IRENA
International Renewable Energy Agency

# RENEWABLE POWER GENERATION COSTS IN 2020

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## About IRENA

The International Renewable Energy Agency (IRENA) serves as the principal platform for international co-operation, a centre of excellence, a repository of policy, technology, resource and financial knowledge, and a driver of action on the ground to advance the transformation of the global energy system. An intergovernmental organisation established in 2011, IRENA promotes the widespread adoption and sustainable use of all forms of renewable energy, including bioenergy, geothermal, hydropower, ocean, solar and wind energy, in the pursuit of sustainable development, energy access, energy security and low-carbon economic growth and prosperity. **www.irena.org**

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# FOREWORD

**Francesco La Camera**

*Director-General*
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Renewables are becoming more and more competitive in the energy landscape. The data from the IRENA Renewable Cost Database shows cost declines continued in 2020, with the cost of electricity from utility-scale solar photovoltaics (PV) falling 7% year-on-year, offshore wind fell by 9%, onshore wind by 13% and that of concentrating solar power (CSP) by 16%.

The decade 2010 to 2020 saw dramatic improvement in the competitiveness of solar and wind power technologies. Between 2010 and 2020, the cost of electricity from utility-scale solar photovoltaics (PV) fell 85%, followed by concentrating solar power (CSP; 68%), onshore wind (56%) and offshore wind (48%). The last decade has seen CSP, offshore wind and utility-scale solar PV all join onshore wind in the cost range for new capacity fired by fossil fuels, when calculated without the benefit of financial support. Indeed, the trend is not only one of renewables competing with fossil fuels, but significantly undercutting them.

This is not just the case where new generating capacity is required. The analysis in this report shines a spotlight on how even existing coal plants are increasingly vulnerable to being undercut by new renewables. Indeed, our analysis suggests that up to 800 gigawatts (GW) of existing coal-fired capacity could be economically replaced by new renewables capacity, saving the electricity system up to USD 32 billion per year and reducing carbon-dioxide ($CO_2$) emissions by up to 3 gigatonnes (Gt) $CO_2$. This would provide 20% of the emissions reduction needed by 2030 for the 1.5°C climate pathway outlined in IRENA's *World Energy Transitions Outlook*. There is no room for these coal assets to be part of the energy future, retrofitting with carbon capture and storage would only increase costs. While the flexibility to integrate very high shares of renewables will come from other, cheaper sources, with IRENA having identified 30 options that can be combined into comprehensive solutions in the report *Innovation landscape for a renewable powered future*.

IRENA has, for over a decade, highlighted the essential role renewable power generation will play in the energy transition, as the opportunities for cost reduction were time and again, demonstrated, and then, in many cases, exceeded as smart policy and the razor-sharp focus of industry combined to unlock better performance and lower costs. The insights from IRENA's data bear witness to the fruits of IRENA's pluriannual programme of work and its focus on providing our Member States with the facts they need to support the energy transition at home. With falling renewable power generation costs, updates to Nationally Determined Contributions (NDC) need to consider the opportunities that have emerged in recent years. Countries can be more ambitious, and IRENA is ready to support them in that process.

This report also reinforces one of the key messages of our *World Energy Transitions Outlook 2021*, that very low-cost renewables can not only form the backbone of a decarbonised electricity system, but support a radically different future energy system where renewable hydrogen – derived from very low-cost renewable electricity – and modern biomass provide the last key to unlocking an affordable pathway to a 1.5°C future for us all. Now is the time to seize that opportunity.

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# ABBREVIATIONS

| | |
|---|---|
| **BoS** | Balance of System |
| **CAPEX** | Capital expenditure |
| **CCUS** | carbon capture, utilisation and storage |
| **CIF** | Climate Investment Fund |
| **$CO_2$** | carbon dioxide |
| **CSP** | concentrated solar power |
| **EU** | European Union |
| **EUR** | euro |
| **FIT** | feed-in tariff |
| **GW** | gigawatt |
| **HTF** | Heat Transfer Fluid |
| **ILR** | Inverter Load Ratio |
| **IPP** | independent power producer |
| **IRENA** | International Renewable Energy Agency |
| **ITC** | Investment Tax Credit |
| **kW** | kilowatt |
| **kWh** | kilowatt-hour |
| **LCOE** | Levelised cost of electricity |
| **$LCOH_2$** | Levelised cost of hydrogen |
| **LCOHEAT** | Levelised cost of heat |
| **Mtoe** | million tonnes of oil equivalent |
| **MW** | megawatt |
| **MWh** | megawatt-hour |
| **NDC** | Nationally Determined Contributions |
| **NREL** | National Renewable Energy Laboratory (US) |
| **O&M** | Operation and Maintenance |
| **OECD** | OECD Organisation of Economic Co-operation and Development |
| **OEM** | Original Equipment Manufacturer |
| **PPA** | Power Purchase Agreement |
| **PTC** | Parabolic trough Collectors |
| **TWh** | Terawatt-hour |
| **WACC** | Weighted Average Cost of Capital |

# HIGHLIGHTS

- The trend in cost declines continued for solar and wind power in 2020, despite the impact of the global pandemic and the disruptions caused by the spread of COVID-19 virus. In 2020, the global weighted-average levelised cost of electricity (LCOE) from new capacity additions of onshore wind declined by 13%, compared to 2019. Over the same period, the LCOE of concentrating solar power (CSP) fell by 16%, that of offshore wind fell by 9% and that of utility-scale solar photovoltaics (PV) by 7%.
- Renewable power generation costs have fallen sharply over the past decade, driven by steadily improving technologies, economies of scale, competitive supply chains and improving developer experience. Costs for electricity from utility-scale solar PV fell 85% between 2010 and 2020.
- The cost of electricity from solar and wind power has fallen, to very low levels. Since 2010, globally, a cumulative total of 644 GW of renewable power generation capacity has been added with estimated costs that have been lower than the cheapest fossil fuel-fired option in each respective year. In emerging economies, the 534 GW added at costs lower than fossil fuels, will reduce electricity generation costs by up to USD 32 billion this year.
- New solar and wind projects are increasingly undercutting even the cheapest and least sustainable of existing coal-fired power plants. IRENA analysis suggests 800 GW of existing coal-fired capacity has operating costs higher than new utility-scale solar PV and onshore wind, including USD 0.005/kWh for integration costs. Replacing these coal-fired plants would cut annual system costs by USD 32 billion per year and reduce annual $CO_2$ emissions by around 3 Gigatonnes of $CO_2$.
- This comprehensive cost study draws on cost and auction price data from projects around the world and highlights the latest trends for each of the main renewable power technologies.

**Table H1** Total installed cost, capacity factor and levelised cost of electricity trends by technology, 2010 and 2020

| | Total installed costs (2020 USD/kW) | | | Capacity factor (%) | | | Levelised cost of electricity (2020 USD/kWh) | | |
|---|---|---|---|---|---|---|---|---|---|
| | 2010 | 2020 | Percent change | 2010 | 2020 | Percent change | 2010 | 2020 | Percent change |
| Bioenergy | 2 619 | 2 543 | -3% | 72 | 70 | -2% | 0.076 | 0.076 | 0% |
| Geothermal | 2 620 | 4 468 | 71% | 87 | 83 | -5% | 0.049 | 0.071 | 45% |
| Hydropower | 1 269 | 1 870 | 47% | 44 | 46 | 4% | 0.038 | 0.044 | 18% |
| Solar PV | 4 731 | 883 | -81% | 14 | 16 | 17% | 0.381 | 0.057 | -85% |
| CSP | 9 095 | 4 581 | -50% | 30 | 42 | 40% | 0.340 | 0.108 | -68% |
| Onshore wind | 1 971 | 1 355 | -31% | 27 | 36 | 31% | 0.089 | 0.039 | -56% |
| Offshore wind | 4 706 | 3 185 | -32% | 38 | 40 | 6% | 0.162 | 0.084 | -48% |

# EXECUTIVE SUMMARY

## RENEWABLE POWER GENERATION COSTS IN 2020

The year 2020 was marked by the global pandemic and the subsequent economic and human toll it took as the COVID-19 virus spread. One bright spot, however, was the resilience of renewable power generation supply chains and record growth in new deployment.

There was no disruption to the trend in continued cost declines for solar and wind power, either. In 2020, the global weighted-average levelised cost of electricity (LCOE) from new capacity additions of onshore wind declined by 13%, compared to 2019. Over the same period, the LCOE of offshore wind fell by 9% and that of utility-scale solar photovoltaics (PV) by 7% (Figure ES1).

That 13% year-on-year fall in the global weighted-average onshore wind LCOE, from USD 0.045/kilowatt hour (kWh) to USD 0.039/kWh,[1] was slightly higher than the rate of decline in 2019. The decline was driven by a 9% fall in the global weighted-average total installed cost, as China – which has lower than average installed costs – connected an estimated 69 GW to the grid in 2020, two-thirds of the new capacity deployed that year.

In 2020, the 7% year-on-year decline in the LCOE of utility-scale solar PV, from USD 0.061/kWh to USD 0.057/kWh, was lower than the 13% decline experienced in 2019. In 2020, too, the global weighted-average total installed cost of utility-scale solar PV fell by 12%, to just USD 883/kW.

The decline in LCOE terms for utility-scale solar PV was lower than it otherwise might have been, as the decline in total installed costs experienced was partially offset by a reduction in the global weighted-average capacity factor of new projects in that year.[2] This was driven by deployment in 2020 that was, on balance, weighted towards areas with poorer solar resources than those seeing deployment in 2019.[3] Similar to the situation for onshore wind, China was the largest market for new capacity, accounting for an estimated 45% of the new, utility-scale capacity added in 2020.

1 *All financial values presented in this report are real, 2020 values - that is to say, they are adjusted for the impact of inflation on a 2020 base year. LCOE calculations are made based on the methodology detailed in Annex I and exclude the impact of any financial support available.*

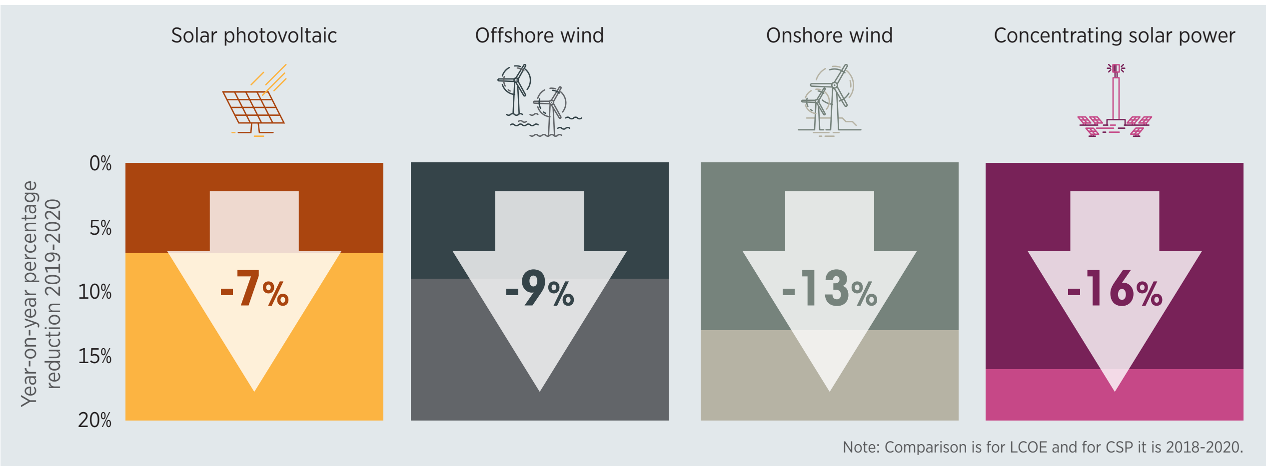
2 *All solar PV capacity factors quoted in this report are alternating current (AC)/direct current (DC) capacity factors, given all installed cost data for solar PV is quoted per-watt of direct current, which is an exception, as all other technologies are report in AC terms.*

3 *This result should be treated with caution, given the increasing importance of bifacial modules and single-axis trackers, where data availability lags total installed cost and has a material impact on capacity factors. Revisions to the 2020 capacity factor are possible.*

The 9% year-on-year decline in the global weighted-average LCOE of offshore wind in 2020 saw the global weighted-average cost of electricity of new projects fall from USD 0.093/kWh to USD 0.084/kWh. This was a sharper decline than that experienced in 2019, as China – which has lower than average installed costs – increased its share of new capacity additions, from around one third in 2019 to around half in 2020.

The global weighted-average LCOE of new, concentrating solar power (CSP) projects commissioned in 2020 fell by 49%, year-on-year. This result is somewhat atypical, however, as the global weighted-average LCOE in 2019 was pushed up by two much delayed Israeli projects, while 2020 was characterised by the commissioning of just two plants, both in China. Looking at the figures between 2018 and 2020 reveals a compound annual rate of decline of 16% per year, which is more representative of recent rates of cost reduction.

**Figure ES.1** Global weighted-average LCOE from newly commissioned, utility-scale solar and wind power technologies, 2019-2020




*Source: IRENA Renewable Cost Database*

## RENEWABLE POWER GENERATION COST TRENDS, 2010-2020: A DECADE OF FALLING COSTS

The decade 2010 to 2020 represents a remarkable period of cost reduction for solar and wind power technologies. The combination of targeted policy support and industry drive has seen renewable electricity from solar and wind power go from an expensive niche, to head-to-head competition with fossil fuels for new capacity. In the process, it has become clear that renewables will become the backbone of the electricity system and help decarbonise electricity generation, with costs lower than a business-as-usual future.

The global weighted-average LCOE of utility-scale solar PV for newly commissioned projects fell by 85% between 2010 and 2020, from USD 0.381/kWh to USD 0.057/kWh (Figure ES.2), as total installed costs fell from USD 4 731/kW to USD 883/kW. This occurred as global cumulative installed capacity of all solar PV (utility scale and rooftop) increased from 42 GW in 2010 to 714 GW in 2020. This represented a precipitous decline, from being more than twice as costly as the most expensive fossil fuel-fired power generation option to being at the bottom of the range for new fossil fuel-fired capacity.[4]

The LCOE of residential PV systems also declined steeply over the period. The LCOE of residential PV systems in Australia, Germany, Italy, Japan and the United States declined from between USD 0.304/kWh and USD 0.460/kWh in 2010 to between USD 0.055/kWh and USD 0.236/kWh in 2020 – a decline of between 49% and 82%.

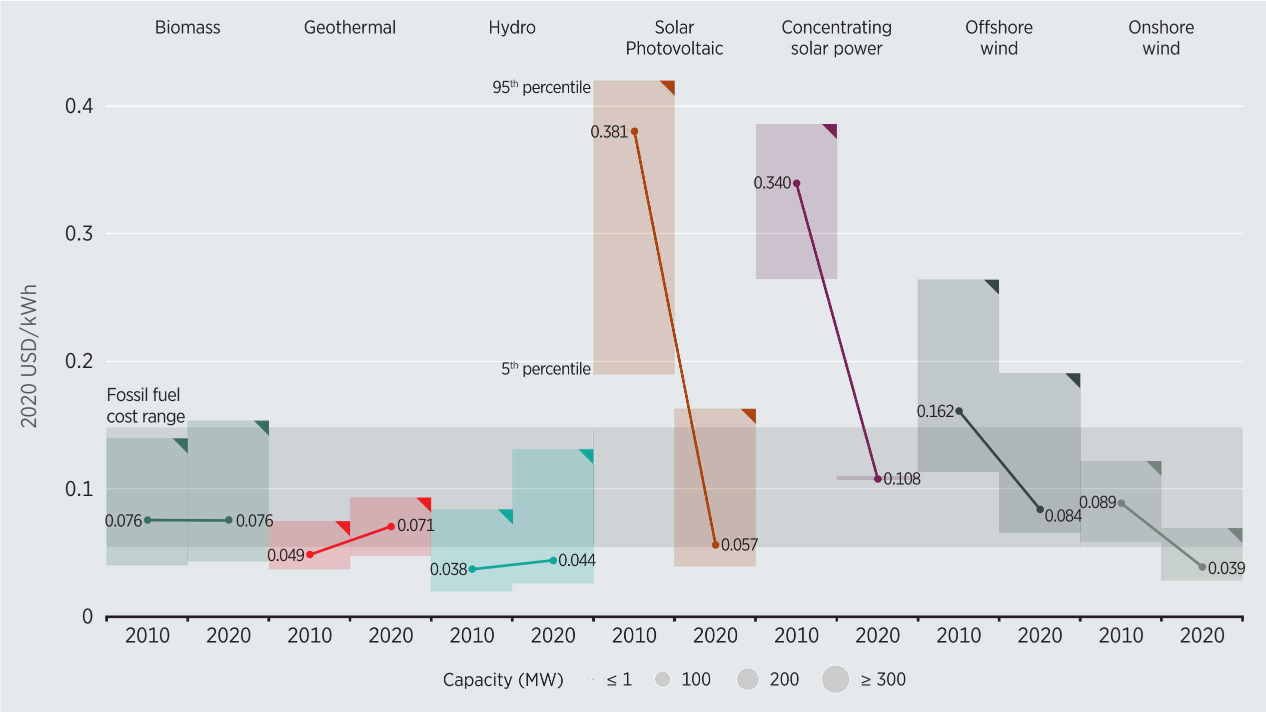
For onshore wind projects, the global weighted-average cost of electricity between 2010 and 2020 fell by 56%, from USD 0.089/kWh to USD 0.039/kWh, as average capacity factors rose from 27% to 36% and total installed costs declined from USD 1 971/kW to USD 1 355/kW. Cumulative installed capacity grew from 178 GW to 699 GW during this period. Compared to solar PV, where electricity cost declines are mainly driven by falling total installed costs, onshore wind cost reductions were driven more evenly by both falls in turbine prices and balance of plant costs, and higher capacity factors from today's state-of-the-art turbines.

For offshore wind, the global weighted-average LCOE of newly commissioned projects declined from USD 0.162/kWh in 2010 to USD 0.084/kWh in 2020, a reduction of 48% in 10 years. This has transformed the outlook for offshore wind, with cumulative installed capacity of offshore wind at just 34 GW at the end of 2020, which is around one-twentieth of that of onshore wind.

Over the period 2010 to 2020, the global weighted-average cost of electricity from CSP fell 68% from USD 0.340/kWh to USD 0.108/kWh. With just two projects commissioned in 2020 – both in China – these results, however, reflect the national circumstances of that country. Having said that, the 68% decline in the cost of electricity from CSP – into the middle of the range of the cost of new capacity from fossil fuels – remains a remarkable achievement. For comparison, the global cumulative installed capacity for CSP of 6.5 GW at the end of 2020 was slightly less than a hundredth of the capacity of solar PV installed.

*4 The fossil fuel-fired power generation cost range for the G20 group by country and fuel type is estimated to be between USD 0.055/kWh and USD 0.148/kWh. The lower bound represents new, coal-fired plants in China and is based on IEA, 2020.*

**Figure ES.2** Global LCOEs from newly commissioned, utility-scale renewable power generation technologies, 2010-2020




*Source: IRENA Renewable Cost Database*

*Note: This data is for the year of commissioning. The thick lines are the global weighted-average LCOE value derived from the individual plants commissioned in each year. The project-level LCOE is calculated with a real weighted average cost of capital (WACC) of 7.5% for OECD countries and China in 2010, declining to 5% in 2020; and 10% in 2010 for the rest of the world, declining to 7.5% in 2020. The single band represents the fossil fuel-fired power generation cost range, while the bands for each technology and year represent the 5th and 95th percentile bands for renewable projects.*

Between 2010 and 2020, 60 GW of new bioenergy for power capacity was added. The global weighted-average LCOE of bioenergy for power projects experienced a certain degree of volatility during this period, but ended the decade at around the same level it began, at USD 0.076/kWh – a figure at the lower end of the cost of electricity from new fossil fuel-fired projects. For the same period, hydropower added 715 GW, while the global weighted-average LCOE rose by 18%, from USD 0.038/kWh to USD 0.044/kWh. This was still lower than the cheapest new fossil fuel-fired electricity option, despite the fact that costs increased by 16% in 2020, year-on-year.

The global weighted-average LCOE of geothermal power has ranged between USD 0.071/kWh and USD 0.075/kWh since 2016. The global weighted-average LCOE of newly commissioned plants in 2020 was at the lower end of this range, at USD 0.071/kWh, having declined 4% year-on-year.

*The global weighted-average cost of electricity from onshore wind fell by 56% between 2010 and 2020, from USD 0.089/kWh to USD 0.039/kWh*

## RENEWABLE POWER GENERATION IS BECOMING THE DEFAULT ECONOMIC CHOICE FOR NEW CAPACITY

The decade 2010 to 2020 saw dramatic improvement in the competitiveness of solar and wind power technologies. In that period, CSP, offshore wind and utility-scale solar PV all joined onshore wind in the range of costs for new capacity fired by fossil fuels, when calculated without the benefit of financial support. Indeed, the trend is not only one of renewables competing with fossil fuels, but significantly undercutting them, when new electricity generation capacity is required.

In 2020, a total of 162 GW of the renewable power generation capacity added had electricity costs lower than the cheapest source of new fossil fuel-fired capacity. This was around 62% of total net capacity additions that year. In emerging economies, where electricity demand is growing and new capacity is needed, these renewable power generation projects will reduce costs in the electricity sector by at least USD 6 billion per year, relative to the cost of adding the same amount of fossil fuel-fired generation.

Since 2010, globally, a cumulative total of 644 GW of renewable power generation capacity has been added with estimated costs that have been lower than the cheapest fossil fuel-fired option in their respective year.[5] Prior to 2016, almost all of this was being contributed by hydropower, but since then it has increasingly included onshore wind and solar PV. Of the total, over the decade, 534 GW was added in emerging economies and could reduce electricity system costs in these by up to USD 32 billion in 2021 (USD 920 billion, undiscounted, over their economic lifetimes).

The results of competitive procurement of renewables through auctions or power purchase agreements (PPA) confirm the competitiveness of renewables. Data from the IRENA Renewable Auction and PPA Database indicate that utility-scale solar PV projects that have won recent competitive procurement processes – and that will be commissioned in 2022 – could have an average price of USD 0.04/kWh (Figure ES.3). This is a 30% reduction compared to the global weighted-average LCOE of solar PV in 2020 and is around 27% less (USD 0.015/kWh) than the cheapest fossil-fuel competitor, namely coal-fired plants.

The auction and PPA data suggest offshore wind costs will fall within the range of USD 0.05/kWh to USD 0.10/kWh in Europe in the period up to 2023, with new markets or delayed projects likely to have higher costs. The lower end of this range for offshore wind suggests projects will be competitive against wholesale electricity prices in a number of European markets. Meanwhile, the market for CSP is thin, but the data that is available suggests a continued decline in 2021, as this year sees the large Dubai Electricity and Water CSP project come online.

The data from the IRENA Renewable Cost Database and Auction and PPA Database therefore highlight the fact that utility-scale solar PV and onshore wind projects are, on average, able to produce power for less than the cheapest new fossil fuel-fired cost project. For offshore wind and CSP, costs will fall into the lower range for new fossil fuel-fired power plants.

