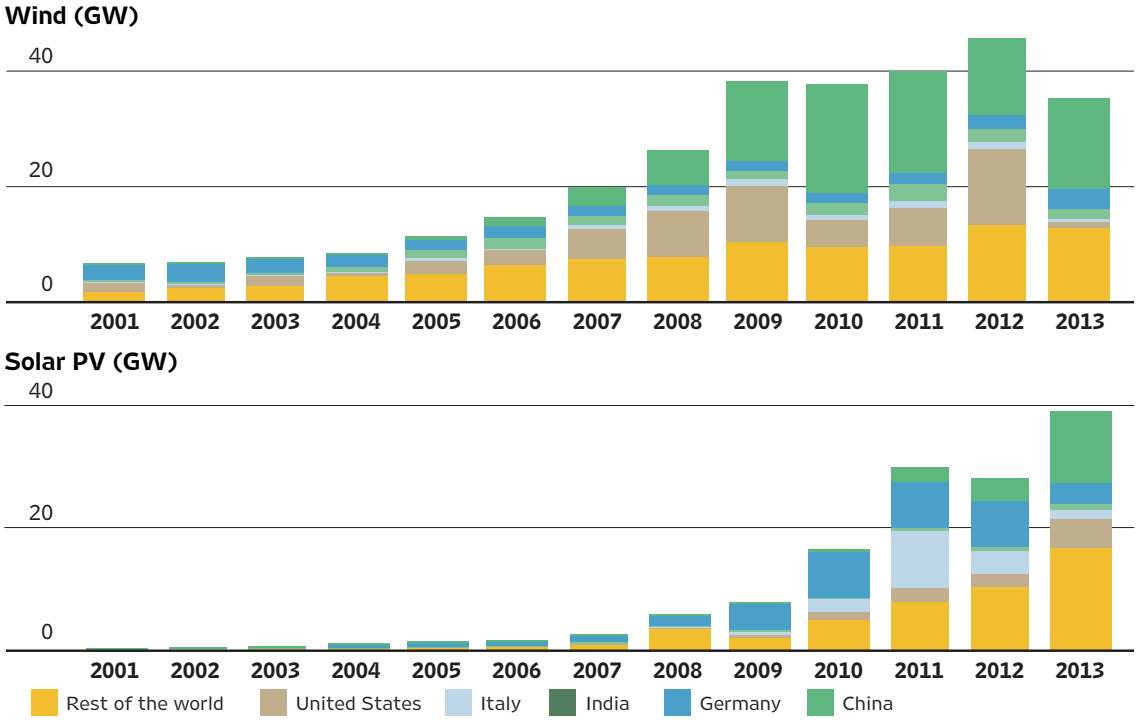
Figure 3.4: Total cumulative installed renewable capacity, 2013 and REMAP 2030



Source: IRENA statistics and IRENA, 2014

Renewable energy capacity additions have risen six-fold between 2001 and 2013, and have accounted for around half of all new power generation capacity added each year from 2011 to 2013. New renewable capacity additions have been around 100 GW per year or more since 2010. In that time, annual new solar PV capacity additions have grown from insignificant levels to around 39 GW in 2013, representing around one-third of new renewable capacity additions and 19% of all new capacity additions in 2013 globally.

Figure 3.5: Annual new capacity additions for wind and solar PV, 2001 to 2013



Source: IRENA

New annual wind power capacity additions grew by around 450% between 2001 and 2013, from 6.5 GW to 35.5 GW, and with projections for 2014 of at least 40 GW (BNEF, 2014; WWEA, 2014 and IRENA analysis) new wind power additions could be up to six or seven times higher in 2014 than in 2001. In 2013, new wind capacity additions constituted 27% of total renewable additions and 17% of total new capacity additions worldwide.

In 2013, China added the most new capacity for hydropower (30 GW), onshore wind (16 GW) and solar PV (13 GW). China's support for solar PV since 2011 has spurred growth in domestic solar PV deployment and China is now the leading country for new capacity additions of renewable power generation technologies. In 2013, China is estimated to have accounted for as much as 45% of total new capacity additions of renewable power generation technologies worldwide.

The global wind power market was essentially flat in 2009 and 2010 as high wind turbine prices and economic uncertainty slowed growth. 2011 and 2012 saw new capacity additions of 40 GW and 45 GW, respectively. New installed capacity dropped in 2013 to 35.5 GW of new capacity added, due in large part to a rush to add new capacity in 2012 in the United States before the scheduled expiry of the production tax credit for wind in that country. New capacity additions dropped to just 1.3 GW in 2013 in the United States, a similar experience to what was seen in 2009/2010 due to the same circumstances, but on a more extreme scale.

In 2013 this meant the United States dropped out of the top five countries for newly installed capacity additions (Figure 3.5 and Table 3.2). China accounted for 44% of global wind power installations in 2013, installing 16 GW. In 2013, the European market added around 12 GW of new capacity, down from 12.4 in 2012. Most drastic was the reduction in new installations for North America, which went from 14.3 GW in 2012 to 2.7 GW in 2013 due to the decline in new capacity additions in the United States.

Onshore wind still dominates new capacity additions for total wind and accounted for around 98% of all new wind capacity in 2013. However, the offshore wind market is growing rapidly, with around 1.9 GW added in 2013. The total global installed capacity of offshore wind reached 7.4 GW at the end of 2013 and with an estimated 1.2 GW added in 2014 may have reached 8.5 GW by the end of 2014.