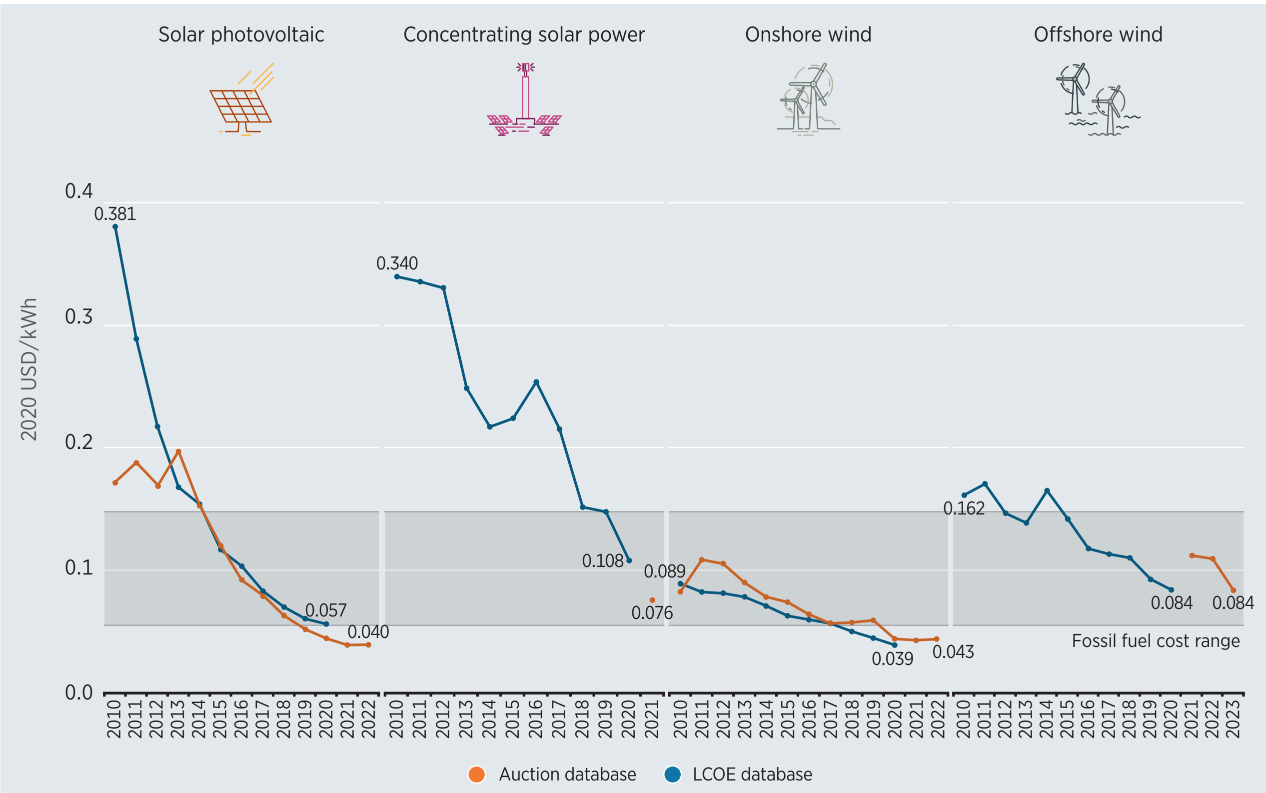
*5 Assumes the cheapest coal-fired power generation option increased from USD 0.05/kWh in 2010 to USD 0.055/kWh in 2020, due notably to average expected lifetime capacity factors falling over this period.*

The data also suggests that there is an increasing number of projects with very low electricity costs, at below USD 0.03/kWh. Indeed, the last 18 months has seen three record low bids for solar PV, starting with USD 0.0157/kWh in Qatar, USD 0.0135/kWh in the United Arab Emirates and USD 0.0104/kWh in Saudi Arabia. Surprisingly, values below USD 0.02/kWh are not impossible, even if they were unthinkable, even a few years ago. They do, however, require almost all factors affecting LCOE to be at their 'best' values.

These very low solar PV price levels imply that low-cost renewable hydrogen may already be in reach. The potential levelised cost of hydrogen, assuming the low solar PV and onshore wind prices from the recent auctions in Saudi Arabia, could be as little as USD 1.62/kilogramme of hydrogen (kg $H_2$). This compares favourably with the hypothetical cost of natural gas steam methane reforming, with today's carbon capture, utilisation and storage (CCUS) costs at between USD 1.45/kg $H_2$ and USD 2.4/kg $H_2$.

*Globally, since 2010, a cumulative total of 644 GW of renewable power generation capacity has been added with estimated costs that have been lower than the cheapest fossil fuel-fired option*

**Figure ES.3** The global weighted-average LCOE and PPA/auction prices for solar PV, onshore wind, offshore wind and CSP, 2010-2023




*Source: IRENA Renewable Cost Database*

*Note: The thick lines are the global weighted average LCOE, or auction values, by year. For the LCOE data, see Figure ES2 note. The band that crosses the entire chart represents the fossil fuel-fired power generation cost range.*

## LOW-COST RENEWABLE POWER IS STRANDING EXISTING COAL-FIRED POWER PLANTS

As costs for solar PV and onshore wind have fallen, new renewable capacity is not only increasingly cheaper than new fossil fuel-fired capacity, but increasingly undercuts the operating costs alone of existing coal-fired power plants.

Indeed, in Europe in 2021, coal-fired power plant operating costs are well above the costs of new solar PV and onshore wind (including the cost of $CO_2$ prices). Analysis for Germany and Bulgaria shows all the coal-fired plants studied have higher operating costs today than new solar PV and onshore wind. In the United States and India, operating costs for coal plants are lower, however, due largely – but not completely – to the absence of a meaningful price for $CO_2$. Nonetheless, the majority of existing Indian and U.S. coal plants have higher costs than solar PV and onshore wind, due to the very competitive costs for those two renewable technologies in those two countries.

In the United States, in 2021, between 77% and 91% of the existing coal-fired capacity has operating costs that are estimated to be higher than the cost of new solar or wind power capacity, while in India, the figure is between 87% and 91%. Adjusted to a levelised cost basis, the weighted average price from auction and power purchase agreements for solar PV in India for 2021 is USD 0.033/kWh, while for onshore wind it is USD 0.032/kWh. In the United States, the respective figures are USD 0.031/kWh and USD 0.037/kWh.

It's beyond the scope of this analysis, to determine if the value of coal-fired generation is higher than its costs. However, given that, between 2015 and 2018, the cost of utility-scale battery storage in the United States fell by 71% from USD 2 152/kWh to USD 635/kWh, even the value propositions of providing firm and flexible power generation are being eroded. The growing gap between new solar and wind power costs and the existing operating costs of an increasing number of coal-fired power plants provides an idea of the size of the economic opportunity early retirement of unabated coal presents.

**Table ES1** Capacity of uneconomic existing coal-fired power plants and annual savings in coal-fired generation, electricity costs and $CO_2$ emissions, 2021

| | Coal capacity with higher operating costs than new solar and wind | | Annual savings from replacing coal with new solar and wind | Annual $CO_2$ emissions reductions |
|---|---|---|---|---|
| | (GW) | +USD 5/MWh renewable integration costs (GW) | (USD billion/year) | (Mt $CO_2$/year) |
| Bulgaria | 3.7 | 3.7 | 0.7 | 18 |
| Germany | 28 | 28 | 3.3 | 99 |
| India | 193 | 141 | 6.4 | 643 |
| United States | 188 | 149 | 5.6 | 332 |
| Rest of the world | 724 | 488 | 16.3 | 1 881 |
| **World** | **1 137** | **810** | **32** | **2 973** |

*Source: IRENA analysis based on Carbon Tracker, 2018; Szabó, L., et al., 2020; IEA, 2021; Öko-Institut, 2017; Booz&Co, 2014; Energy-charts.de; DIW Berlin, Wuppertal Institut and EcoLogic, 2019; Gimon, et al., 2019; US EIA, 2021; and IRENA Renewable Cost Database*

## SOLAR AND WIND POWER TECHNOLOGIES HAVE REMARKABLE LEARNING RATES

The cost declines experienced from 2010 to 2020 represent a remarkable rate of descent. This not only has enormous implications for the competitiveness of renewable power generation technologies over the medium-term. It also has implications for other technologies that have similar characteristics and are needed in the energy transition.

Over the period 2010 to 2020 – which included 94% of cumulative installed renewable capacity additions – utility-scale solar PV had the highest estimated learning rate[6] for the global weighted-average total installed cost, at 34%. This technology also had the highest LCOE, at 39%. This is a value that exceeds virtually all previous learning rate analyses for solar PV based on data for the earlier period of deployment – when learning rates might have been expected to be higher than in later periods.

For onshore wind, the LCOE learning rate for the period 2010 to 2019 was 32% – slightly less than twice that for total installed costs. The importance of total installed cost reductions to the decline in electricity costs from utility-scale solar PV is clearly evident in Table ES2, given the closeness of the learning rates for total installed costs and LCOE. For the other technologies, performance improvements that have increased capacity factors have played a larger role in falling electricity costs. As a result, the LCOE learning rates for CSP, onshore and offshore wind are significantly higher than those for total installed costs.

**Table ES2** Learning rates for solar PV, CSP, onshore and offshore wind, 2010-2020 and 2010 to 2021/3

| | Learning rates | |
|---|---|---|
| | Total installed cost 2010-2020 | LCOE 2010-2021/23 |
| | (%) | (%) |
| Utility-scale solar PV | 34 | 39 |
| CSP | 22 | 36 |
| Onshore wind | 17 | 32 |
| Offshore | 9 | 15 |

*6 The learning rate is the percentage reduction in the price/cost for every doubling of cumulative installed capacity.*

01

# LATEST COST TRENDS

## INTRODUCTION

The year 2020 was marked by the global pandemic and the subsequent economic and human toll it took. One bright spot, however, was the resilience of global renewable energy technology supply chains, despite some initial disruption. Another was the renewable power sector's ability to adapt to the constraints created by the spread of the COVID-19 virus and continue to prosper.

Indeed, despite fears that the pandemic would hit project completion rates, 2020 turned out to be another record year for renewable power generation capacity deployment. As costs continued to fall, renewable power generation remained the mainstay of new power sector capacity additions, with renewables increasingly becoming the default source of least-cost new power generation.

Between 2000 and 2020, renewable power generation capacity worldwide increased 3.7-fold, from 754 gigawatts (GW) to 2 799 GW (IRENA, 2021a). With 261 GW of new renewable power generation capacity added in 2020, new renewable generation capacity additions were almost 50% higher than the 176 GW added in 2019 (IRENA, 2021a).

In 2020, solar photovoltaic (PV) was once again the largest contributor to the total, with new capacity additions growing by over one-fifth (22%), to 127 GW of new capacity commissioned.[1] Meanwhile, wind power capacity grew by 111 GW (with 105 GW of this growth in onshore wind power), which was almost twice as much as the 59 GW increase observed in 2019. Hydropower capacity increased by 20 GW, up from 12 GW added in 2019, while bioenergy power generation capacity increased by 2 GW, geothermal power by 164 MW and concentrating solar power (CSP) by 150 MW.

This growth in new capacity additions was not seen for fossil fuels or nuclear, resulting in the share of renewables in total power generation capacity growth reaching 82% in 2020 – up from 72% in 2019. Since 2015, renewables have accounted for more than half of all new, net capacity additions, while accounting for between 49% and 53% of the overall total during the period 2012 to 2014, inclusive.

1 *All data in this report, unless expressly indicated, refers to the year a project was commissioned. This is sometimes referred to as the 'COD' or commercial operation date. This is the date at which a project begins supplying electricity to the grid on a commercial basis. It therefore comes after any period of plant testing or injection of small quantities of electricity into the grid as part of the commissioning process.*

IRENA's cost analysis programme has been collecting and reporting the cost and performance data of renewable power generation technologies since 2012. This year, for the first time, the programme's report also includes a snapshot of IRENA's cost data for behind-the-meter battery storage and solar thermal technologies for industrial heat.

IRENA believes that having transparent, up-to-date cost and performance data from a reliable source is vital in ensuring that the potential of renewable energy is properly taken into account by policy makers, energy and climate modellers and other stakeholders. This is especially so given the high cost reduction rates and rapid growth in installed capacity of renewable energy technologies. The high learning rates[2] for renewable power technologies mean that data on the associated cost reductions from even one or two years ago can be significantly erroneous.

The two core sources of data for the cost and performance metrics contained in this report are the IRENA Renewable Cost Database and the IRENA Auctions and Power Purchase Agreement (PPA) databases.

The IRENA Renewable Cost Database has grown to include project-level cost and performance data for over 1900 GW of capacity from around 20 000 projects, either installed or in the pipeline for commissioning in the coming years.

The IRENA Auctions and PPA Database contains data on 13 000 projects, or programme results, where pricing data is not disclosed for individual winners, totalling around 582 GW of capacity.[3]

These databases contain significant overlap, which creates the possibility of directly comparing the projects in each. A later section of this chapter examines how these two databases can be used to reverse-engineer weighted average cost of capital (WACC) indicators and discusses the uncertainty in these.

In recent years, IRENA has expanded the range of cost and performance metrics it tracks. It now reports regularly on an increasing range of cost and performance metrics and has benefitted from the support of the European Commission in expanding this data collection process, using these metrics to help track innovation outputs.

Metrics such as the average size of onshore wind turbines, their hub heights and rotor diameters, for instance, can be used to explain the technology trends that have seen capacity factors for new projects increase through time.

This report benefits from this project with the European Commission, although the full results of this work will not be published until the second half of 2021.

This report presents a consistent set of core metrics with which to measure the cost and performance of renewable power generation technologies, and allows for a meaningful understanding in variations between countries and technologies. These variations are reported across each technology, with differences arising due to the nature of the technologies (*e.g.,* solar PV modules and wind turbines) or due to data availability. Annex I discusses in detail the metrics used, the boundary conditions for cost calculations and the key assumptions taken.

*2 Learning rates represent the average percentage cost reduction experienced for every doubling of cumulative installed capacity.*

*3 These numbers increase to 587 GW and 26 600 projects, if projects smaller than 1 MW are included.*

The overall goal is to assess the levelised cost of electricity (LCOE)[4] and its underlying drivers. The LCOE of a given technology is the ratio of lifetime costs to lifetime electricity generation, both of which are discounted back to a common year using a discount rate that reflects the average cost of capital. The cost and performance metrics common to all chapters therefore include total installed costs (including cost breakdowns, when available), capacity factors, operations and maintenance costs (O&M) and LCOE.

These varied metrics allow IRENA to not only follow the evolution of the costs of renewable power generation technologies, but also to analyse what the underlying drivers are, at a global level and in individual countries. These layers of data and the granularity available provide deeper insights for policy makers and other stakeholders.

Yet, although LCOE is a useful metric for a first-order comparison of the competitiveness of projects, it is a static indicator that does not take into account interactions between generators in the market. The LCOE does not take into account either that the profile of generation of a technology may mean that its value is higher or lower than the average market price it might receive. As an example, CSP with thermal energy storage has the flexibility to target output in high cost periods of the electricity market, irrespective of whether the sun is shining. The LCOE also fails to take into account other potential sources of revenue or costs. For example, hydropower can earn significant revenue in some markets from providing ancillary grid services.

This is not typically the case for stand-alone variable renewable technologies, but improved technology for solar and wind technologies is making these more grid friendly. Hybrid power plants, with storage, or other renewable power generation technologies, plus the creation of, virtual, power plants that mix generating technologies, can all transform the nature of variable renewable technologies.

Thus, although LCOE is a useful metric as a starting point for deeper comparison, it is not a substitute for electricity system simulations that can determine the long-run mix of new capacity to minimise overall system costs, while meeting overall demand minute-by-minute over the year. This should be taken into account when interpretating the data presented in this report.

There are a few additional important points to remember when evaluating the results presented here:

- All monetary values are in real, 2020 USD, that is to say, taking into account inflation.
- Results for LCOEs are calculated using the assumption of a real cost of capital of 7.5% in 2010, declining linearly to 5% in 2020 in Organisation of Economic Co-operation and Development (OECD) countries and China. In the rest of the world, the assumption is a real cost of capital of 10% in 2010, declining linearly to 7.5% by 2020, unless explicitly mentioned.
- All total installed cost data and LCOE calculations *exclude* the impact of any financial support available to them.

*4 Note that "LCOE" and "cost of electricity" are used interchangeably in this report, as well as the terms "weighted-average LCOE" and "weighted-average cost of electricity", where the weighting is by installed MWs.*

- All data presented here is for the year of commissioning and is for new capacity added.[5] Lead times are important, with planning, development and construction sometimes taking two to three years for solar PV and onshore wind, while it can take five years or more for CSP, fossil fuels, hydropower and offshore wind.
- The data, with the exception of residential and commercial solar PV, is for utility-scale projects of at least 1 MW. In recent years, only solar PV and hydropower projects in the IRENA Renewable Cost Database include any sizeable deployment of projects in the 1 to 10 MW range.
- Data for costs and performance for 2020 is preliminary and subject to change.

An important change from last years report is the reduction in the WACC assumptions through time to reflect recent changes in the financing conditions facing renewable power generation projects. IRENA's cost analysis work has focused on project-specific cost and performance data, in order to account for the very project-specific variation in these parameters. It has, however, been almost impossible to get project-specific cost data for the WACC.

IRENA has been aware of this gap in its knowledge. In recent years, IRENA's analysis has highlighted that these WACC assumptions were likely to have become too high and were likely to be increasingly overstating the cost of electricity from solar PV and onshore wind, in particular (IRENA, 2018; 2020). An increasing body of research has also been able to provide evidence that today's WACC for solar and wind power technologies – at least in a number of countries – is often lower than the assumed values of 7.5% and 10% (Egli, F. *et al.*, 2018).

For this edition of Renewable Power Generation Costs, the WACC assumptions have been lowered, but this is an interim solution, that still lacks the desired granularity. The 2021 edition of this report will include country and technology specific WACC assumptions from a cost of capital benchmarking exercise, as well as a global survey of renewable power generation financing costs that is currently being rolled out as a joint effort between IRENA, IEA Wind and ETH Zurich (see Box 1.1 and Annex I for more information).

## SOLAR AND WIND POWER COST TRENDS IN 2020

For renewable power generation – and solar and wind power technologies in particular – the data from the IRENA Renewable Cost Database and capacity statistics bear witness to a remarkable decade of change.

New capacity additions have exceeded almost all expectations, driven by growth in both the more established renewable power generation technologies (bioenergy for power, geothermal and hydropower) and solar and wind power technologies. The decade 2010 to 2020 saw solar and wind power technologies add 1 225 GW of new capacity, with wind power capacity growing fourfold, to 773 GW, and solar power 17-fold, to 714 GW.

The continued competitiveness of the most established renewable power generation technologies (hydropower, bioenergy and geothermal) has ensured growth where unexploited economic resources of what are typically dispatchable, low-cost power sources exist. It is the continued improvement in the competitiveness of solar and wind power technologies, however, that has really marked the last decade.

*5 No data is presented, for instance, on average fleet capacity factors.*

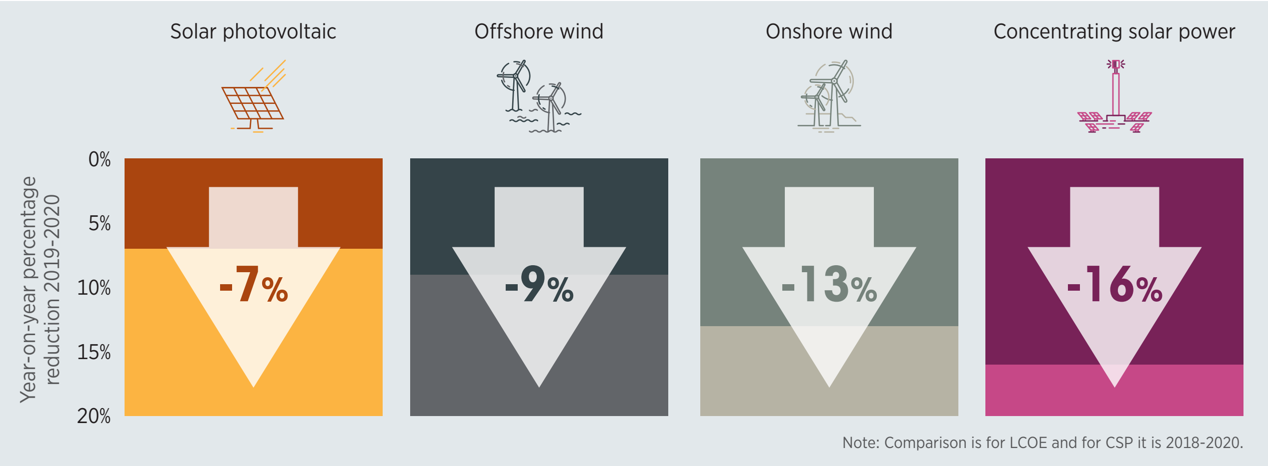
In 2020, the global weighted-average LCOE of onshore wind fell by 13%, year-on-year, (Figure 1.1), from USD 0.045/kilowatt hour (kWh) to USD 0.039/kWh. This was slightly higher than the rate of decline in 2019 and was driven by a 9% decline in the global weighted-average total installed cost. China connected an estimated 69 GW to the grid in 2020, two-thirds of the new capacity deployed in 2020.

In 2020, the global weighted-average LCOE of utility-scale solar PV fell by 7%, year-on-year, from USD 0.061/kWh to USD 0.057/kWh. The global weighted-average total installed cost of utility-scale solar PV fell by 12% in 2020 to just USD 883/kW. The percentage reduction in LCOE was lower than the 13% reduction experienced in 2019, as the decline in total installed costs experienced in 2020 was partially offset by a reduction in the global weighted-average capacity factor of new projects that year.[6] This was driven by the fact that deployment in 2020 was, on balance, weighted to areas with poorer solar resources than in 2019.[7] Similar to the situation for onshore wind, China was the largest market for new capacity, accounting for an estimated 45% of the new utility-scale solar PV capacity added in 2020.

The offshore wind market, which added 6 GW in 2020, saw the global weighted-average cost of electricity of new projects fall by 9%, year-on-year, from USD 0.093/kWh to USD 0.084/kWh. This was a sharper decline than experienced in 2019, when China accounted for around a third of new capacity additions, with this rising to around half in 2020. That year saw a decline in the global weighted-average capacity factor of new projects added.

The global weighted-average LCOE of new CSP projects commissioned in 2020 fell by 49%, year-on-year. This result is somewhat atypical, however, as the global weighted-average LCOE in 2019 was pushed up by two much delayed Israeli projects, while 2020 was characterised by the commissioning of just two plants, both in China. Looking at the figures between 2018 and 2020 reveals a compound annual rate of decline of 16% per year, which is more presentative of recent rates of cost reduction.

**Figure 1.1** Global LCOE from newly commissioned utility-scale solar and wind power technologies, 2019-2020




*Source: IRENA Renewable Cost Database*

*Note: The comparison for CSP is the annual compound percentage reduction for 2018-2020, given that the 2019 value was something of an anomaly. Comparing against 2019 would see the year-on-year reduction rise to 49%.*

6 *All solar PV capacity factors quoted in this report are the so-called AC/DC capacity factors, given all installed cost data for solar PV is quoted "per-watt direct current".*

7 *This result should be treated with caution, given the increasing importance of bifacial modules and single-axis trackers, where data availability lags total installed cost and has a material impact on capacity factors.*

## COST TRENDS 2010-2020: A DECADE OF DECLINE

For newly commissioned projects, the global weighted-average LCOE of utility-scale solar PV fell by 85% between 2010 and 2020, from USD 0.381/kWh to USD 0.057/kWh (Figure 1.2), as global cumulative installed capacity of all solar PV (utility scale and rooftop) increased from 40 GW to 707 GW. This represented a precipitous decline, from being more than twice as costly as the most expensive fossil fuel-fired power generation option to being at the bottom of the range for new fossil fuel-fired capacity.[8]

This reduction has been primarily driven by declines in module prices – which have fallen by 93% since 2010, as module efficiency has improved and manufacturing has increasingly scaled-up and been optimised – and reductions in balance of system costs. As a result, the global weighted-average total installed cost of utility-scale solar PV fell by 85% between 2010 and 2020. Capacity factors have also risen, but predominantly due to the growth in new markets that saw a shift in the share of deployment to regions with better solar resources. Technology improvements that have reduced system losses have played a small but important role. The recent trend towards an increased use of trackers and bifacial modules – which increase yields for a given resource – is also having an impact. Unfortunately, the data is less clear on exactly what impact this is having on the global weighted-average capacity factor in 2020.[9]

The global weighted-average LCOE in 2020 of USD 0.057/kWh is at the lower end of the range for new fossil fuel-fired electricity projects, while utility-scale solar PV projects are increasingly undercutting even the cheapest options from new fossil fuel-fired power plants.

For onshore wind projects, the global weighted-average cost of electricity fell by 56%, from USD 0.089/kWh to USD 0.039/kWh, between 2010 and 2020. This decline occurred as cumulative installed capacity grew from 178 GW to 699 GW. Cost reductions for onshore wind were driven by falls in turbine prices and balance of plant costs, as well as higher capacity factors from today's state-of-the-art turbines. Reductions in O&M costs have also occurred as a result of increased competition among O&M service providers, greater wind farm operational experience, improved preventative maintenance programmes. Improvements in technology have also resulted in more reliable turbines, with increased availability.

The global weighted-average total installed cost of newly commissioned onshore wind projects fell from USD 1 971/kW in 2010 to USD 1 355/kW in 2020. At the same time, continued improvements in wind turbine technology, wind farm siting and reliability have led to an increase in average capacity factors, with the global weighted average increasing from 27% in 2010 to 36% in 2020.[10] Technology improvements, such as higher hub heights, larger turbines and swept blade areas mean today's wind turbines can achieve higher capacity factors from the same wind site than their smaller predecessors.

*8 The fossil fuel-fired power generation cost range by country for the G20 group, and fuel, is estimated to be between USD 0.055/kWh and USD 0.148/kWh. The lower bound represents new, coal-fired plants in China and is based on IEA, 2020.*

*9 Project-level data on the use of trackers and module types is less comprehensive and available with a greater lag than for project costs.*

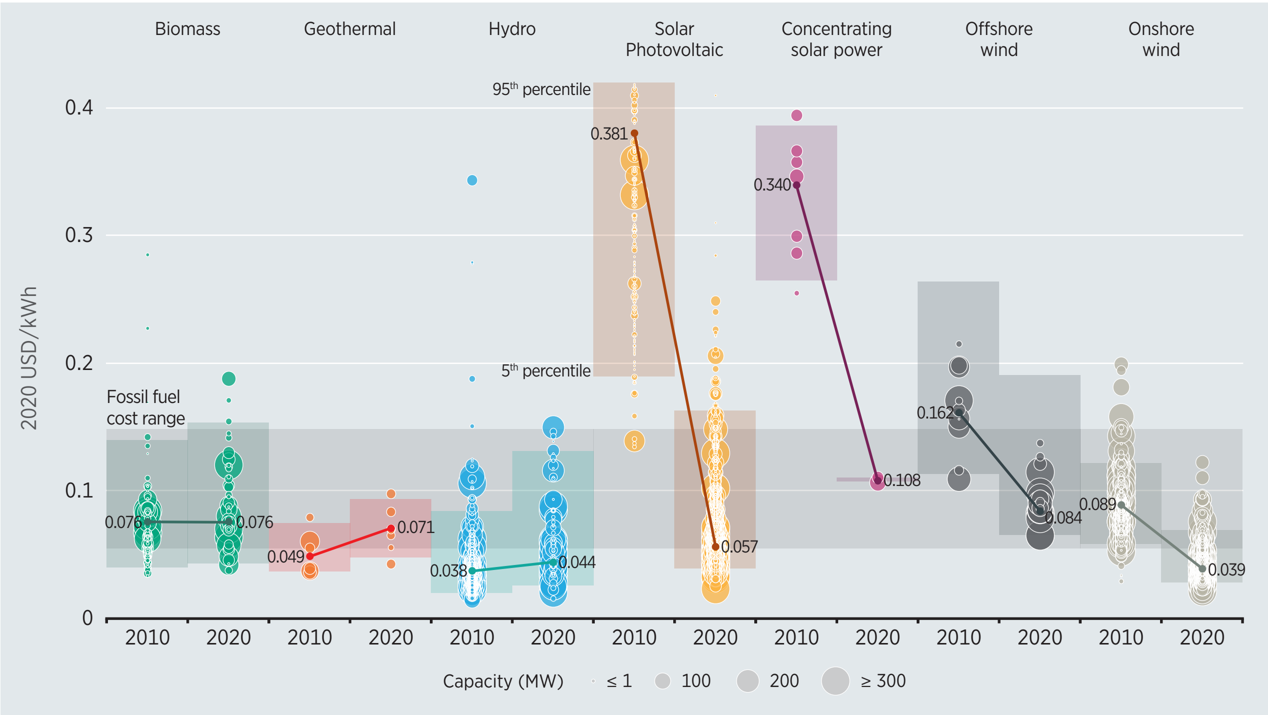
*10 As already noted, the global weighted-average capacity factor for newly commissioned onshore wind projects in 2020 is potentially open to revision, given the uncertainty around the geographical distribution of new capacity connected to the grid in China in 2020.*

Over the period 2010 to 2020, the global weighted-average cost of electricity from CSP fell from USD 0.340/kWh to USD 0.108/kWh. With just two projects commissioned in 2020 – both in China – these results, however, reflect only the national circumstances of that country. Having said that, the 68% decline in the cost of electricity from CSP – into the middle of the range of the cost of new capacity from fossil fuels – remains a remarkable achievement. For comparison, the global cumulative installed capacity for CSP of 6.5 GW at the end of 2020 was slightly less than a hundredth of the capacity of solar PV installed.

Similarly to solar PV, the decline in cost of electricity from CSP has been driven by reductions in total installed costs. Yet, improvements in technology that have seen the economic level of storage increase significantly have also played a role in increasing capacity factors. The global weighted-average capacity factor of newly added capacity in 2010 was 30%, while for plants added in 2020, it was 42%.

For offshore wind, the global weighted-average LCOE of newly commissioned projects declined from USD 0.162/kWh in 2010 to USD 0.084/kWh in 2020, a reduction of 48% in ten years. The cumulative installed capacity of offshore wind at the end of 2020 reached 34 GW, which is around 5% of that of onshore wind.

**Figure 1.2** Global LCOEs from newly commissioned, utility-scale renewable power generation technologies, 2010-2020




*Source: IRENA Renewable Cost Database*

*Note: This data is for the year of commissioning. The diameter of the circle represents the size of the project, with its centre the value for the cost of each project on the Y-axis. The thick lines are the global weighted-average LCOE values for plants commissioned in each year. Real WACC was 7.5% in 2010 and 5% in 2020 for OECD countries and China, and 10% in 2010 and 7.5% in 2020 for the rest of the world. The single band represents the fossil-fuel fired power generation cost range, while the bands for each technology and year represent the 5th and 95th percentile bands for renewable projects.*

Annual values for the global weighted-average total installed costs, capacity factors and LCOEs are relatively volatile, given the relatively small number of projects added in some years. In recent times, the growth in new markets – both within Europe, where the first offshore wind markets developed, and globally have also added – more 'noise' to the data for any single year-on-year comparison.

From 2010 to 2020, total installed costs fell by around 32%, while capacity factors increased by around one-fifth, from 38% in 2010 to 42% in 2019, before dropping back to 40% in 2020. The drop in the global weighted-average capacity factor for plant commissioned in 2020 was driven by China dominating new capacity additions. China's offshore wind farms are still predominantly inter-tidal, or near shore, and in addition to not using the latest offshore wind turbine designs, these also have to contend with poorer-quality wind resources.

The installed costs and capacity factors of bioenergy for power, geothermal and hydropower are highly project specific. As a result, and due to different cost structures in different markets, there can be significant year-to-year variability in global weighted-average values when deployment is relatively thin and the share of different countries/regions in new deployment varies significantly, year-to-year.

Between 2010 and 2020, 60 GW of new bioenergy for power capacity was added. The global weighted-average LCOE of bioenergy for power projects experienced a certain degree of volatility during this period, but ended the decade at around the same level it began, at USD 0.076/kWh – a figure at the lower end of the cost of electricity from new fossil fuel-fired projects. For the same period, hydropower added 715 GW, while the global weighted-average LCOE rose by 16%, from USD 0.038/kWh to USD 0.044/kWh. This was still lower than the cheapest new fossil fuel-fired electricity option, despite the fact that costs increased by 10% in 2020, year-on-year.

The global weighted-average LCOE of geothermal has ranged between USD 0.071/kWh and USD 0.075/kWh since 2016. The global weighted-average LCOE of newly commissioned plants in 2020 was at the lower end of this range, at USD 0.071/kWh, having declined 4% year-on-year.

The decade 2010 to 2020 saw dramatic improvement in the competitiveness of solar and wind power technologies. In that period, CSP, offshore wind and utility-scale solar PV all joined onshore wind in the range of costs for new capacity fired by fossil fuels, when calculated without the benefit of financial support. Indeed, the trend is not only one of renewables competing with fossil fuels, but significantly undercutting them, when new electricity generation capacity is required.

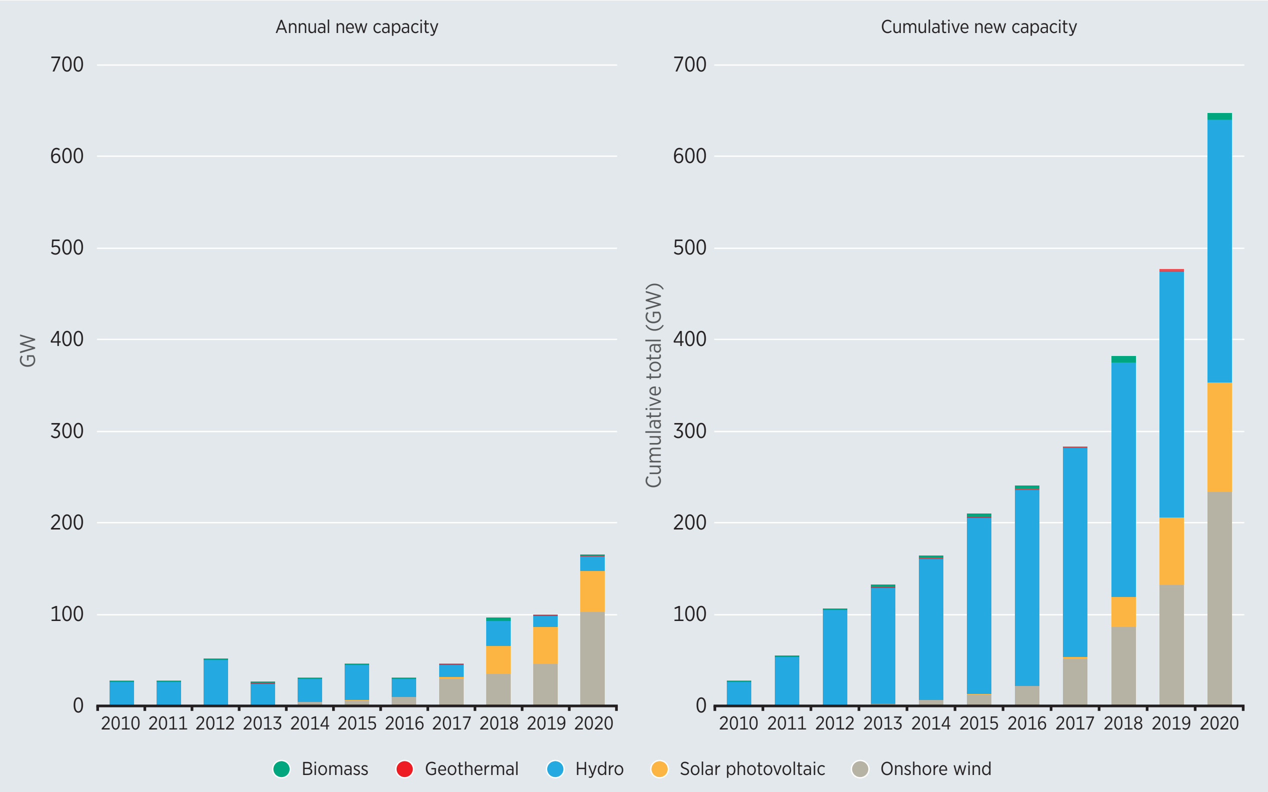
The data shows that without financial support, renewables are undercutting fossil fuels by a substantial margin in an increasing number of cases. In 2020, around 100 GW of the onshore wind projects commissioned that year had electricity costs that were lower than the cheapest fossil fuel-fired option, a figure around 58 GW more than in 2019. The continued decline in the costs of solar PV also meant that in 2020, 45.5 GW of utility-scale solar PV projects commissioned had lower costs than the cheapest fossil fuel-fired option, up from 28 GW in 2019. For hydropower, 16.8 GW of the projects commissioned had costs that were less than the lowest cost fossil fuel-fired power generation option. With around 440 MW of geothermal and bioenergy for power plants also having an LCOE lower than the cheapest new fossil fuel-fired capacity option, a total of 162 GW of the renewable power generation capacity added in 2020 had costs lower than the lowest cost source of new fossil fuel-fired capacity.

This was around 62% of the total net increase in global renewable power generation capacity in 2020. In 2019, 56% of all new capacity added had lower costs than the cheapest new fossil fuel-fired option, but with lower deployment in 2019, this means that the capacity added in 2020 that was cheaper than fossil fuels doubled, in absolute terms.

In emerging economies, where electricity demand is growing and new capacity is needed, these renewable power generation projects will significantly reduce electricity system costs over the life of their operation. In 2021, in non-OECD countries, these projects will reduce costs in the electricity sector by at least USD 6 billion, relative to the cost of adding the same amount of fossil fuel-fired generation. Two-thirds of these savings (a total of USD 3.9 billion in 2021) will come from onshore wind. Hydropower, with its higher capacity factors, contributes USD 1.3 billion to these savings, with utility-scale solar PV accounting for most of the remaining USD 0.7 billion. The cumulative undiscounted savings of the above projects, over their economic lives, will reach around USD 156 billion. In addition to these direct cost savings, too, the substantial economic benefits of reduced carbon dioxide emissions and local air pollutants also need to be factored in when considering the total benefits.

Since 2010, globally, around 644 GW of renewable power generation capacity has been added that had costs lower than the cheapest fossil fuel-fired option in that year.[11] Prior to 2016, almost all of this was being contributed by hydropower, but the situation has rapidly changed as the costs of onshore wind and solar PV in particular have fallen.

**Figure 1.3** Annual and cumulative total new renewable power generation capacity added at a lower cost than the cheapest fossil fuel-fired option, 2010-2020




*Source: IRENA Renewable Cost Database*

*11 Assumes the cheapest coal-fired power generation option increased from USD 0.05/kWh in 2010 to USD 0.055/kWh in 2020, due notably to average expected lifetime capacity factors falling over this period.*

In 2017, 29 GW of new onshore wind capacity was added that had lower costs than fossil fuels, exceeding for the first time that added by hydropower (14 GW). The year 2017 was also the first time that utility-scale solar PV added significant capacity that was cheaper than the fossil fuel-fired option. Looking just at non-OECD countries again, the annual savings in 2021 of the 534 GW of capacity added between 2010 and 2020 at a cost lower than the cheapest fossil fuel option are estimated to be in the order of USD 32 billion for the year 2021, with hydropower accounting for USD 24 billion of this total. Over their economic lifetime, this 534 GW in emerging economies represents a reduction in electricity generation costs of more than USD 920 billion.

### Total installed costs by technology: 2010-2020

Figure 1.4 presents the trend in the global weighted-average total installed costs of renewable power generation technologies between 2010 and 2020. Two major trends stand out in the data. The first, is that the more established renewable technologies bioenergy – for power, geothermal and hydropower – have not seen significant cost reductions. While the second is the strong reductions in total installed costs for solar and wind technologies.

Between 2010 and 2020, the global weighted-average total installed costs of newly commissioned hydropower plants by year increased by around half, from USD 1 269/kW in 2010 to USD 1 870/kW for plants commissioned in 2020. Indeed, with the exception of declines in 2015 and 2018, the global weighted-average total installed cost of hydropower has followed an increasing trend over the past ten years. Most of this increase happened in the period 2010 to 2017, however, when the global weighted-average total installed cost increased from USD 1 269/kW to USD 1 806/kW – albeit not linearly. The figure has been in the approximate range of USD 1 700/kW to USD 1 870/kW ever since. Despite this volatility, the new higher average cost level seems to be driven by a shift towards the exploitation of sites with more challenging civil engineering conditions, resulting in higher costs. For example, the weighted-average total installed cost of hydropower in China in the period 2010 to 2015 was USD 1 173/kW, while for the period 2016 to 2020 (inclusive) it increased by 12% to the still low level of USD 1 314/kW. In the rest of Asia, this cost figure rose 15%, from USD 1 507/kW to USD 1 730/kW, over the same two periods.

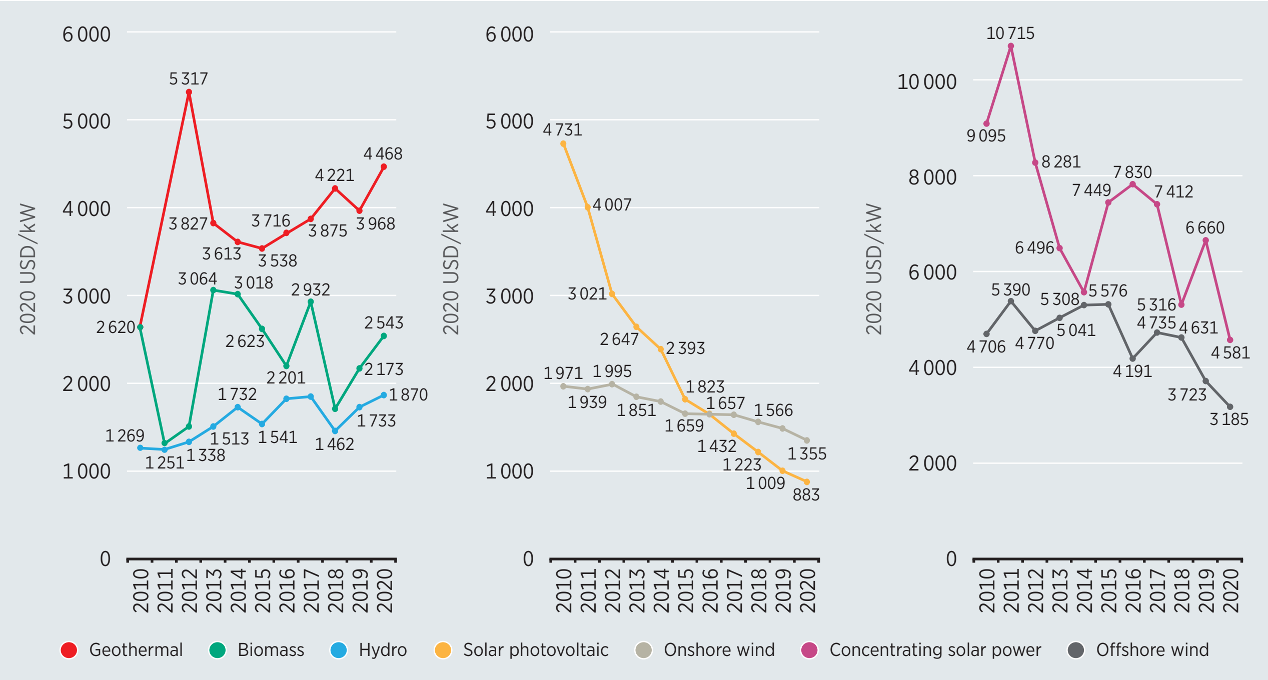
For geothermal power plants, the data for recent projects shows that total installed costs for most projects have largely fallen within the range USD 2 000/kW to USD 6 000/kW, although smaller projects in new markets have experienced higher costs. During the period 2014-2019, global weighted-average total installed costs were between USD 3 613/kW and USD 3 968/kW, before rising to USD 4 468/kW in 2020.

For bioenergy projects newly commissioned in 2020, the global weighted average total installed cost was USD 2 543/kW. This represented an increase on the 2019 weighted average of USD 2 173/kW. Annual global weighted averages for bioenergy are strongly influenced by both the technology mix and the geographical location of the plants commissioned. For example, technology costs are typically higher in countries that are members of the OECD, where emissions regulations are often stricter, but can also vary widely given the heterogeneity of bioenergy feedstocks.

The global weighted-average total installed cost of onshore wind farms declined from USD 1 971/kW in 2010 to USD 1 355/kW in 2020. The country/region weighted-average total installed cost for onshore wind in 2020 ranged from a low of USD 1 038/kW in India, to a high of USD 3 189/kW in 'Other Asia' (Asia excluding China and India).

When looking at utility-scale solar PV and onshore wind power total installed costs, what is noticeable is the more rapid decline in solar PV costs. The global weighted-average total installed costs of utility-scale solar PV declined by 81% between 2010 and 2020, from USD 4 731/kW in 2010, to just USD 883/kW in 2020. In 2010, utility-scale solar PV total installed costs were 2.4 times larger than onshore wind in 2010. By 2017, they had fallen below the global weighted-average total installed cost of onshore wind and in 2020 the global weighted-average total installed cost of onshore wind was 1.5 times higher than that of utility-scale solar PV.

**Figure 1.4** Global weighted-average total installed costs by technology, 2010-2020



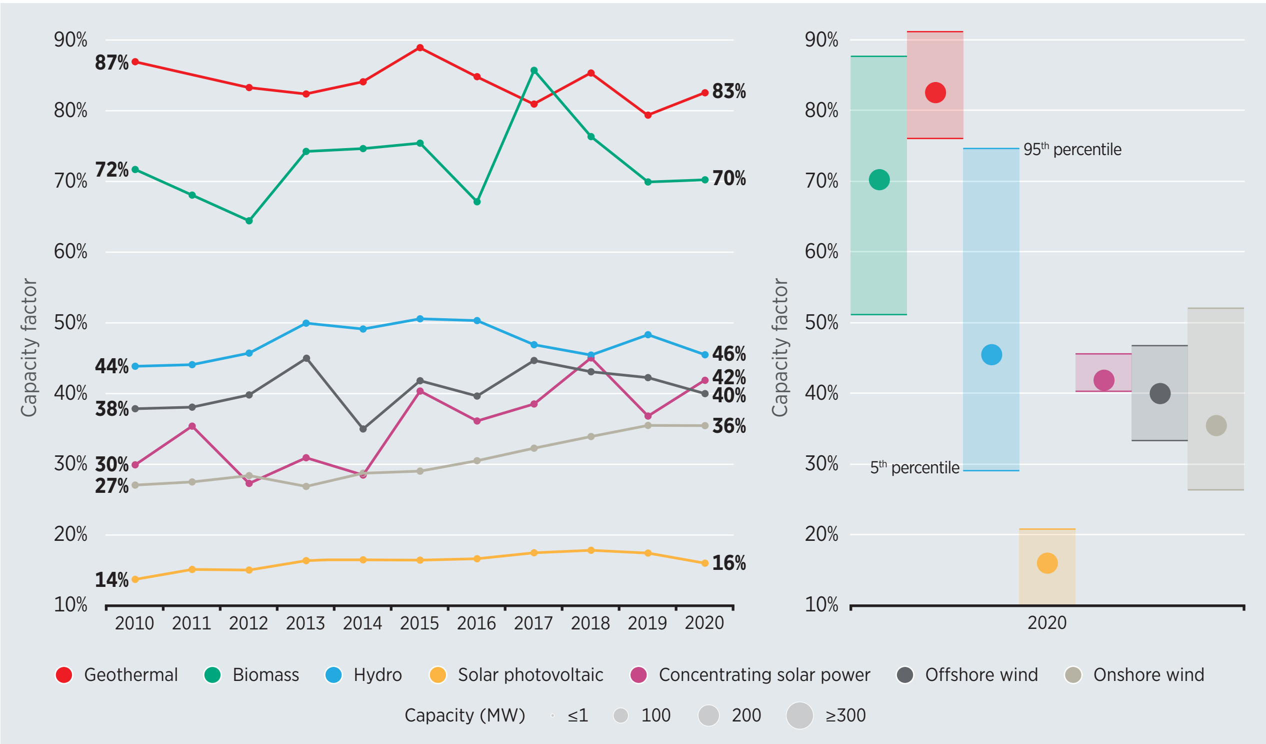

*Source: IRENA Renewable Cost Database*

The global weighted-average total installed costs of CSP and offshore wind remain higher than all their renewable counterparts, with the exception that since 2019, offshore wind has fallen below the global weighted-average total installed cost of geothermal power plants. With a fall of 50% between 2010 and 2020, the global weighted-average total installed cost of CSP plants have fallen faster than those of onshore wind. Given the global weighted-average total installed cost of CSP in 2010 was USD 9 095/kW, however, this reduction was not enough to see their costs drop below those of offshore wind, by 2020.For offshore wind, between 2010 and 2020, global weighted-average total installed costs fell 32%, from USD 4 706/kW to USD 3 185/kW. The global weighted-average total installed cost peaked at USD 5 308/kW in 2013, representing a figure 41% higher than its 2020 value. This cost reduction was sufficient to ensure that the global weighted-average total installed cost of offshore wind in 2020 was still around 30% lower than that of CSP.