BOX 3.2

Cumulative installed capacity and new capacity additions in 2013 per capita

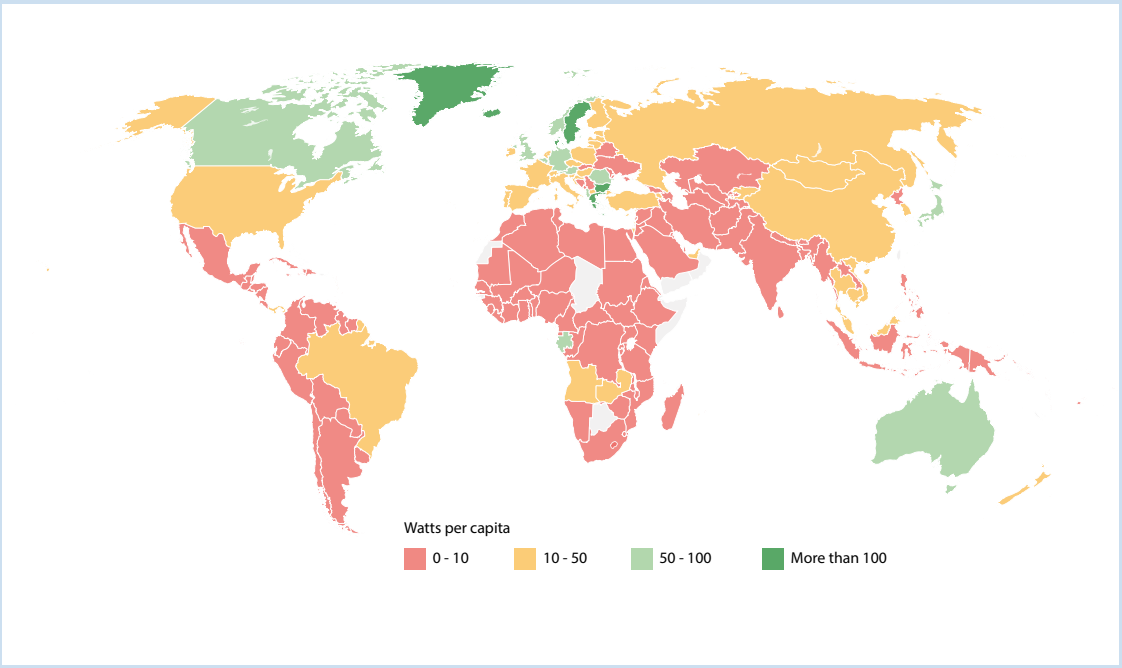
An alternative method of looking at both new capacity additions and total cumulative installed capacity of renewable power generation technologies is to examine their per capita values by country. This yields a significantly different view of the leading countries in terms of renewables deployment.

Using these metrics, Iceland emerges as a renewable energy powerhouse, with 8.2 MW of renewable electricity per 1 000 inhabitants, having added 341 kW per 1 000 inhabitants of new renewable power generation capacity in 2013 (Figure 3.6).

Norway, Sweden, Canada and Austria all also have more than 2 MW of renewable capacity per 1 000 inhabitants. For cumulative installed capacity per capita in all of these top five countries, it is their large hydropower resources relative to modest populations which set them apart. However, even excluding hydropower from these calculations, Iceland remains the leading country per capita due to that country's geothermal developments, while Sweden only drops from third to fourth place due to its significant wind and biomass for power deployment. What is interesting, but not surprising, is that Denmark, Germany and Spain appear in places two, three and five.

In terms of newly installed capacity per capita in 2013, Iceland is followed by Bulgaria (170 kW/per capita), Denmark (139 kW/per capita), Greece (111 kW/per capita) and Sweden (105 kW/per capita).

Figure 3.6: Annual new capacity additions of renewable power per capita, 2013



Source: IRENA and World Bank, 2014

Table 3.2: Top five countries for new installed renewable power generation capacity by technology, 2013

Biomass for power		Geothermal		Hydropower		Offshore Wind	
Brazil	1.5	Turkey	0.1	China	29.9	United Kingdom	0.7
United Kingdom	0.7	New Zealand	0.1	Turkey	2.7	Germany	0.6
Germany	0.6	United States of America	0.1	Vietnam	2.4	Denmark	0.3
China	0.5	Kenya	0.0	France	1.8	Belgium	0.2
Italy	0.5	Philippines	0.0	Brazil	1.7	Sweden	0.0

Onshore Wind		Solar Photovoltaic		Solar Thermal	
China	15.7	China	12.9	Spain	0.3
Germany	2.8	Japan	2.8	United States of America	0.4
India	1.7	United States of America	1.7	United Arab Emirates	0.1
United Kingdom	1.6	Germany	1.6	India	0.1
Canada	1.6	Australia	1.6	Algeria	0.0

Source: IRENA

New solar PV capacity soared in 2013 to around 39 GW as markets in China, Japan and the United States showed strong growth. 2013 represented a seismic shift in new solar PV capacity deployment, as leadership for deployment shifted from Europe to the Asia-Pacific region. China, Japan, the United States and Australia together accounted for around two-thirds of new capacity additions in 2013 (Table 3.2). This stands in contrast to 2012, when Europe added around 59% of total new capacity. With the German and Italian new capacity additions expected to be lower again in 2014 than in 2013, the trend towards market growth being driven by the Asia-Pacific region will be confirmed in 2014.

Newly installed CSP capacity in 2013 totaled around 0.9 GW, with the United States, Spain, the United Arab Emirates and India adding the most new capacity. The outlook for CSP remains delicate as the regulatory environment in Spain, a major driver of growth in recent years, is currently significantly less favourable than in previous years. Growth will diversify somewhat, but most growth will come from the United States in the next few years as significant new capacity is either committed or planned.

New capacity additions of biomass for power generation were slightly lower, at 5.5 GW, in 2013 than in 2012. Brazil, the United Kingdom, Germany, China and Italy led the way in 2013, adding a combined total of 3.7 GW, or around two-thirds of the total for 2013.