### Capacity factors by technology: 2010 to 2020

Figure 1.5 presents the trends in global weighted-average capacity factors between 2010 and 2020. Bioenergy for power and geothermal power plants have the highest capacity factors. Geothermal projects are typically designed to achieve high lifetime load factors, although this necessitates significant investment over their lifetime to re-work production wells or drill new ones as the reservoir responds to the extraction and reinjection of fluids. The capacity factors of bioenergy plants depend heavily on the availability of feedstocks. Plants with steady year-round supplies (*e.g.,* municipal solid waste plants and those utilising forestry product residues) can achieve capacity factors to rival those of geothermal plants. Those reliant on seasonal supplies of agricultural residues tend to have lower capacity factors.

**Figure 1.5** Global weighted-average utility-scale capacity factor by technology, 2010-2020



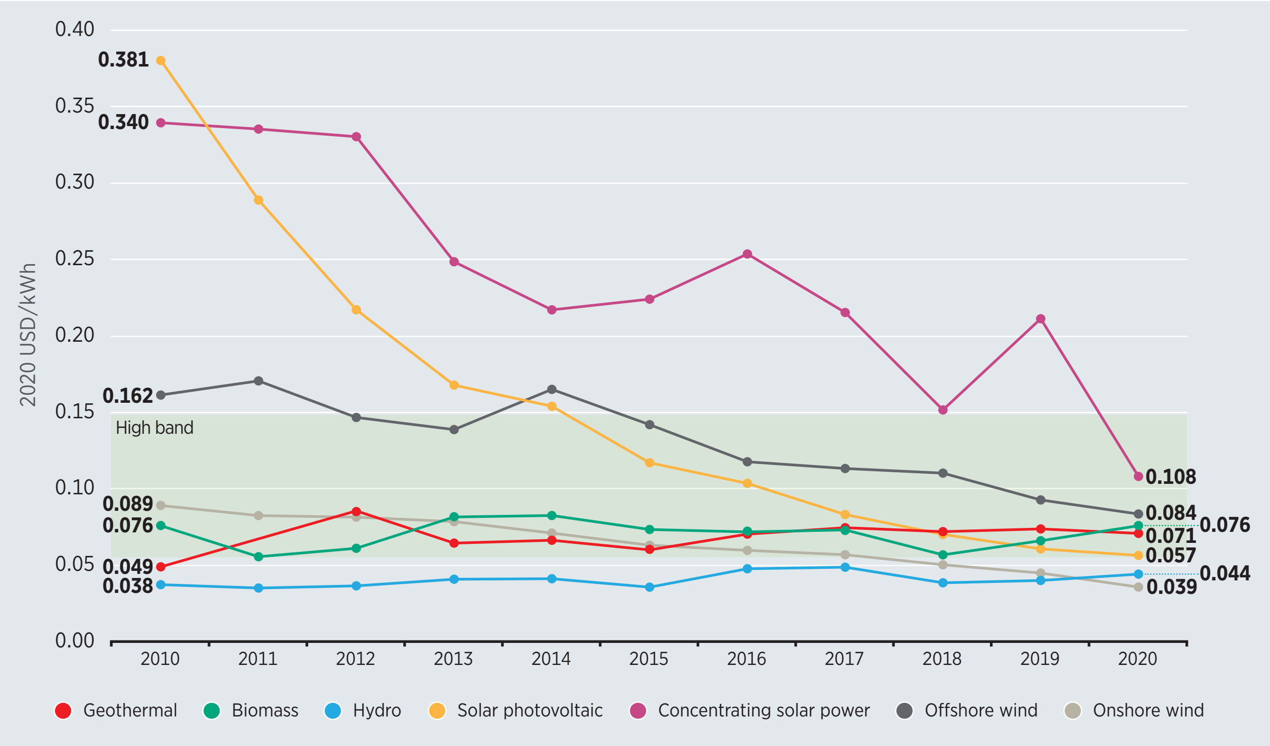

*Source: IRENA Renewable Cost Database*

The global weighted-average capacity factors of hydropower and offshore wind were materially higher than those for CSP, onshore wind and utility-scale solar PV in 2010. With technology improvements, however, there is now little to sperate CSP, offshore wind and hydropower. Onshore wind remains somewhat below these three and solar PV remains the renewable power generation technology with the lowest capacity factor.

The situation is more nuanced when we look at the 5th and 95th percentiles of projects in the IRENA Renewable Cost Database, however. The 5th and 95th percentiles of onshore wind extend much further than for offshore wind and CSP. For onshore wind, the wide range of project-level capacity factors highlights that this technology's deployment is larger and more geographically diverse than that of CSP and offshore wind. This means that deployment occurs in a very heterogenous set of sites, with widely varying wind resource levels that are seeing different turbine technologies being deployed. It also serves to highlight again, the very low rates of deployment in CSP in 2020, with a very narrow range based on just two projects.

Figure 1.6 presents the LCOE trends for renewable power generation technologies between 2010 and 2020. In addition to the dramatic fall in LCOE, the utility-scale solar PV LCOE curve declines remarkably smoothly; a function of the steady decline in global weighted-average total installed costs and capacity factors for this technology. The global weighted-average LCOE of utility-scale solar PV fell below that of CSP in 2011, that of offshore wind in 2014 and that of geothermal and bioenergy in 2019. The global weighted-average LCOE of utility-scale solar PV fell into the fossil fuel-fired cost range in 2015 and reached the lower end in 2020. The global weighted-average LCOE of onshore wind fell below that of geothermal in 2012, that of bioenergy in 2013 and that of hydropower, previously the cheapest source of new renewable power generation capacity in 2020. It fell below the cheapest new source of fossil fuel-fired electricity in 2018.

**Figure 1.6** Global weighted-average utility-scale LCOE by technology, 2010-2020




*Source: IRENA Renewable Cost Database*

The global weighted-average LCOE of offshore wind fell into the cost range of new fossil fuel-fired capacity briefly in 2012 and then, permanently from 2015. CSP has flirted with the upper range of the fossil fuel-fired cost range in 2018, before falling solidly within in 2020. The global weighted-average LCOE for bioenergy, geothermal and hydropower has seen more variation year-to-year, with the exception being CSP. The main trends of note have been the rise in hydropower costs and, to a lesser extent, those of geothermal.

## AUCTION AND POWER PURCHASE AGREEMENT PRICE TRENDS

Figure 1.7 present the results of comparing the LCOE data in the IRENA Renewable Cost Database with the prices in the IRENA Auction and PPA Database. The auction and PPA prices in this figure have been deflated to real values where the contract terms specified there was no indexation of award prices. The impact of the Investment Tax Credit (ITC) on solar PV and Production Tax Credit (PTC) on onshore wind auction and PPA prices in the United States has also been corrected for. In addition, any projects where the auction or PPA prices are clearly not comparable to an 'all-in' LCOE value have been removed from the chart (see Annex I for more details). For both databases, Figure 1.4 shows the results for the year of commissioning, not the award year, in the case of the Auction and PPA Database.

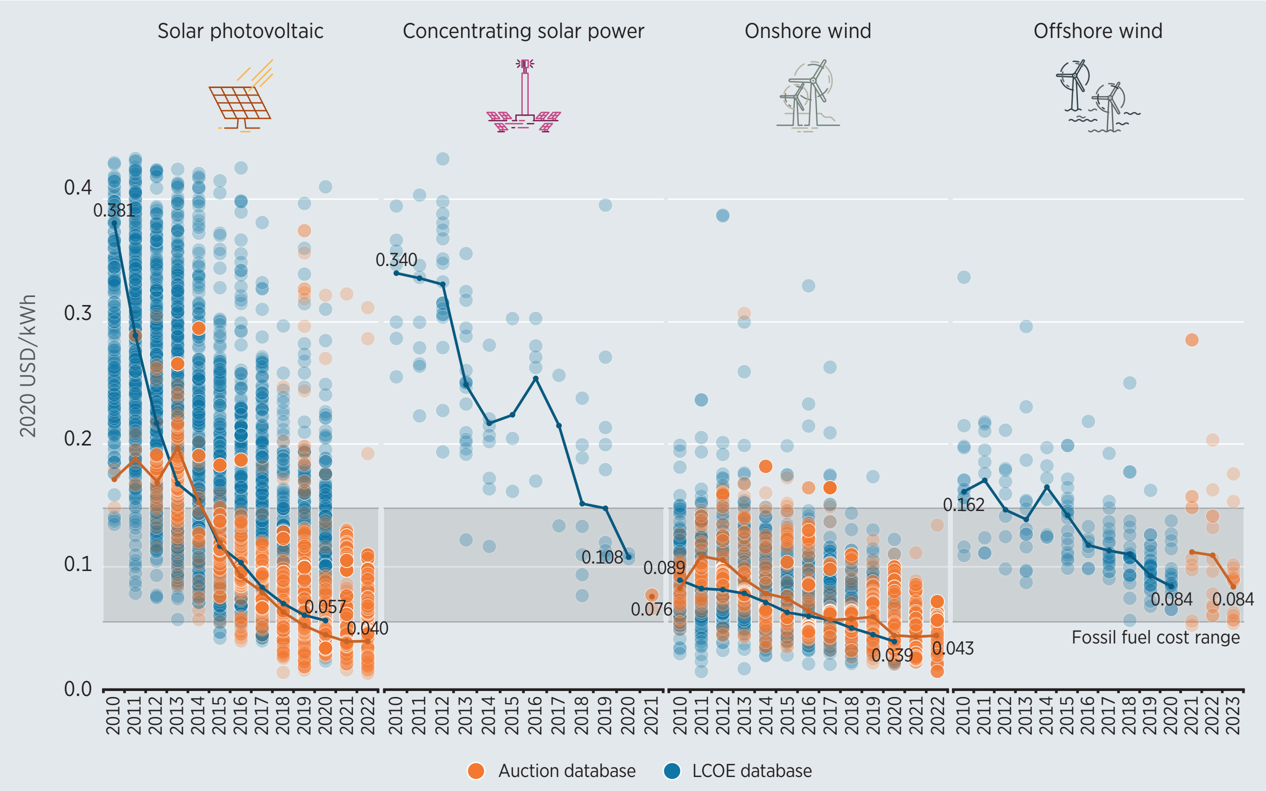
The data in Figure 1.7 shows that for onshore wind, the global weighted-average LCOE in 2020 was around USD 0.04/KWh. The global weighted-average price for electricity from the 25.6 GW of utility-scale onshore wind projects in the IRENA Auction and PPA Database expected to be commissioned in 2021, is USD 0.043/kWh. It is also around the same level in 2022 for the 33.8 GW of capacity in the database expected to be commissioned that year.

The slightly higher values in the IRENA Auction and PPA database compared to the LCOE value for 2020, is largely due to the fact that China dominated deployment in 2020, with around two-thirds of capacity, while the share of capacity in the IRENA Auction and PPA database is lower for China and higher for the European markets, which are, on average, more expensive. A similar dynamic is at play in projects anticipated to be online in 2022. In addition, at this time, some important low-cost onshore wind markets are under represented in the IRENA Auction and PPA Database. Additional data for PPA results in the United States, in particular, will alter this outlook when they become available in the coming months.

The outlook for 2021 and 2022, therefore, is that the global weighted-average cost of electricity from onshore wind is likely to be at least USD 0.012/kWh (22%) lower than the cheapest source of new fossil-fuel fired capacity. Overall, 44.4 GW of the capacity in the IRENA Auction and PPA database for onshore wind that is expected to be commissioned in 2021 and 2022 costs less than the cheapest fossil fuel-fired option, or 75% of the total projects in the database for those years.

For utility-scale solar PV, the data in the IRENA Auction and PPA Database has a weighted-average price for solar PV of USD 0.039/kWh in 2021 and USD 0.04/kWh in 2022. This is for a total of 18.8 GW of capacity in the database that is expected to be commissioned in 2021 and 26.7 GW that is expected to be commissioned in 2022. Of the projects in the Auction and PPA database that are expected to be commissioned in 2021 and 2022, 74% (33.8 GW) will have an award price that is lower than the cheapest fossil fuel-fired power generation option.

**Figure 1.7** The project and global weighted-average LCOE and PPA/auction prices for solar PV, onshore wind, offshore wind and CSP, 2010-2023




*Source: IRENA Renewable Cost and Auction and PPA Databases*

Despite revising the WACC assumptions for this report, there remains a disconnect between the project-level LCOE results and the award prices in the IRENA Auction and PPA database for utility-scale solar PV. This is partly explained by the fact that while the LCOE database covers all new capacity added in 2020, the IRENA Auction and PPA database contains a subset of that total. For instance, the IRENA Auctions and PPA database contains data for 19 GW of projects that are expected to be commissioned in 2021 and for 29 GW of projects expected to be commissioned in 2022. This compares to the estimated utility-scale market of 77 GW in 2020, which is expected to grow in 2021 and 2022.

The distribution of projects in the database is therefore different from the total future deployment, especially so for projects anticipated to be commissioned in 2021, when the projects in the IRENA Auction and PPA is likely to cover less than one-fifth of deployment. Another factor is that the average contract length of 20 years means that for many low-cost solar PV projects, there is a likely merchant tail of revenues that would raise the overall value of the projects by a modest amount. Other factors contributing may include: longer economic lives for the projects than assumed in this report for the LCOE calculations; lower anticipated lifetime O&M costs; and additional revenue streams not captured in the headline award prices.

It is clear, however, that utility-scale solar PV, with the right regulatory and institutional frameworks in place, well-designed contract terms and appropriate risk sharing, can deliver extremely competitive electricity. Indeed, the recent record low auction prices for solar PV in Ethiopia, Chile, Mexico, Peru, Saudi Arabia, the United Arab Emirates and elsewhere have shown that an LCOE of USD 0.03/kWh is possible in a wide variety of national contexts. Expectations are that values below USD 0.02/kWh are potentially feasible in the coming years in specific circumstances, given recent auction results in the United Arab Emirates, Qatar and Saudi Arabia.

The last 18 months has seen three record low bids for solar PV. In January 2020, the Qatar Electricity and Water Corporation (QEWC) announced it had awarded an 800 MW solar PV tender at a price of USD 0.0157/kWh, which was surpassed in April, when the Emirates Water and Electricity Company (EWEC) announced 2 GW of solar PV had been awarded at a levelised price of USD 0.0135/kWh. This record managed to last out 2020, but was then eclipsed by the announcement in April 2021 that Saudi Arabia had awarded the 600 MW Al Shuaiba PV project at USD 0.0104/kWh. Previously, these very low values would have been thought of as unrealistic. Surprisingly, values below USD 0.02/kWh are not impossible, even if they were unthinkable, even a few years ago. They do, however, require almost all factors affecting LCOE to be at their 'best' values (see Box 3.3).

For CSP and offshore wind, deployment is thinner – especially so for CSP, where only 150 MW was added in 2020, compared to 6 GW for offshore wind. As a result, there is significant volatility in the annual global weighted-average values in both the LCOE and IRENA Auction and PPA databases for these two technologies.

For offshore wind, the years 2018 and 2019 saw the announcement of auction and tender results with a step change in pricing. Subsidy-free bids in the Netherlands and Germany, as well as the French Dunkirk project, were awarded at USD 0.05/kWh, while projects in the United Kingdom were awarded at between USD 0.057/kWh and USD 0.06/kWh. This highlighted the fact that with experienced developers, robust regional supply chains and O&M bases, and an attractive cost of capital, offshore wind can now compete with price levels seen in the wholesale electricity market, without financial support.

Offshore wind has longer lead times than onshore wind and solar PV. As a result, these cost reductions take time to appear in annual, newly commissioned cost data. For projects being commissioned from 2023 onwards in Europe, however, the majority of projects that have been procured in the last two years have costs in the USD 0.05/kWh to USD 0.10/kWh range.[12]

By building on experience in onshore wind, technology innovations, supply chain scale-up and learning-by-doing – all while being driven by a cadre of increasingly experienced project developers – Europe's offshore wind industry has been transformed in just 15 years, from one just starting to achieve commercial scale at high costs, to a competitive solution without financial support.

This success is now being exported, with the commissioning of the first round of projects in new markets in North America and Asia also likely to make itself felt in the coming years. With the lessons from Europe around the importance of regional supply chains, installation capability and O&M hubs, we are likely beginning to see how these

12 *There are a number of delayed projects, notably in France, that will come online in the 2021-2024 timeframe that have higher award prices. In the French case, these delays led to downward revisions in the strike prices, though they remain more expensive than recent procurements.*

new markets can rapidly scale up to achieve similarly competitive pricing. The rate at which this happens will be largely driven by the policy ambition that is in place to support economies of scale in regional supply chains. In addition, efforts to facilitate the necessary infrastructure at ports and installation capabilities will also be key drivers.

Meanwhile, the global market for CSP revived somewhat in 2018 and 2019, but disappointed in 2020. The pipeline for CSP projects outside of China remains limited (World Bank, IRENA and CIF, 2021), with little procured competitively in recent years. As a result, there are only a handful of CSP projects in the IRENA Auction and PPA database to be commissioned in 2021, but with a price of electricity of around USD 0.076/kWh, this represents a reduction of 78% compared to the global weighted-average project LCOE in 2010.

## LEARNING CURVES FOR SOLAR AND WIND POWER TECHNOLOGIES

The cost declines experienced from 2010 to 2020 represent a remarkable rate of descent. This not only has enormous implications for the competitiveness of renewable power generation technologies over the medium term, but has also made solar and wind power technologies the economic backbone of the energy transition. These declines also provide important insights into the process of how to successfully deploy the myriad of other technologies required for the energy transition that need to be scaled up over the coming decade. They also provide insights into the characteristics of technologies that are amenable to rapid scale-up and cost reduction[13] in order to ensure decarbonisation of end-use sectors, from electrolysers to electric vehicles and heat pumps to stationary battery storage.

Figure 1.8 shows the global weighted-average total installed cost trends for utility-scale solar PV, CSP, onshore and offshore wind from 2010 to 2020, plotted against deployment. By placing both these variables on a logarithmic scale (log-log), the line on the charts represents the learning rate for these technologies. The learning rate is the average cost reduction (in percentage terms) experienced for every doubling of cumulative installed capacity.

Over the period 2010 to 2020, utility-scale solar PV has the highest estimated learning rate for the global weighted-average total installed cost, at 34%. This is a value that exceeds virtually all previous learning rate analyses based on data for the earlier period of deployment (Grubb, *et al.*, 2021) – when learning rates might have been expected to be higher than in later periods. This period, 2010 to 2020, saw the deployment of 94% of global cumulative installed solar PV capacity and virtually all of the utility-scale deployment, in capacity terms.

The learning rate for the total installed costs of CSP for the period 2010 to 2019 was 22%, with 80% of total cumulative installed CSP capacity added during this period.

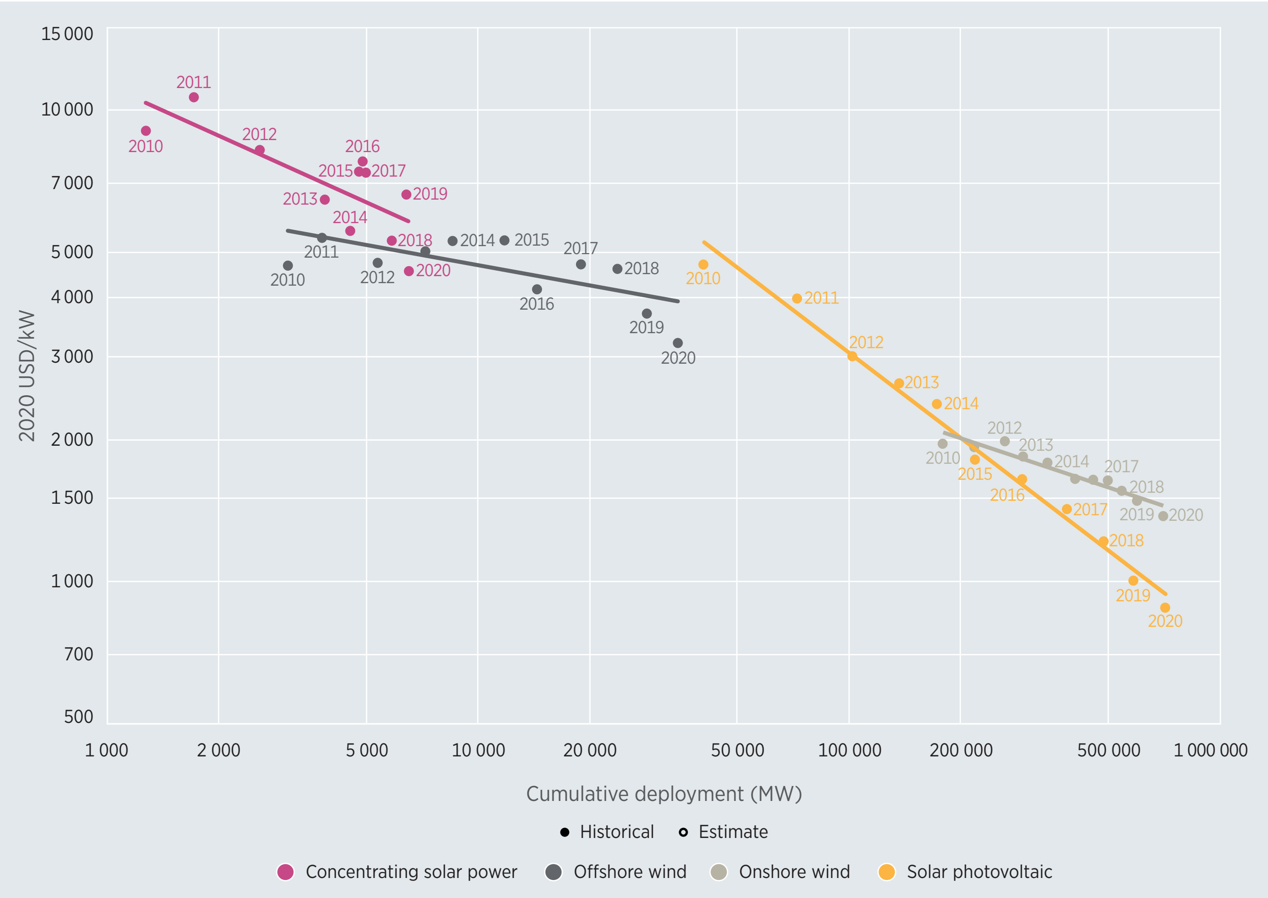
The total installed cost learning rate for offshore wind for the period 2010 to 2020 is estimated to have been 9.4%, with new capacity additions over this period estimated to be 91% of the cumulative installed offshore wind capacity.

*13 Future work by IRENA will look at what lessons can be extracted from the data IRENA is collecting in the "Tracking Energy Innovation Outputs Framework" in respect to solar and wind, in order to identify the elements of successful deployment that are transferable and where more caution is required for different technologies.*

For onshore wind, the total installed cost learning rate for the period 2010 to 2020 is estimated to be 16.6%. The decline in wind turbine prices in recent years, as well as greater regional supply chain maturity and competitive procurement of projects, has contributed to lower costs in recent years. For the total installed cost of onshore wind farms, the learning rate for the period 1983 to 2020, is estimated to be 8.5%. The difference between the learning rates for the two time periods is significant. It poses interesting questions about the relative contribution made by early market research and development (R&D) learning – compared to ongoing innovation and industrial scale-up – in driving down costs.[14]

With the highest learning rate for total installed costs, it is not surprising to find that for the period 2010-2020, utility-scale solar PV also exhibited the highest LCOE learning rate, at 39% (Figure 1.9). Utility-scale solar PV is also the technology to have the highest proportion of the LCOE learning rate driven by declines in total installed costs, given there is little difference between the LCOE learning rate and the total installed cost learning rate of 34%. The LCOE learning rate for CSP for the period 2010 to 2020 was significantly higher than the learning rate for total installed costs (which was 22%) and is estimated to have been 36%. The main difference when compared to solar PV was the significant contribution to lower LCOE values from CSP due to the growth in capacity factors – from 30% to 42% – between 2010 and 2020.

**Figure 1.8** The global weighted-average total installed cost learning curve trends for solar PV, CSP, onshore and offshore wind, 2010-2020



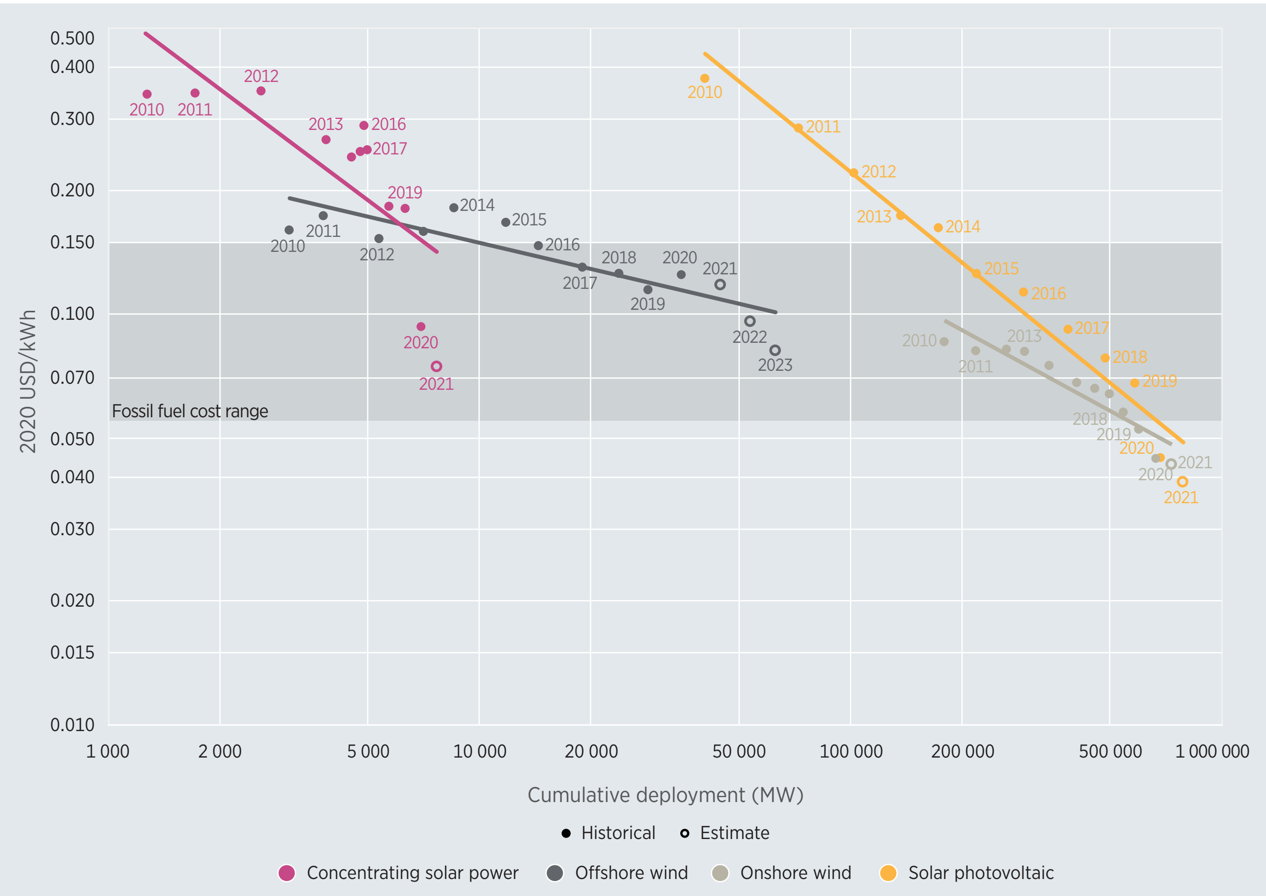

*Source: IRENA Renewable Cost Database*

*14 IRENA has not yet investigated this, but see Elia, A; et al. (2020) for the discussion of a potential methodological approach to investigating the relative contribution of different drivers of the learning for wind turbines.*

For onshore wind, the LCOE learning rate for the period 2010 to 2019 was 32% – slightly less than twice that for total installed costs alone. Again, the higher learning rate is due to important growth in capacity factors, which rose from a global weighted-average of 27% in 2010 to 36% in 2020. Reductions in O&M costs contributed somewhat less compared to CSP, while the assumed WACC reduction also played a role. The LCOE learning rate for offshore wind for the period 2010 to 2020 reached 15%, influenced heavily by the period 2010 to 2015, when installed costs were higher than the starting value in 2010. In this respect, the learning curve data makes clear how recent and rapid the cost reductions have been for offshore wind.

These learning rates represent remarkable rates of cost deflation, with the very low absolute levels being achieved increasingly changing the outlook for what is possible in the energy transition. Caution should be used in interpreting the LCOE learning rates, however, as – at least in part – some of the cost reductions achieved in the last ten years will not continue at the same rate. This is clear for WACC reductions, as risk premiums for renewables for equity and debt are already very low in mature markets. This may also be true for O&M cost reductions. Many of these caveats don't apply to the learning rates for total installed costs. Clearly, year-to-year volatility in deployment and equipment prices can have an influence on short-term results, but the learning rates for total installed costs give a strong indicator of the likely, near-term (3-5 years),

**Figure 1.9** The global weighted-average LCOE learning curve trends for solar PV, CSP, onshore and offshore wind, 2010-2021/23




*Source: IRENA Renewable Cost Database*

learning rates and can be used to help predict future cost reductions. In addition to this, the learning rate analysis here has some important implications for the energy transition. The learning rate analysis here and by others, highlights that when scaled, small, modular technologies with lower barriers to market entry and relatively simple and replicable project development and installation processes can achieve sustained, high rates of learning-by-doing. Future work by IRENA will look at using this analysis, and the more detailed metrics currently being collected in the Tracking Energy Innovation Framework project, to identify the applicability of the lessons from the high learning rates achieved by solar and wind technologies to other technologies needed in the energy transition.

### Solar PV, onshore and offshore wind cost reductions are increasingly stranding coal-fired power plants

As costs for solar PV and onshore wind have fallen, new renewable capacity is not just increasingly cheaper than new fossil fuel-fired capacity, but increasingly undercuts existing coal-fired power plants' operating costs. Yet, while the most obvious contributor to this dynamic is the continued falling costs of solar and wind power technologies, there is also a self-reinforcing dynamic at play when it comes to the declining competitiveness of existing fossil fuel-fired power plants. As solar and wind power costs have fallen, capacity additions have grown, reducing annual running hours for coal-fired power plants in many countries. For instance, between 2010 and 2020, the average capacity factor of Indian coal plants dropped from 78% to 53%.[15] In the United States, they fell from around 65% in 2010 to between 38% and 41% in 2020. This was despite the US coal fleet declining by almost a third, from a peak of 318 GW in 2011 to 216 GW at the end of 2020.[16]

Given that coal-fired power plants have significant fixed O&M costs, reduced generation starts to significantly raise operating costs, further worsening the competitiveness of these coal plants. For instance, over its lifetime, a 1 GW coal plant in the United States might expect to average fixed costs of around USD 60/kW/year, with around USD 34/kW/year for O&M and USD 26/kW/year for additional major capital expenditure (Sargent & Lundy, 2019). At a capacity factor of 10%, fixed costs alone amount to around USD 0.068/kWh, while at a 20% capacity factor, they are USD 0.034/kWh and at 40% are USD 0.017/kWh. This is before considering fuel and variable O&M costs.

With new renewables, energy efficiency and, in some regions, natural gas all reducing existing coal-fired power plants' capacity factors, these higher costs look set to be the norm. This is against a background where aging coal plants in many countries are facing expensive refurbishments to continue reliable operation. Many of these facilities will also increasingly face major investment decisions in a climate where future revenues are unlikely to justify continued operation.[17]

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15 *Based on data from the National Power Portal. See https://npp.gov.in/monthlyGenerationReportsAct (accessed 20 May 2021).*

16 *See the United States Energy Information Administration Form EIA-860 data and "U.S. coal-fired electricity generation in 2019 falls to 42-year low" article at www.eia.gov/todayinenergy/detail.php?id=43675# (accessed 20 May 2021). The value of 41% capacity factor is based on net summer capacity and the figure of 38% on nameplate capacity. The nameplate capacity is the capacity most comparable to the data presented in this report, and the summer capacity for operational system planning. Net winter capacity is also reported, given that the United States has states that are either winter or summer peaking. There is only a 0.4% difference between the winter and summer values.*

17 *Between 20 and 30 years after initial operation, coal-fired power plants need to replace a wide array of worn out parts in the boiler system (e.g., superheater and re-heater headers, feedwater supply piping, coal feeders, mill motors, etc.), the turbine and generator (e.g., turbine blades, stop valves, generator stator, etc.) and in the balance of plant (Sargent & Lundy, 2019).*

The current costs of operating existing lignite and hard coal-fired power plants are presented in Figure 1.10 for plants in Bulgaria (lignite plants only), Germany, India and the United States. To the extent possible, the data for the calculation of operating costs have been updated to reflect the plant-level capacity factors in 2020 and the current costs of fuel[18] (see Annex I for more details).[19] The figure also includes the weighted-average PPA price for projects to be commissioned in 2021 in each country, or in the case of Bulgaria, an estimate of the LCOE of solar and onshore wind – representative for South East Europe – based on projects currently in development.[20]

None of the large German and Bulgarian hard coal and lignite plants are likely to have operating costs in 2021 that are lower than adding new utility-scale solar PV or onshore wind, assuming European Emissions Trading Scheme (ETS) permits average EUR 50/tonne of $CO_2$ (USD 60/tonne $CO_2$) in 2021. The operating costs for existing coal-fired power plants in the United States and India are, on average, lower than in Europe, given the absence of meaningful carbon pricing in these markets. However, solar PV and onshore wind costs are also lower, meaning that in the United States, 77%-91% of the existing coal-fired capacity has operating costs that are higher than the cost of new solar or wind power capacity, while in India, the figure is 87%-91%.

*18 For mine-mouth coal-fired power plants this reflects mining costs plus infrastructure for conveying coal to the power plant. For other plants, it represents the delivered fuel price from distant coalfields or seaborne trade. Landed coal future prices for the second-half of 2021 were, at the time of writing, averaging around USD 90/tonne for landed (CIF) thermal coal Amsterdam-Rotterdam-Antwerp, which is significantly higher than the average of around USD 50/tonne in 2020 (CME Group, 2021).*

*19 This analysis is predominantly based on updating the following sources: Carbon Tracker, 2018; Szabó, L., et al., 2020; Öko-Institut, 2017; DIW Berlin, Wuppertal Institut and EcoLogic, 2019; and Vibrant Clean Energy, 2019. The updates draw on a number of sources, including Booz&Co, 2014; Coal India, 2020; Energy-charts.de, 2021; IEA, 2021; NPP, 2021; and US EIA, 2021.*

*20 The assumptions for solar PV are EUR 740/kW (USD 830/kW) and a capacity factor of 13%, while for wind, the assumptions are EUR 1 500/kW (USD 1 685/kW) and a 36% capacity factor.*

**Figure 1.10** Operating costs only of existing coal-fired power plants in Bulgaria, Germany, India and the United States by installed capacity and capacity factor in 2020


*Source: Booz&Co, 2014; Carbon Tracker, 2018; Coal India, 2020; DIW Berlin, Wuppertal Institut and EcoLogic, 2019; IEA, 2021; Öko-Institut, 2017; Energy-charts.de, 2021; Gimon, et al., 2019; NPP, 2021; US EIA, 2021; Szabó, L.,* et al., *2020 and IRENA Renewable Cost Database.*

*Note: The totals for the United States include plants that are partially or fully capable of being duel fired on natural gas. Where generation on natural gas occurred in 2020, this is added to total generation used for calculating the fixed costs per megawatt hour in this chart, to take into account the improved economics of these plants.*

*Operating costs analysed include: 1) average lifetime fixed and variable O&M costs 2) average lifetime capital expenditures required to maintain reliable operation and meet air quality regulations 3) fuel costs for 2020/21 (delivered) 4) $CO_2$, emission costs, where applicable.*

Despite lower operating costs, the competitiveness of existing coal-fired power plants in India and the United States remains precarious. With solar resources that are good-to-excellent in both countries, the 2021 weighted-average solar PV auction and PPA prices are very competitive, at around USD 33/MWh in India and USD 31/MWh in the United States. In the latter country, however, much depends on the location of deployment, given higher installed costs in California and on the East Coast. Both countries onshore wind auction and PPA prices for projects commissioning this year are competitive, at around USD 32/MWh in India and USD 37/MWh in the United States. The challenge that apportioning high fixed costs over ever-declining generation is brought into sharp relief in the United States, where, of the power plants analysed, 73% had annual capacity factors of less than 50%.

The data presented here is indicative of the size of the opportunity that exists to accelerate the energy transition by retiring high-cost coal plants and replacing them with renewables. Assuming an average cost of USD 5/MWh for integration costs, Table 1.1 summarises the analysis for the four countries presented for 2021 in detail, as well as the results for the rest of the world.

In total, over 800 GW of existing coal-fired electricity generation may have costs higher than new solar PV or onshore wind for commissioning in 2020, including an additional USD 5/MWh for integration costs. Retiring these plants would reduce electricity generation costs by around USD 32 billion per year and avoid around 3 gigatonnes (GT) of $CO_2$ per year. Around 40% of the total capacity and 37% of the generation that has costs higher than new renewables (including variable renewable integration costs) is in the four countries analysed in more detail in Figure 1.7.

In the United States, 149 GW (61% of the capacity analysed) has higher operating costs than new renewable capacity, in India the total is 141 GW (65%). In India, in addition to the direct economic benefits, there would be significant benefits from reduced outdoor air pollution, which is currently estimated to result in 980 000 premature deaths per year in India. Such a reduction in pollution levels might reduce by over half the total economic costs of premature deaths, which stands at USD 28.8 billion per year (Pandey *et al.*, 2020).

**Table 1.1** Capacity of uneconomic existing coal-fired power plants and annual savings in coal-fired generation, electricity costs and $CO_2$ emissions, 2021

| | Coal capacity with higher operating costs than new solar and wind | Capacity with higher costs than renewables + USD 5/MWh integration costs | Annual savings from replacing uncompetitive coal with new solar and wind | Reduction in coal generation | Annual $CO_2$ emissions reductions |
|---|---|---|---|---|---|
| | (GW) | (GW) | (USD billion/year) | (TWh) | (Mt $CO_2$/year) |
| Bulgaria | 3.7 | 3.7 | 0.7 | 18 | 18 |
| Germany | 28 | 28 | 3.3 | 97 | 99 |
| India | 193 | 141 | 6.4 | 676 | 643 |
| United States | 188 | 149 | 5.6 | 338 | 332 |
| Rest of the world | 724 | 488 | 16.3 | 2 222 | 1 881 |
| **World** | **1 137** | **810** | **32** | **3 351** | **2 973** |

*Source: IRENA analysis based on Carbon Tracker, 2018; Szabó, L., et al., 2020; IEA, 2021; Öko-Institut, 2017; Booz&Co, 2014; Energy-charts.de; DIW Berlin, Wuppertal Institut and EcoLogic, 2019; Gimon, et al., 2019; US EIA, 2021; and IRENA Renewable Cost Database*

*Note: Annual cost savings, reduction in coal generation and avoided $CO_2$ emissions are for retiring the amount of coal that is uneconomic including the allowance for USD 5/MWh for integration costs.*

**Box 1.1** **Deriving country- and technology-specific WACC values**

Having more accurate WACC assumptions not only improves the advice IRENA can give its member countries, but also fills a gap for the broader energy modelling community. This is in critical need of improved renewable energy cost of capital data (Egli, Steffen and Schmidt, 2019). Changes in the cost of capital between countries or technologies are not properly accounted for over time can result in significant misrepresentations of the LCOE, leading to distorted policy recommendations.

Today, however, reliable data encompassing multiple world regions, renewable technologies and time periods remains sparse (Donovan and Nunez, 2012), due to the proprietary nature of financial data (Steffen, 2019). Existing studies can provide useful snapshots for individual countries or technologies, but it can be challenging to extract meaningful insights from these, as the majority of studies to date use inconsistent methodologies and may refer to different years, countries and technologies.

In November 2019, IRENA conducted a workshop with experts in the field to discuss these issues and current WACC assumptions, in order to identify a way to improve data availability. The result of this workshop was a plan for IRENA, IEA Wind and ETH Zurich to work together to fill this knowledge gap via a three-pronged approach that would develop: 1) a benchmark cost of finance tool, informed by 2) an online survey of stakeholders with knowledge financing conditions; and 3) semi-structured interviews with a number of experts. The goal of this work is to arrive at detailed country and technology-specific WACC data for solar PV, onshore and offshore wind.

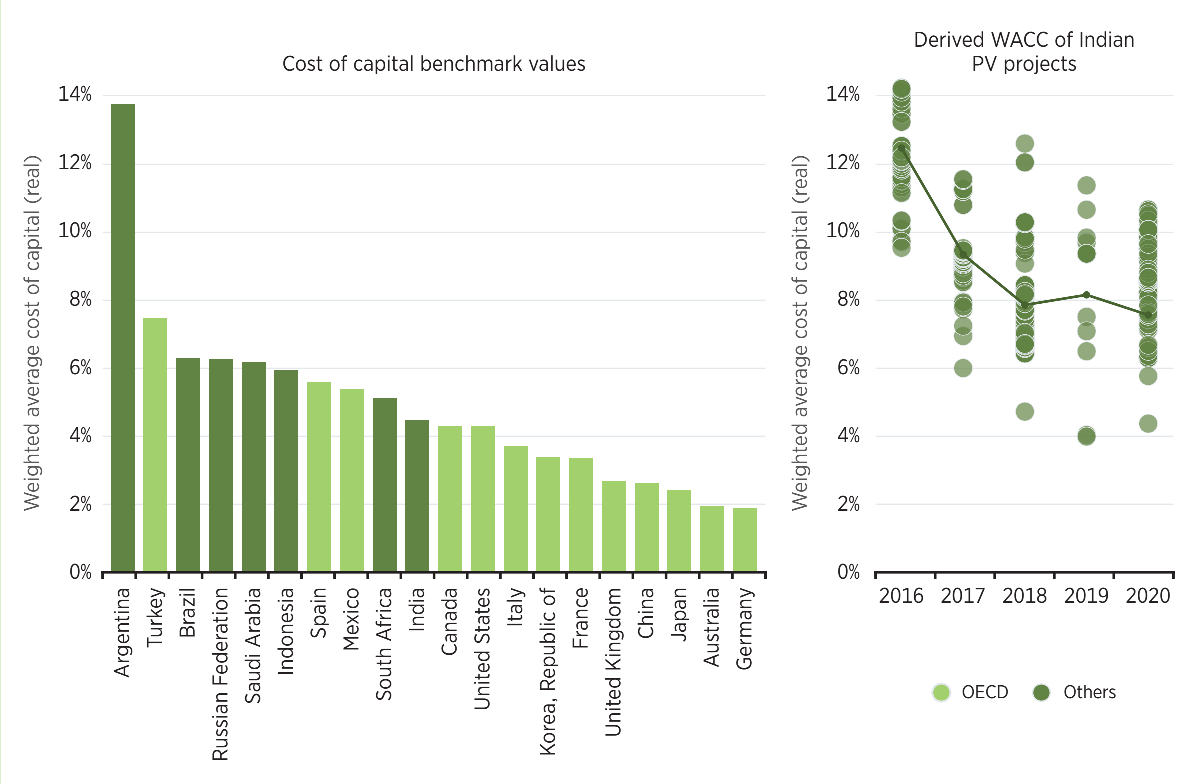
The benchmark cost of capital tool is designed to identify assumptions for WACC components (*e.g.,* debt cost, equity cost, debt-to-equity ratio, etc.) and yield country- and technology-specific WACC values. The benchmark tool will be calibrated based on the survey results, but will also be used to fill in gaps in the survey analysis.[21]

The left of Figure B1.1 provides a snapshot of financing conditions for an investment decision in 2021 for utility-scale solar PV from the benchmark tool as it currently stands, prior to calibration with the survey results. The benchmark values for utility-scale solar PV range from a low of around 2% in real terms – in Germany and Australia – to around 6% in countries such as Brazil.

Leaving aside the accuracy of the benchmark tool approach *per se*, it is important to note that in markets where financing conditions are changing, this rate may not be a good indicator of the financing conditions faced by a plant commissioned today, which may have reached financial close a year or more ago. This is where the second part of the benchmarking work becomes useful. IRENA and ETH Zurich worked together to match utility-scale solar PV projects in the IRENA Renewable Cost Database and IRENA Auctions and PPA Database with project-level total installed costs and capacity factors, country O&M values and standardised economic lifetimes. We then arrived at a WACC that yielded an LCOE that matched the adjusted PPA/auction price.

*21 It is not feasible for survey stakeholders' project partners to provide real-world WACC components for solar PV, onshore and offshore wind in even a majority of the countries of the world. Therefore, the benchmark cost of capital tool will be essential in fleshing out gaps in the survey results to provide climate and energy modellers with data for all the countries/regions in their models.*

**Figure B1.1** Benchmark real WACC estimates for utility-scale solar PV projects in the G20, 2021




*Source: (Left side) Analysis by ETH Zurich, IEA Wind Task 26 and IRENA (Right side) IRENA Renewable Cost Database and Orgland,2021*

The data for these reverse engineered WACC values for Indian solar PV projects commissioned between 2016 and 2020 are presented on the right of Figure 1.11. India provides a good example of a major solar PV market, where competitive procurement has been extensively used and good project-level cost and performance data is available. The values for India align quite well with our previous assumption of 10% WACC, at least for projects commissioned in 2017, but are higher for the earliest projects that came online in 2016 and were financed in the first rounds of growth in India's PV deployment in 2014 and earlier. The data for 2020 suggests a figure of 7.5% is not unreasonable, as WACC values have clearly trended downwards, over time. In general, the results of this analysis have also yielded values that broadly validate the cost of capital benchmark tool if the financing conditions for the 2018/19 (the likely years where the 2020 projects were financed) and align with other estimates of country and technology-specific WACC (see for instance, Egli F. *et al.,* 2018 and Steffen, 2019).

Next year's report will benefit from a fully calibrated and reviewed benchmark cost of capital tool and the results of the cost of finance survey and semi-structured interviews, to create a database of WACC assumptions that is differentiated by country and technology for all countries present in the IRENA Renewable Cost Database (a total of 166 countries at this time).

## LOW-COST RENEWABLE HYDROGEN TODAY: IS IT POSSIBLE?

In what has been a remarkable decade, the combination of targeted policy support and industry drive has seen renewable electricity from solar and wind power go from an expensive niche, to head-to-head competition with fossil fuels for new capacity. In the process, it has become clear that renewables will become the backbone of the electricity system and help decarbonise electricity generation, with costs lower than a business-as-usual future.

The last couple of years have also shown that even this achievement might soon be surpassed.

*Hydrogen could potentially be produced for as little as USD 1.62/kg $H_2$ in Saudi Arabia today, given current solar PV and onshore wind costs*

The emergence of exceptionally low cost electricity from solar PV in areas with excellent solar resources and access to low-cost finance, as well as low-cost onshore wind, represent a potentially tectonic shift in not just the electricity generation sector, but the energy system as a whole.

It is the potential to produce competitive, renewable hydrogen from very low-cost solar PV and onshore wind in the sunbelt that has, perhaps, provided the key to unlocking the final part of the puzzle of an affordable 1.5°C pathway (IRENA, 2021b).

Indeed, with an economic route to decarbonising the electricity sector presented by low-cost solar, wind and battery storage, electrification is now one of the key pillars of achieving that 1.5°C pathway (IRENA, 2021b).

It had often been presumed, however, that indirect decarbonisation with electricity through renewable hydrogen and synthetic fuels and chemicals would be expensive and take some time to drive down costs.

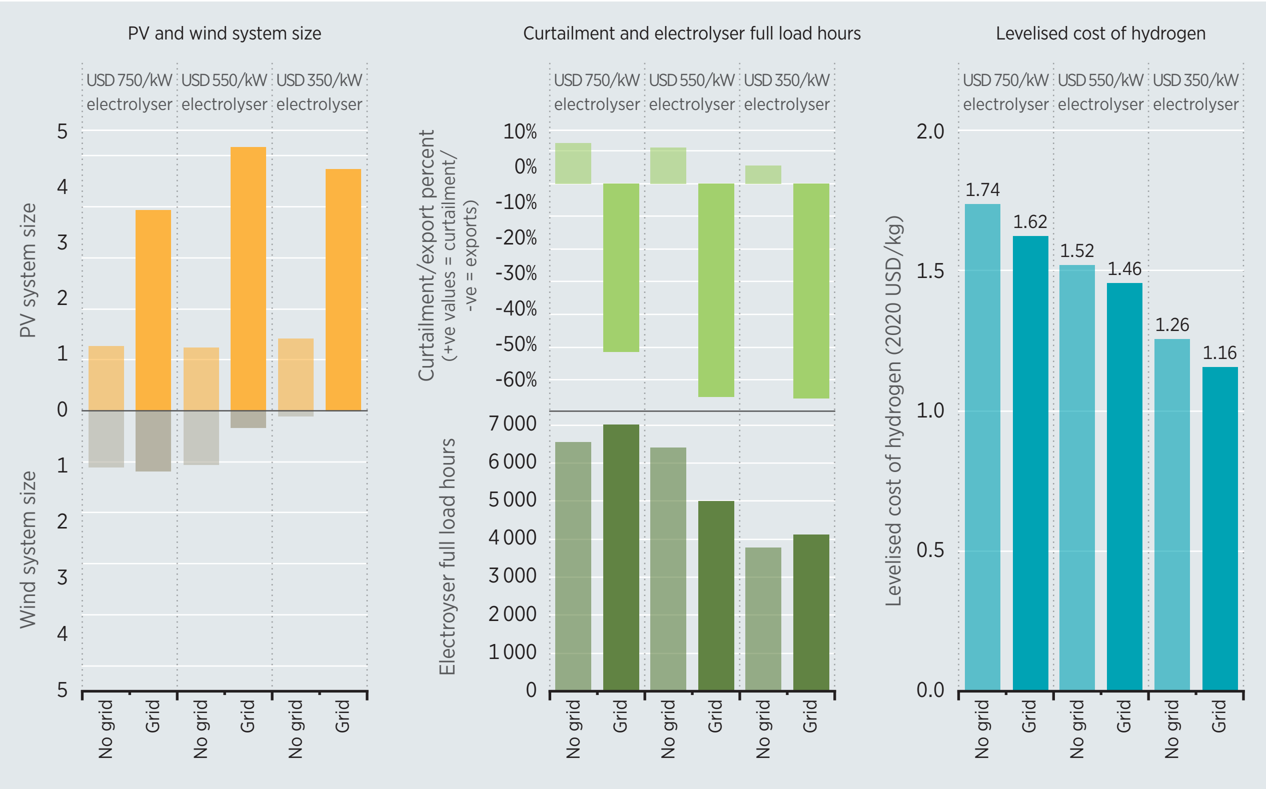
The key barrier to affordable renewable hydrogen had been thought to be a combination of two factors: first, the high cost of renewable electricity with low load hours on the electrolyser, due to low renewable solar and wind capacity factors; and second, the high capital costs of hydrogen electrolysers that would necessitate high load hours from renewables in order to generate low-cost hydrogen. These are no longer insurmountable hurdles, however. Very low-cost solar PV now appears to be feasible. At the same time, low-cost onshore wind is also possible. Saudi Arabia awarded EDF and Masdar the contract for the 400 MW Dumat al Jandal wind farm in January 2019 at a price of USD 0.0213/kWh, although this fell to USD 0.0199/kWh at financial close.[22]

22 See https://www.edf-renouvelables.com/en/middle-easts-largest-wind-farm-in-the-kingdom-of-saudi-arabia-reaches-halfway-mark-on-construction/ for details (accessed on 6 June 2021).

Figure 1.11 presents the results of an optimisation for the co-location of a solar PV, onshore wind and electrolyser in Saudi Arabia in the vicinity of the Dumat al Jandal wind farm, where excellent solar and wind resources combine – although water costs will be higher than in less arid areas. In addition to a scenario with today's electrolyser costs, two lower cost scenarios are also examined. Across all scenarios, we examine two variants: a stand-alone system that is islanded; and a grid-connected one where the facility can potentially sell to the grid (which, to be conservative, is to be at the lower end of the two PPA prices), but does not purchase from the grid for hydrogen production.[23]

The potential levelised cost of hydrogen (LCOH$_2$) in Saudi Arabia with the cost of solar PV and onshore wind available today, could be as little as USD 1.62/kilogramme of hydrogen (kg $H_2$), if a hydrogen production facility could sell its surplus electricity into the grid for USD 0.0104/kWh – and USD 1.74/kg $H_2$, if it could not.

**Figure 1.11** Scenarios for LCOH$_2$ from utility-scale solar PV and onshore wind under different input assumptions in Saudi Arabia




*Source: IRENA*

*Note: Wind and system sizes are scaled to the hydrogen electrolyser capacity. So a system size of 1.5 for solar PV and 1.5 for wind would mean a 100 MW electrolyser was being fed by 150 MW each of solar PV and onshore wind.*

*Assumptions: USD 750/kW for an alkaline electrolyser system; 65% efficiency; a 15 year stack life (with a maximum of 80 000 hours of operation and stack replacement allowed for); 3% of capital expenditure (CAPEX) for the electrolyser O&M costs; the LCOE values from the Al Shuaiba PV and Dumat al Jandal wind farm; and the same implied real WACC of 1.9% from the PV project to amortise the electrolyser.*

*23 The economic model solves for the minimum LCOH$_2$ value by varying solar PV, onshore wind and battery storage capacity sizes relative to the electrolyser electrical input capacity. It factors in hourly generation profiles at the site for single-axis tracking for solar PV and the generation from Vestas V150 4.2 MW wind turbines. The battery capital costs were assumed to be a low, USD 125/kWh, but take-up was below the margin of error, so is not discussed in the main body of the text.*

These figures compare favourably with the hypothetical cost of natural gas steam methane reforming, with today's carbon capture, utilisation and storage (CCUS) costs at between USD 1.45/kg $H_2$ and USD 2.4/kg $H_2$ (IEA, 2020).

With electrolyser costs of USD 750/kW, amortising that investment by running the plant as much as possible is part of the economic solution. In an islanded system, full load hours of around 6 560 are achieved with a close balance between the optimum solar and wind capacity, with curtailment of around 12%. The electrolyser is therefore running for around 75% of the year at full capacity, despite very low electricity input costs. When a grid connection can be factored in, the optimal solution is to ensure the electrolyser runs on as much of the cheapest source of electricity as possible. The complementarity of solar and wind becomes less important, but is still there – as can be seen by the slight increase in wind capacity and full load hours, which rise to 7 020 hours. Solar PV capacity jumps dramatically, however, and exports to the grid are slightly higher than the electrolyser consumption over the year (*e.g.,* total electricity production is just over twice electrolyser consumption).

As can be seen in Figure 1.12, as the electrolyser cost starts to fall, the importance of running at very high load hours weakens. With electrolyser costs of USD 550/kW, this phenomenon has a limited impact on the islanded system, with full load hours dropping from around 6 560 to 6 410 hours, as slightly less wind is used. It is more pronounced, however, when over-sizing the cheapest electricity source, solar PV, becomes available with a grid connection. In this case, wind input to the electrolyser is reduced to 25%, with overall full load hours dropping to around 5 000 hours, as the optimal solution is to use more of the cheapest, solar, electricity.

When electrolysers reach a cost of just USD 350/kW, the economic optimum shifts significantly. With a low contribution from electrolyser capital costs, maximising the source of low-cost electricity becomes the priority. In Saudi Arabia, with excellent solar resources, this trend is very pronounced. There, even an islanded system essentially finds an economic optimum with 93% solar PV. Curtailment remains a modest 5%, as the PV system is oversized by around 43%, with the corresponding reduction in full load hours to 3 790 being acceptable. When the option to sell to the grid is added, the sizing of the solar PV capacity increases dramatically, as do exports to the grid. The analysis suggests that with electrolyser costs of USD 350/kW, costs could fall as low as USD 1.16/kg $H_2$. Assuming average efficiency also increases to 72.5% over that time and stack lifetime increases from 15 to 17.5, costs would fall below USD 1/kg $H_2$. This does not even take into account any possible reduction in the cost of electricity from solar and wind, by the time those performance and cost levels for electrolysers are reached.

This analysis demonstrates two important points. First, that competitive renewable hydrogen in specific markets could be available even before significant cost reductions and performance improvements in electrolysers have materialised. Secondly, low-cost hydrogen from solar and wind may initially rely on areas with excellent solar and wind resources, given the need to achieve high load hours to amortise the costs of relatively expensive electrolysers. In the medium- to long-term, however, cost reductions and performance improvements for electrolysers will start to see this dynamic shift to prioritising areas with very low-cost electricityand even to solar PV with, its relatively low, capacity factor. This has important implications for the extent of the resource base for low-cost hydrogen, as areas with excellent resources for either solar or wind are much more widely distributed than those that combine both.

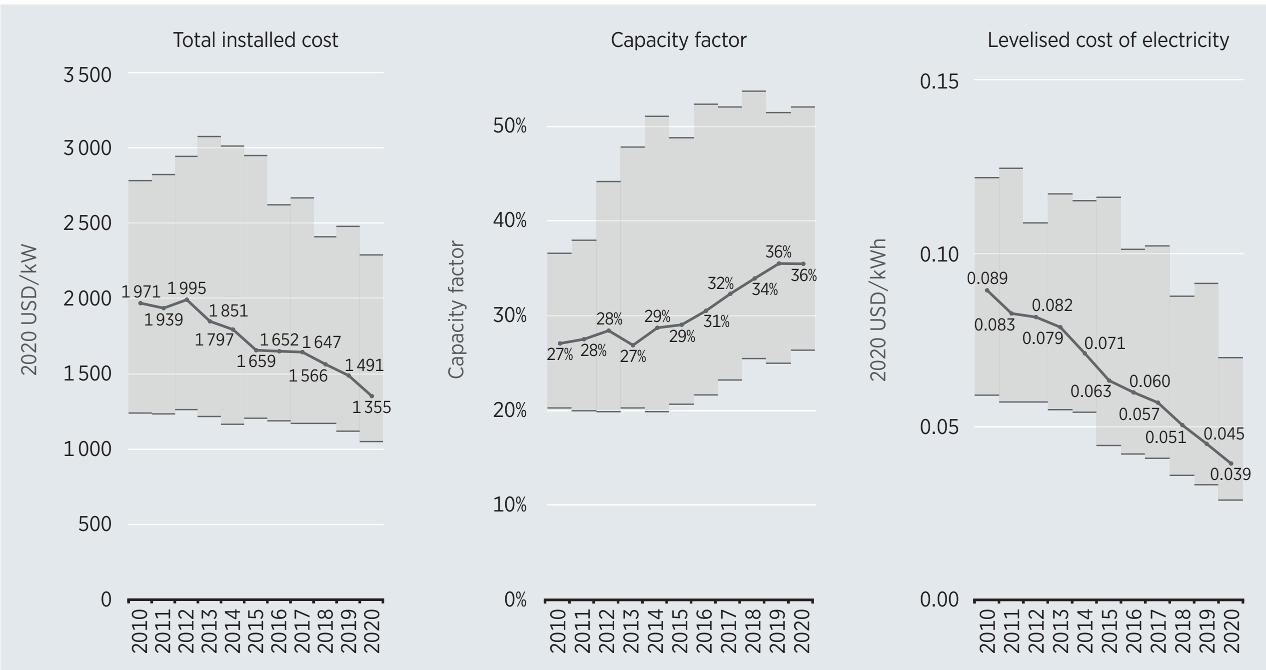
02

# ONSHORE WIND

## HIGHLIGHTS

- The global weighted-average LCOE of onshore wind fell 56% between 2010 and 2020 from USD 0.089/kWh in 2010 to USD 0.039/kWh in 2020. There was a 13% year-on-year reduction in 2020.
- In 2020, around 100 gigawatts (GW) of the new onshore wind projects commissioned had an LCOE lower than the cheapest new source of fossil fuel-fired power generation.
- The cumulative capacity of onshore wind has increased almost fourfold during the past decade, from 178 GW in 2010 to 699 GW in 2020.
- The global weighted-average total installed cost has fallen by 31%, from USD 1971/kW in 2010 to USD 1355/kW in 2020, when it was down 9% on the 2019 value of USD 1491/kW.
- The country/region weighted-average total installed cost for onshore wind in 2020 ranged from around USD 1038-3189/kW. China and India have weighted-average total installed costs between 20% to 67% lower than other regions.
- Average turbine prices were between USD 700/kW and USD 910/kW in 2020. Prices in most regions, excluding China, have fallen by between 49% and 59% from their peaks in 2008 and 2009. Chinese wind turbine prices have fallen 78% since their peak in 1998 of USD 2520/kW to USD 540/kW.
- Technology improvements have resulted in an almost one-third improvement in the global weighted-average capacity factor, from 27% in 2010 to 36% in 2020.

**Figure 2.1** Global weighted-average total installed costs, capacity factors and LCOE for onshore wind, 2010-2020




*Source: IRENA Renewable Cost Database.*

# INTRODUCTION

Onshore wind turbine technology has advanced significantly over the past decade. Larger and more reliable turbines, along with higher hub-heights and larger rotor diameters, have combined to increase capacity factors. In addition to these technology improvements, total installed costs, operation and maintenance (O&M) costs, and LCOEs have been falling as a result of economies of scale, increased competitiveness and maturity of the sector. In 2020, onshore wind deployment was second only to solar photovoltaic (PV) and significantly higher than in 2019 due to a surge in projects commissioned in China.

Today, virtually all onshore wind turbines are horizontal axis turbines, predominantly using three blades and with the blades "upwind". The largest share of the total installed cost of a wind project is related to the wind turbines. Contracts for these typically include the towers, installation and delivery – except in China. Wind turbines now make up between 64% and 84% of the total installed costs of an onshore wind project (IRENA, 2018). The other major cost categories include installation, grid connection and development costs. The latter includes environmental impact assessment and other planning requirement costs, project costs, and land costs – with these representing the smallest share of total installed cost.

## Wind turbine characteristics and costs

Wind turbine original equipment manufacturers (OEMs) offer a wide range of designs, catering for different site characteristics,[1] grid accessibility and policy requirements in distinct locations. These variations may also include different land-use and transportation requirements, and the particular technical and commercial requirements of the developer. OEM's use of a series of "platforms" that offer different configurations suited to individual site characteristics has been an important driver of cost reductions, both installed costs, in amortising product development costs over a larger number of turbines and in optimising turbine selection for a site, to minimise LCOE.

Turbines with larger rotor diameters increase energy capture[2] at sites with the same wind speed, and this is especially useful in exploiting marginal locations. In addition, the higher hub-heights that have become common enable higher wind speeds to be accessed at the same location, while also increasing the range of suitable locations for wind turbines (*e.g.,* in forests due to the larger separation of blade tips from the ground). This can yield materially higher capacity factors, given that power output increases as a cubic function of wind speed. The higher turbine capacity also enables larger projects to be deployed and reduces the total installed cost per unit for some cost components (expressed in megawatts [MW]).[3]

Figure 2.2 illustrates the evolution in average turbine rating and rotor diameter between 2010 and 2020 in some major onshore wind markets. Brazil, Canada and Sweden stand out, with increases of greater than 50% in both the average rotor diameter and turbine capacity of their commissioned projects, between 2010 and 2020. In percentage terms, the largest increase in turbine capacity was observed in Sweden (113%) followed by Brazil (105%) and Canada (101%). The largest increase in rotor diameter occurred in Canada (108%)

*1 Wind speeds, area for adequate spacing to reduce wake turbulence, and turbulence inducing terrain features.*

*2 Energy output increases as a squared function of the surface area, which is a key variable in the power output of a wind turbine.*

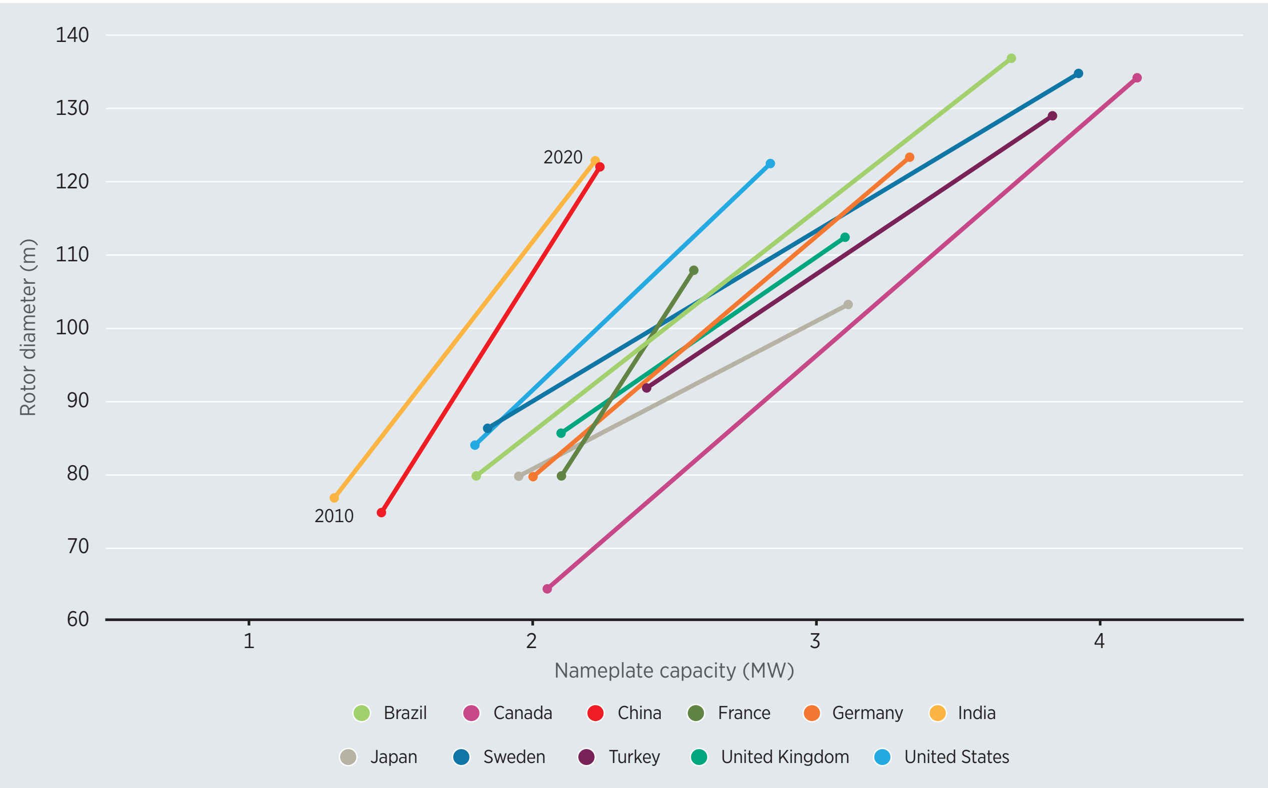
*3 Increasing turbine size does not lead to a proportional increase in the cost of other turbine components, e.g., towers, bearings, nacelle, etc. Thus, the increase in cost on a per unit basis is not as significant as might be expected.*

followed by Brazil (71%) and China (63%). Of the countries covered in Figure 2.2, Canada and Brazil had the largest turbine rating and rotor diameters, respectively, on average in 2020. In 2020, India had the lowest turbine rating and the Japan had the lowest rotor diameter. Overall, in 2020 the country-level average turbine capacity ranged from 2.22 MW to 4.13 MW, and rotor diameter from 103 meters (m) to 134 m.

Wind turbine prices reached their previous low between 2000 and 2002, with this followed by a sharp increase in prices. This was attributed to increases in commodity prices (particularly cement, copper, iron and steel), supply chain bottlenecks and improvements in turbine design, with larger and more efficient models introduced into the market. However, due to increased government renewable energy policy support for wind deployment, this period also coincided with a significant mismatch between high demand and tight supply, which enabled significantly higher margins for OEMs during this period.

As the supply chain became deeper and more competitive and manufacturing capacity grew, these supply constraints eased and wind turbine prices peaked. Most markets experienced a peak between 2007 and 2010 and fell by between 44% and 78% by the end of 2020. Prices were in the range USD 700/kW to USD 910/kW in 2020 in most major markets, excluding China (Figure 2.3). The experience in China was one of a dramatic price fall from 1998 – when the wind turbine price was around USD 2 520/kW – to 2002. Prices then declined in an irregular, step-wise fashion to the point where the 2020 price was around an average of USD 540/kW, somewhat above 2019 levels due to tight supply given the surge in deployment in 2020.[4]

**Figure 2.2** Weighted-average osnhore wind rotor diameter and nameplate capacity evolution, 2010-2020



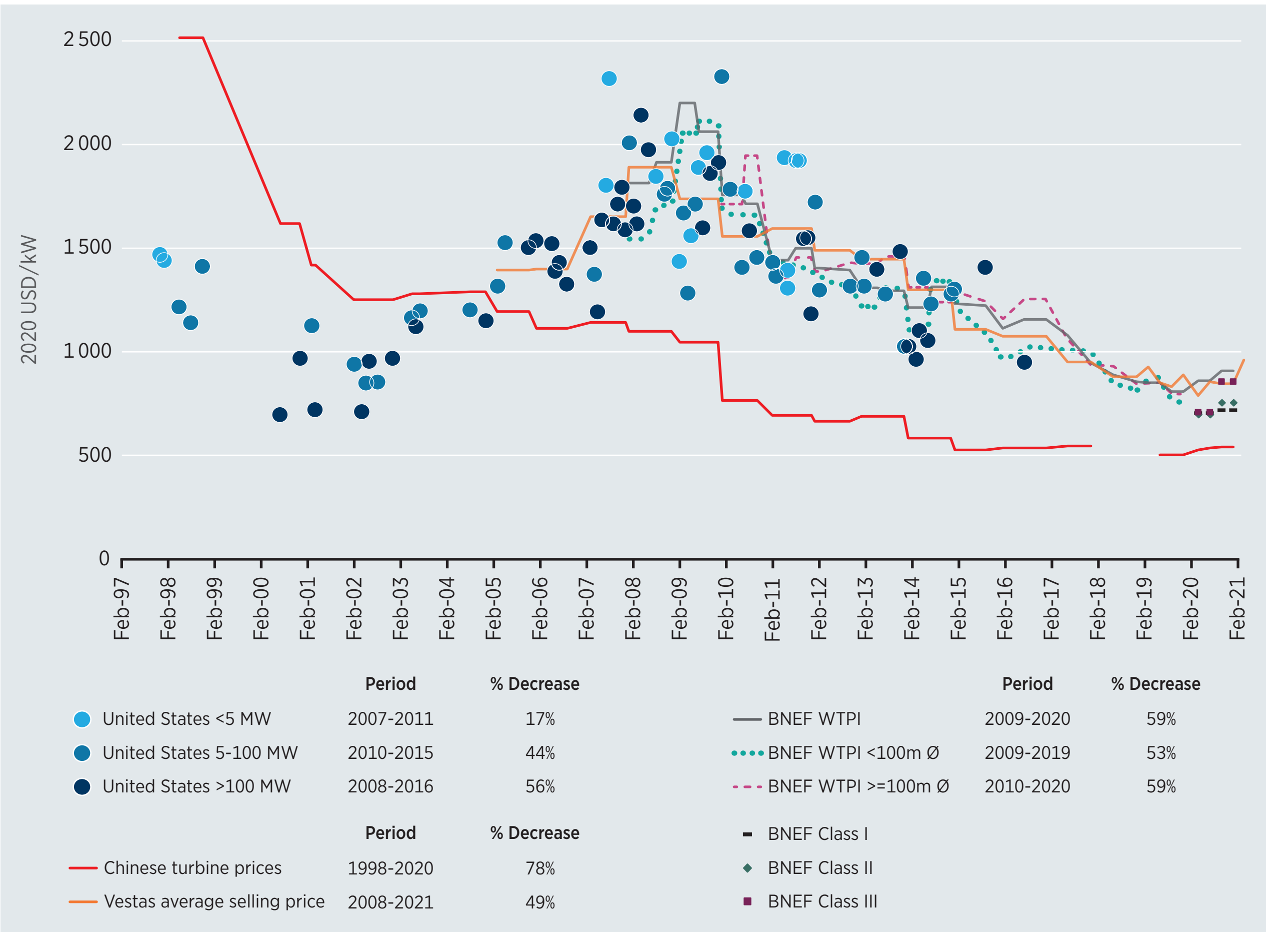

*Source: Based on CanWEA, 2016; GlobalData, 2021; IEA Wind, 2020; Danish Energy Agency, 2020; Wood Mackenzie, 2020a and IRENA Renewable Cost Database.*

4 *This increase in wind turbine prices in China is likely to be brief, as the policy shift to subsidy-free onshore wind has seen pressure on wind turbine manufacturers to agree to lower pricing for 2021 (Wood MacKenzie, 2021b).*

With greater competition among manufacturers, margins have come under increasing pressure to the benefit of consumers. For instance, Vestas saw its turbine sales margins drop below 10% in 2019 (BNEF, 2020a). This competition is being reinforced by the increased use of competitive procurement processes for renewable energy by a growing number of countries. Increased competition has also led to acquisitions in the turbine and balance-of-plant sectors and a trend of production moving to countries with lower manufacturing costs (Wood MacKenzie, 2020b). However, this increased competition does not make the sector immune from the impact of supply and demand imbalances. The significant growth in the market in 2020 and supply chain constraints due to COVID19, saw wind turbine pricing in late 2020 and early 2021 tick up, and turbine pricing is in the range of USD 910/kW to USD 960/kW for orders received in early Q1 2021 (BNEF, 2020b and Vestas, 2021).

The decline in turbine prices globally over the last decade occurred despite the increase in rotor diameters, hub-heights and nameplate capacities. In addition, price differences between turbines with differing rotor diameters narrowed significantly in 2019. This could be seen in the minimal percentage difference – 4% – between the prices of turbines with a rotor diameter above 100 m (USD 785/kW) and those with a rotor diameter of less than 100 m (USD 752/kW). However, in late 2020 the gap between Class I and Class III[5] wind turbines started to widen (BNEF, 2020b).

**Figure 2.3** Wind turbine price indices and price trends, 1997-2021




*Source: BNEF 2020b; Wiser, et al., 2020; Vestas Wind Systems, 2005-2021 and the IRENA Renewable Cost Database.*

*5 This refers to the International Electrical Commissions wind turbine classification. Broadly speaking, Class I wind turbines are designed for the best wind speed sites and typically have shorter rotors, and Class III turbines are designed for poorer wind conditions where larger rotor diameters and lower specific power (W/swept m²) are used to harvest the maximum energy.*

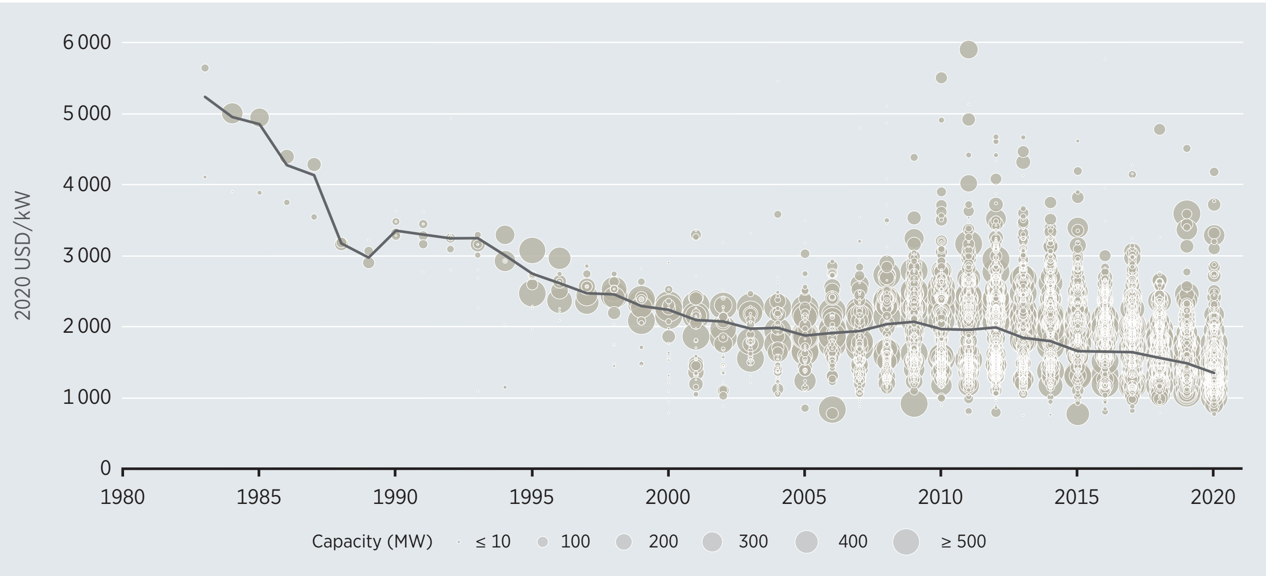
## ONSHORE WIND TOTAL INSTALLED COSTS

The global weighted-average total installed cost of onshore wind projects fell by 74% between 1983 and 2020, from USD 5 241/kW to USD 1 355/kW, based on data from the IRENA Renewable Cost Database (Figure 2.4). Global average total installed costs have fallen by up to 9% for every doubling in cumulative onshore wind capacity deployed globally. This has been driven by wind turbine price and balance-of-plant cost reductions. The global weighted-average total installed cost of onshore wind fell by 31% between 2010 and 2020, from USD 1 975/kW to USD 1 355/kW, with a 10% decline year-on-year in 2020.

*The global weighted-average total installed cost of onshore wind projects fell by 74% between 1983 and 2020, to USD 1 355/kW*

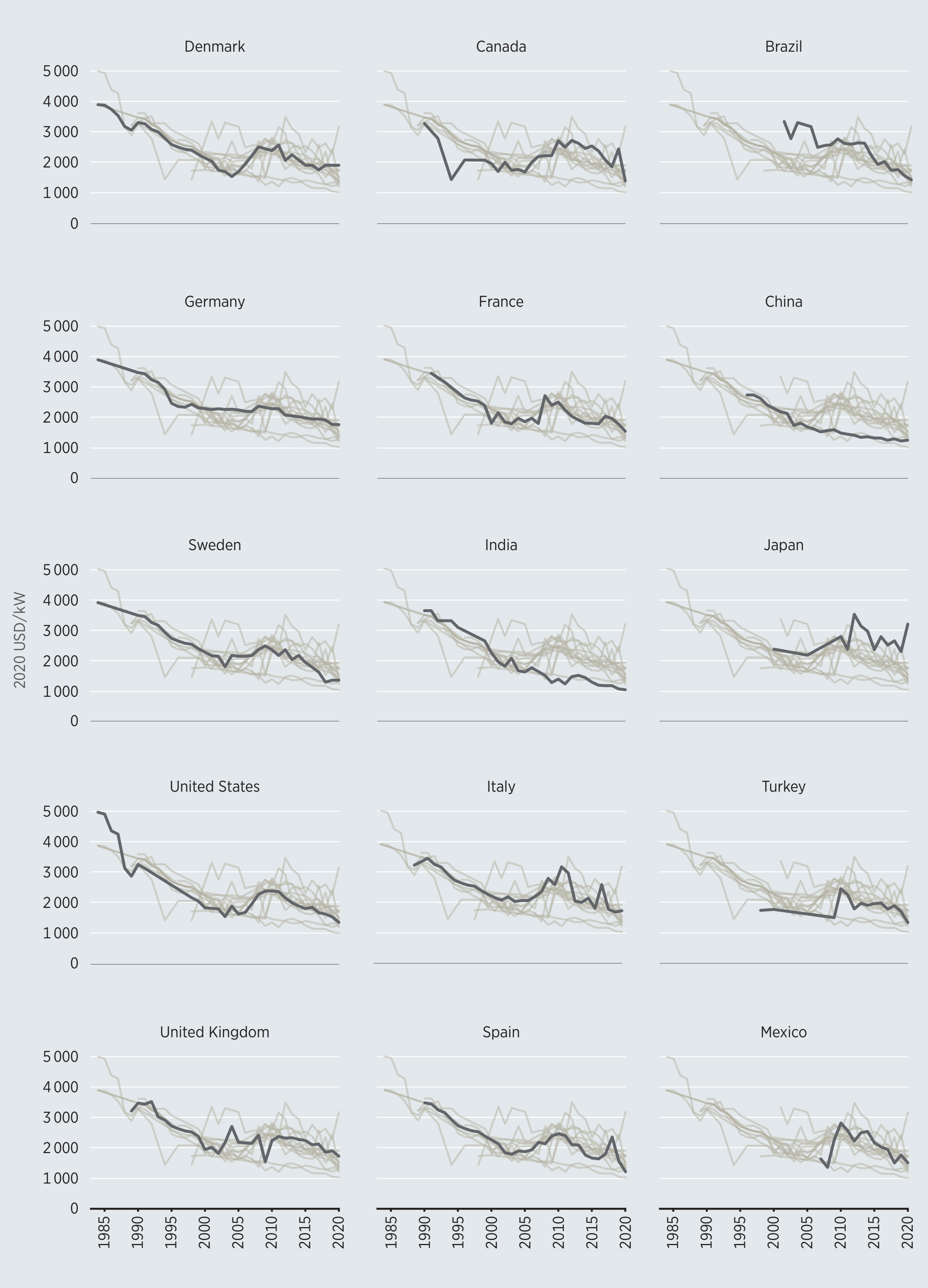
Figure 2.5 shows the trend in country-specific weighted-average total installed cost for 15 countries that are major wind markets and have significant time series data. Individual countries saw a range of cost reductions – from 72% in the United States to just 8% in Mexico – but these comparisons need to be treated with caution given the differing start dates for the first available data. Japan saw a 35% increase over the period shown, with the first cost data point in 2000. The more competitive, established markets show larger reductions in total installed costs over longer time periods than newer markets. The United States, followed by India, had the highest decrease in total installed costs with reductions of 72% and 71%, respectively. Spain and Sweden each saw a reduction of 65%, while Brazil and China saw reductions of 55% and 53%, respectively. There is, however, a wide range of individual project installed costs within a country and region. This is due to the different country and site-specific requirements, *e.g.,* logistics limitations for transportation, local content policies, land-use limitations, labour costs, etc.

**Figure 2.4** Total installed costs of onshore wind projects and global weighted-average, 1983-2020




*Source: IRENA Renewable Cost Database*

**Figure 2.5** Onshore wind weighted-average total installed costs in 15 countries, 1984–2020




*Source: IRENA Renewable Cost Database.*

Looking at the data at a regional level (Table 2.1) shows that the regions with the highest weighted-average total installed costs in 2020 were (in descending order): “Other Asia” (that is to say, excluding China and India), Central America and the Caribbean, and Africa, Oceania and South America (excluding Brazil). The regions with the next highest weighted-average total installed costs in 2020 were Europe, Brazil, Eurasia and North America.

China and India have more mature markets and lower cost structures than their neighbours. This can be seen in their lower average installed costs for onshore wind in 2020. India and China had the most competitive weighted-average total installed costs in 2020 – USD 1 038/kW and USD 1 264/kW, respectively – with installed costs falling by 27% in India and 16% in China since 2010.

**Table 2.1** Total Installed cost ranges and weighted averages for onshore wind projects by country/region, 2010 and 2020

| | 2010 | | | 2020 | | |
| --- | --- | --- | --- | --- | --- | --- |
| | 5th percentile | Weighted average | 95th percentile | 5th percentile | Weighted average | 95th percentile |
| | (2020 USD/kW) | | | | | |
| Africa | 1 390 | **1 609** | 3 035 | 1 275 | **1 873** | 3 225 |
| Central America and the Caribbean | 2 527 | **2 679** | 2 820 | 2 062 | **2 062** | 2 062 |
| Eurasia | 2 290 | **2 446** | 2 531 | 1 150 | **1 446** | 2 186 |
| Europe | 1 594 | **2 429** | 3 544 | 1 174 | **1 515** | 2 064 |
| North America | 1 893 | **2 474** | 3 213 | 1 066 | **1 403** | 2 059 |
| Oceania | 3 066 | **3 521** | 3 871 | 1 157 | **1 731** | 2 573 |
| Other Asia | 1 853 | **2 515** | 2 761 | 1 334 | **2 472** | 3 836 |
| Other South America | 2 426 | **2 644** | 2 763 | 1 085 | **1 607** | 2 560 |
| Brazil | 2 375 | **2 639** | 2 903 | 947 | **1 449** | 2 012 |
| China | 1 265 | **1 500** | 1 756 | 1 067 | **1 264** | 1 434 |
| India | 898 | **1 387** | 1 615 | 907 | **1 038** | 1 066 |

*Source: IRENA Renewable Cost Database.*
*Note: ‘Other Asia’ is Asia, excluding China and India. ‘Other South America’ is South America excluding Brazil.*

## CAPACITY FACTORS

The capacity factor represents the energy output from a wind farm on an annual basis as a percentage of the farm’s maximum output and is predominantly determined by two factors: 1) the quality of the wind resources where the wind farm is sited and 2) the turbine and balance-of-plant technology used. Figure 2.6 shows the correlation between capacity factor and estimated wind speed at the site of the wind farm.[6] The results should be considered indicative, but show the clear correlation between wind speed and capacity factor for the 290 projects commissioned in 2020 for which IRENA was able to identify the exact wind farm site (see Appendix I).

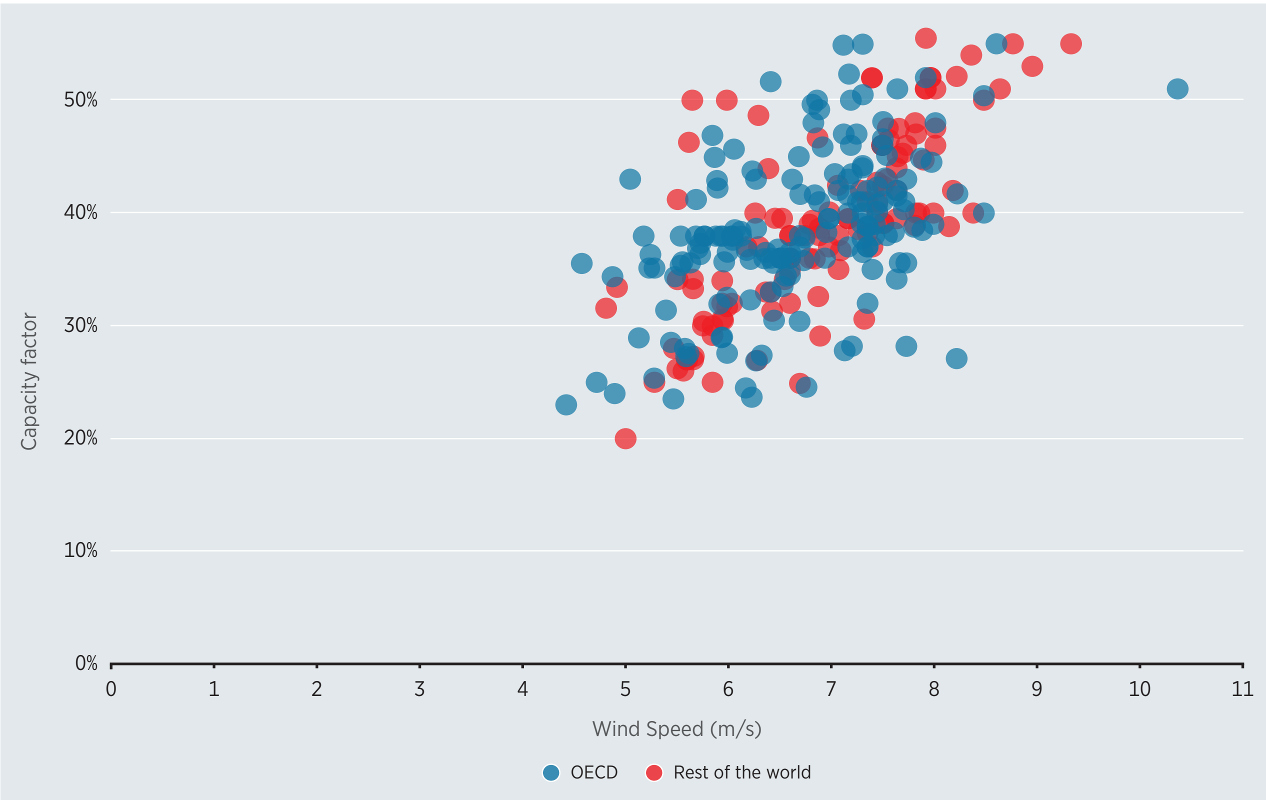
6 *Significant uncertainty surrounds the estimate of the individual wind farm wind speed estimate. Typically, IRENA has used a single point estimate to determine the wind farm speed using the IRENA Wind Atlas. However, when micro-siting the wind turbine to optimise wind speeds and reduce wake losses, a single point estimate may be misleading. This is especially true for larger wind farms that can be spread over a large geographic area. However, without the site measurements, IRENA was constrained to use the point estimate. Other complications involve interpolation of wind data at different hub-heights and the smoothness of the wind resource (given that more turbulent or gusty winds will result in lower capacity factors than the same annual average wind speed with smoother wind patterns).*

The trend towards more advanced and more efficient turbine technologies with larger rotor diameters and hub-heights has seen energy outputs and capacity factors rise in most markets over the last ten years. The global weighted-average capacity factor for onshore wind increased by 81% between 1983 and 2020, from around 20% in the former year to 36% in the latter. This upward trend has also been observed during the past decade (2010-2020). During this period, there was an almost one-third increase in the capacity factor, from just over 27% in 2010 to 36% in 2020. Between 2019 and 2020, the capacity factor remained at 36%. China's higher share of global deployment in 2020, with its – in general – poorer wind resources, had a significant impact on the global weighted-average capacity factor.

*The global weighted-average capacity factor for onshore wind increased by 81% between 1983 and 2020*

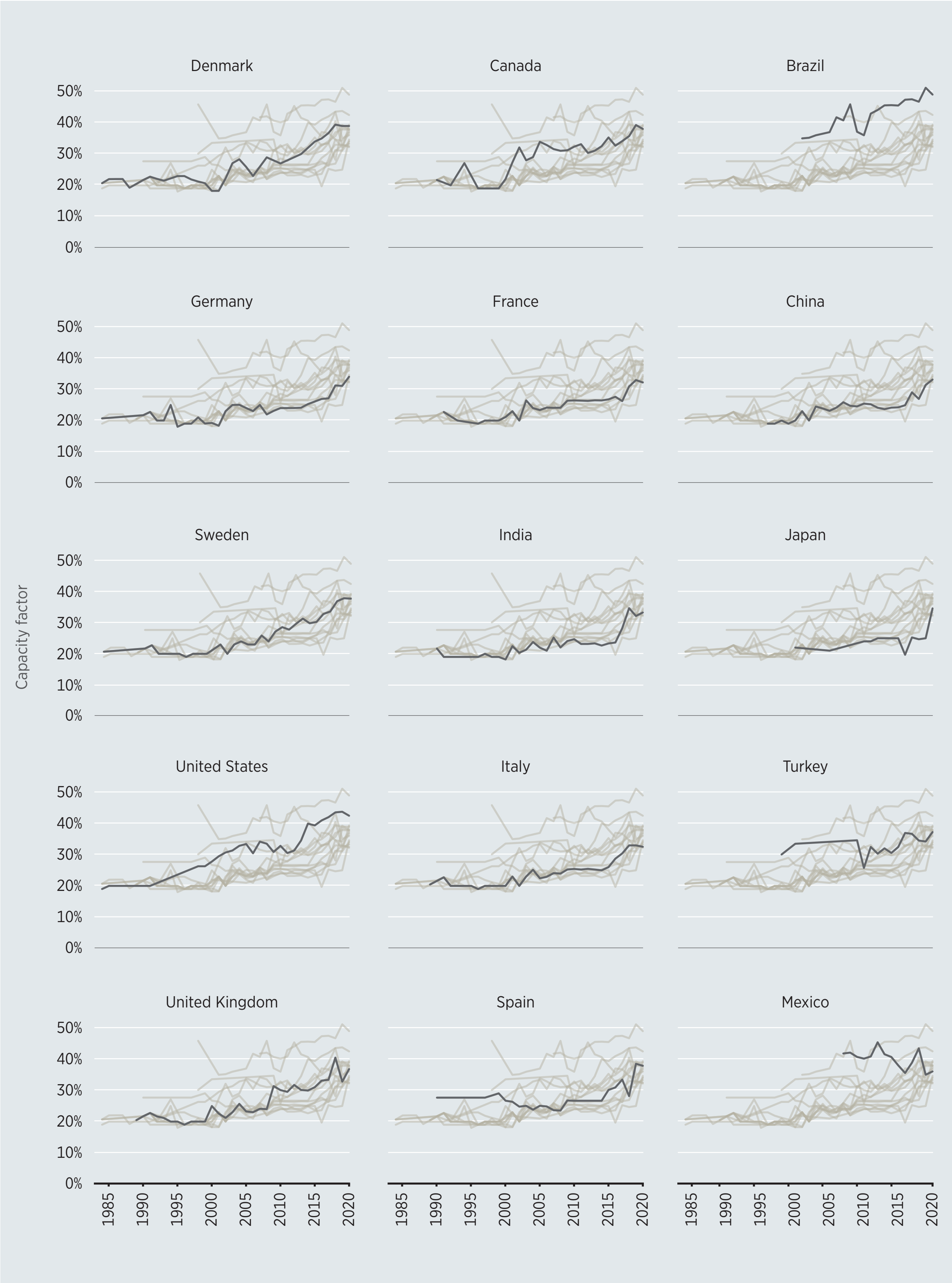
Resource quality has a significant impact on capacity factors, even as technology improvements have raised outputs across the board. There is, therefore, still wide variation across markets predominantly due to differing wind resource qualities, but also, to a lesser extent, the different technologies used and site configurations. Not all capacity factor improvements are the result of turbine technology improvements, as owing to advancements in remote sensing and computing, there have been improvements in wind resource characterisation and the siting of turbines in order to minimise wake losses. This has enabled the selection of better wind sites and better wind farm layouts for optimal energy output.

**Figure 2.6** Historical onshore wind average capacity factors and wind speed for projects commissioned in 2020




*Source: IRENA Renewable Cost Database.*

**Figure 2.7** Historical onshore wind weighted-average capacity factors in 15 countries, 1984–2020




*Source: IRENA Renewable Cost Database.*

Figure 2.7 depicts the historical evolution of onshore wind capacity factors for commissioned projects in each year across the 15 markets where IRENA has the longest time series data. Average capacity factors increased by just over half for the 15 countries examined in Figure 2.6. Granted, there are varying start dates for commercially deployed projects, but nonetheless, this shows the scale of capacity factor improvements. Indeed, compared to the earliest commissioned project in 1996 in China, capacity factors in 2020 increased 74%, while capacity factors in Denmark, Sweden, the United Kingdom and the United States have increased by more than 80% between their earliest deployment and 2020. Brazil, like the United States, has excellent onshore wind resources and in 2020, newly commissioned projects had a weighted-average capacity factor of 49%.

Table 2.2 shows the more recent change in capacity factors for projects commissioned in the same 15 countries for the 2010-2020 period. Except for Mexico, all the countries experienced improvements in the weighted-average capacity factor, with an increase of between 18% in Canada and 45% in Turkey.

## OPERATION AND MAINTENANCE COSTS

Operation and maintenance costs for onshore wind often make up a significant part (up to 30%) of the LCOE for this technology (IRENA, 2018). Technology improvements, greater competition among service providers, and increased operator and service provider experience are, however, driving down O&M prices. This trend is being supported by increased efforts by turbine OEMs to secure service contracts given these contracts' potentially have higher profit margins compared to those of turbine supply (BNEF, 2020; Wood MacKenzie, 2019).

**Table 2.2** Country-specific average capacity factors for new onshore wind, 2010 and 2020

| | 2010 | 2020 | Percentage change 2010-2020 |
|---|---|---|---|
| | % | | |
| Brazil | 36 | 49 | 36% |
| Canada | 32 | 38 | 18% |
| China | 25 | 33 | 30% |
| Denmark | 27 | 39 | 44% |
| France | 26 | 32 | 22% |
| Germany | 24 | 34 | 42% |
| India | 25 | 33 | 35% |
| Italy | 25 | 33 | 28% |
| Japan | 24 | 35 | 44% |
| Mexico | 40 | 36 | -10% |
| Spain | 27 | 38 | 42% |
| Sweden | 29 | 38 | 32% |
| Turkey | 26 | 37 | 45% |
| United Kingdom | 30 | 37 | 22% |
| United States | 33 | 43 | 29% |

*Source: IRENA Renewable Cost Database.*

Nonetheless, the share of the O&M market covered by turbine OEMs continues to shrink, with asset owners increasingly internalising major parts of O&M services or using independent service providers to reduce costs. This share fell from 70% in 2016 to 64% in 2017, and it is expected to fall a further ten percentage points by 2027, to 54% (Make Consulting, 2017).

Figure 2.8 shows O&M costs in selected countries, along with BNEF O&M price indexes. The latter are represented as either initial full-service contracts or full-service contracts for already established wind farms, which are more expensive because they factor in the ageing of turbines. The data show an observable downward trend in O&M costs that reflects the maturity and competitiveness of the market. Initial full-service contracts fell 66% between 2008 and 2019 while full-service renewal contracts declined by 50% between 2011 and 2019. At the country level, between 2016 and 2018, O&M costs for onshore wind have ranged from USD 33/kW per year (in Denmark) to USD 56/kW per year (in Germany) – which is known for having higher than average onshore wind O&M costs. The difference between the contract prices and observed country O&M costs is explained by the additional, predominantly operational expenses not covered by service contracts (*e.g.,* insurance, land lease payments, local taxes, etc.).

**Figure 2.8** Full-service (initial and renewal) O&M pricing indexes and weighted-average O&M costs in Denmark, Germany, Ireland, Japan, Norway, Sweden and the United States, 2008-2020


*Source: BNEF (2019b); IEA Wind (2021).*

## LEVELISED COST OF ELECTRICITY

The LCOE of an onshore wind farm is determined by the total installed costs, lifetime capacity factor, O&M costs, the economic lifetime of the project, and the cost of capital. While all of these factors are important in determining the LCOE of a project, some components have a larger impact. For instance, the cost of the turbine (including the towers) makes up the most significant component of total installed costs in an onshore wind power project. With no fuel costs, the capacity factor and cost of capital also have a significant impact on LCOE.

The O&M costs, comprising fixed and variable components, made up from 10% to 30% of the LCOE in 2020 for the majority of projects. Reductions in O&M costs have been increasingly important in driving down LCOEs, as turbine price reductions are contributing less in absolute terms to cost reductions given their low levels today.

Figure 2.9 presents the evolution of the LCOE (global weighted average and project level) of onshore wind between 1983 and 2019. Over that period, the global weighted-average LCOE declined by 87%, from USD 0.311/kWh to USD 0.041/kWh. In 2010, the LCOE was USD 0.089/kWh, meaning there was a 54% decline over the decade to 2020. Consequently, onshore wind now increasingly competes with hydropower as the most competitive renewable technology, without financial support.

Factors behind the decline the in the global weighted-average LCOE include:

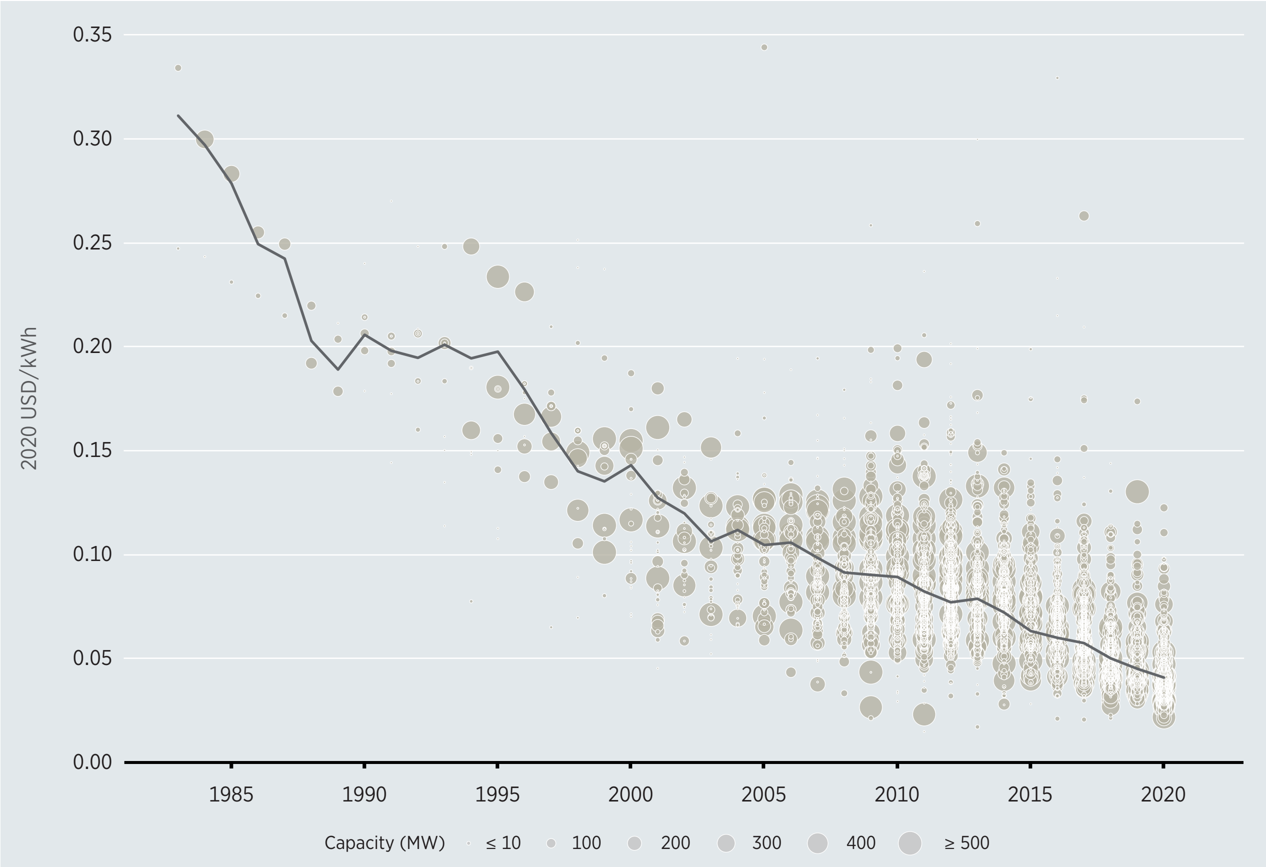
- **Turbine technology improvements:** With the increase in turbine sizes and swept areas, the process of optimising the rotor diameter and turbine ratings, *i.e.* the specific power, has led to increased energy yield and thus project viability for the asset owner, depending on site characteristics. In addition, the practice of optimising the site configuration to better exploit wind resources and reduce output losses due to turbulence has become more common with improved wind resource characterisation and project design software. Consequently, this has increased energy yields, reduced O&M costs per unit of capacity, and driven down LCOEs (Lantz *et al.*, 2020).

- **Economies of scale:** Economies of scale impact the costs of manufacturing, installation (with the reduction in the number of turbines required for a project due to the higher turbine ratings) and O&M costs.

- **O&M costs:** Digital technologies have allowed for improved data analytics and autonomous inspections. This has been joined by improvements in the reliability and durability of new turbines, while larger turbines have reduced the number of turbines for a given capacity. Improved O&M practices have also contributed to lower O&M costs. In addition, more players are entering the O&M servicing sector for onshore wind, which is increasing competition and driving down costs (BNEF, 2019c, 2020).

- **Competitive procurement:** The shift from feed-in-tariff support schemes to competitive auctions is leading to further cost reductions as it drives competitiveness across the supply chain, from development to O&M, both at a local and global scale. For turbine manufacturers, the supply chain has also moved to support regional hubs and countries to minimise labour and delivery costs, further improving competitiveness.

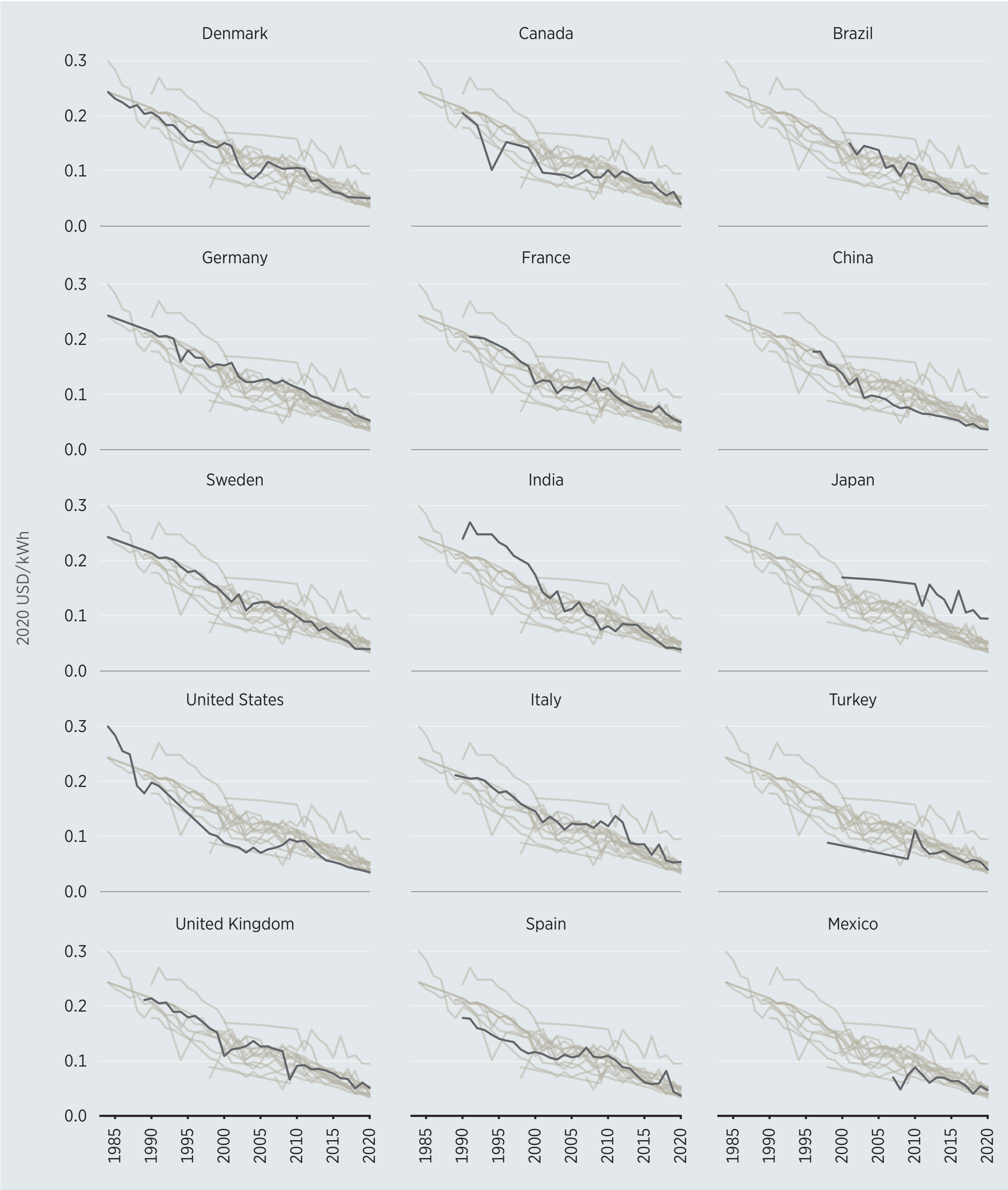
**Figure 2.9** LCOE of onshore wind projects and global weighted average, 1983–2020




*Source: IRENA Renewable Cost Database.*

The growing maturity of the market (cumulative deployment grew by 682 GW between 2000 and 2020) should also not be overlooked. Increased operational experience and favourable government regulations and policies have reduced project development and operation risks for onshore wind, especially in established markets. Development, installation and operational risks are now better understood, with adequate mitigation measures in place, all driving down project risk.

**Figure 2.10** The weighted-average LCOE of commissioned onshore wind projects in 15 countries, 1984–2020




*Source: IRENA Renewable Cost Database.*

Figure 2.10 presents the historical evolution of the LCOE of onshore wind in 15 countries where IRENA has the longest time series data. The data should be interpreted with care, and cross-country comparisons are problematic, because of the variation in base years for each country in the data available to IRENA. Having noted this, among the 15 countries analysed the biggest LCOE reduction – 88% – was in the United States, which had the largest reduction – 72% – in average total installed costs and saw an 80% improvement in average capacity factor. Sweden and India had the second and third largest weighted-average LCOE reductions, at 84% and 83%, respectively, followed by China, which had a weighted-average LCOE reduction of 79%. In 2020, with the exception of Japan, all the 15 countries analysed in Figure 2.10 had weighted-average LCOEs below USD 0.055/kWh – the lower range for fossil fuel-fired power generation.

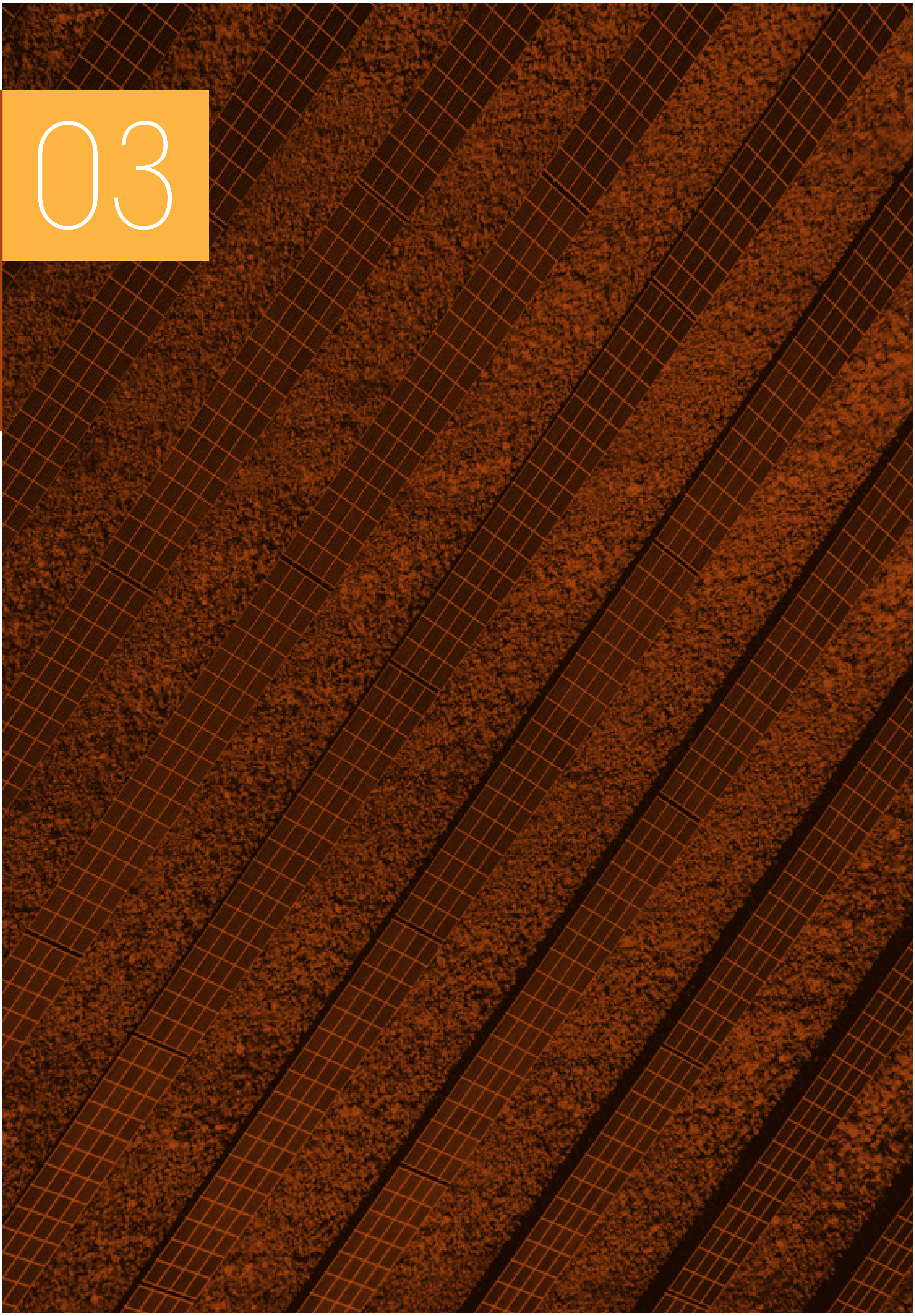
Table 2.3 shows the country/region weighted-average LCOE and 5th and 95th percentile ranges by region in 2010 and 2020. In 2020, the highest weighted-average LCOE for commissioned projects by region was USD 0.081/kWh in the "Other Asia" category (*e.g.,* excluding China and India), while projects commissioned in China and North America saw the lowest weighted-average LCOE, at USD 0.037/kWh. The highest LCOE reductions between 2010 and 2020 were in North America, at 59% (USD 0.092/kWh to USD 0.037/kWh). Europe had the second highest LCOE reduction for the same period at 58%, and Brazil, Eurasia and "Other South America" (excluding Brazil) had a reduction of 57%. Wind power projects are increasingly achieving LCOEs of less than USD 0.040/kWh, and in some cases, as low as USD 0.030/kWh. The most competitive weighted-average LCOEs below USD 0.050/kWh were observed across different regions: in Asia (India and China), Europe (Finland and Sweden), Africa (Egypt), North America (the United States), and South America (Argentina and Brazil). Considering LCOE ranges regionally, in 2020, the 5th and 95th percentile range for the global weighted-average LCOE was between USD 0.026/kWh in China and USD 0.113/kWh in "Other Asia".

**Table 2.3** Regional weighted-average LCOE and ranges for onshore wind in 2010 and 2020

| | 2010 | | | 2020 | | |
|---|---|---|---|---|---|---|
| | 5th percentile | Weighted average | 95th percentile | 5th percentile | Weighted average | 95th percentile |
| | (2020 USD/kW) | | | | | |
| Africa | 0.073 | **0.091** | 0.100 | 0.041 | **0.055** | 0.083 |
| Central America and the Caribbean | 0.095 | **0.095** | 0.095 | 0.059 | **0.059** | 0.059 |
| Eurasia | 0.112 | **0.112** | 0.112 | 0.031 | **0.047** | 0.070 |
| Europe | 0.076 | **0.113** | 0.164 | 0.035 | **0.045** | 0.065 |
| North America | 0.060 | **0.092** | 0.124 | 0.028 | **0.037** | 0.054 |
| Oceania | 0.107 | **0.121** | 0.132 | 0.037 | **0.052** | 0.068 |
| Other Asia | 0.103 | **0.137** | 0.147 | 0.058 | **0.081** | 0.113 |
| Other South America | 0.087 | **0.101** | 0.131 | 0.032 | **0.044** | 0.063 |
| Brazil | 0.110 | **0.112** | 0.123 | 0.030 | **0.041** | 0.062 |
| China | 0.058 | **0.071** | 0.089 | 0.026 | **0.037** | 0.047 |
| India | 0.053 | **0.082** | 0.101 | 0.029 | **0.040** | 0.051 |

*Source: IRENA Renewable Cost Database.*

# 03

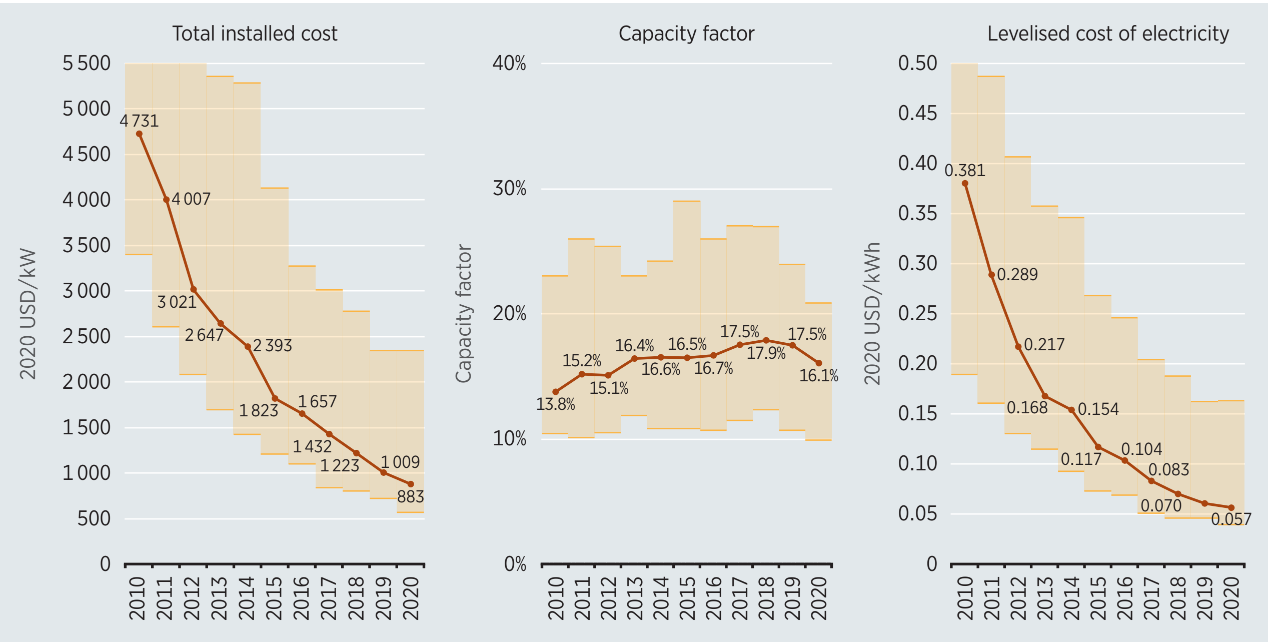


# SOLAR PHOTOVOLTAICS

## HIGHLIGHTS

- The global weighted-average levelised cost of electricity (LCOE) of utility-scale photovoltaic (PV) plants declined by 85% between 2010 and 2020, from USD 0.381/kilowatt hour (kWh) to USD 0.057/kWh in 2020. The year-on-year reduction that year was 7%.
- At an individual country level, the weighted average LCOE of utility-scale solar PV declined by between 77% and 88% between 2010 and 2020.
- The cost of crystalline solar PV modules sold in Europe declined by around 93% between December 2009 and December 2020.
- The global capacity weighted-average total installed cost of projects commissioned in 2020 was USD 883/kilowatt (kW), 81% lower than in 2010 and 13% lower than in 2019.
- Solar PV capacity grew 16-fold between 2010 and 2020, with over 707 GW installed at the end of 2020.
- The total installed costs in the residential rooftop PV market are higher than in the utility-scale market. They decreased by between 46% and 85% between 2010 and 2020, depending on the market.
- Total installed system costs in the commercial rooftop markets where data is available decreased between 69% and 88% between 2010 and 2020.
- On average, in 2020, balance of system (BoS) costs (excluding inverters) made up about 65% of total installed costs.
- The global weighted-average capacity factor for new, utility-scale solar PV increased from 13.8% in 2010 to 16.1% in 2020. This change results from the combined effect of evolving inverter load ratios, a shift in average market irradiance and the expanded use of trackers, driven largely by increased adoption of bifacial technologies, that unlock its use in more latitudes.

**Figure 3.1** Global weighted-average total installed costs, capacity factors and LCOE for PV, 2010–2020




*Source: IRENA Renewable Cost Database*

## RECENT MARKET TRENDS

By the end of 2020, over 707 GW of solar PV systems had been installed, worldwide. This represented more than 16-fold growth for the technology since 2010. About 127 GW of newly installed systems was commissioned during 2020 alone. These new capacity additions were the highest among all renewable energy technologies that year.

Asia has led new solar PV installations since 2013. Following that trend, growth in 2020 was driven by continued new capacity additions in that region. Asia contributed about 60% of all new installations that year. Developments there were driven by China, where around two-thirds of all new Asian PV installations occurred. Meanwhile, after emerging as an important new market in 2019, Viet Nam's new installations more than doubled between 2019 and 2020. The country installed more than 11.6 GW of PV during that year to become the second largest market in Asia. Japan, India and the Republic of Korea together contributed another 13.7 GW of new PV capacity during 2020.

Historical markets outside Asia also continued to gain scale. Compared to 2019, new capacity in the United States doubled. During 2020, the United States, Australia and Germany together installed 24 GW, while Brazil and the Netherlands exceeded 3 GW each in new installations, creating combined growth of about a third of the total in 2019 (IRENA, 2021).

## TOTAL INSTALLED COSTS

### Solar PV module cost trends

The downward trend in solar PV module costs has been an important driver of improved competitiveness historically – and this trend continued during 2020. Between December 2009 and December 2020, crystalline silicon module prices declined between 89% and 95% for modules sold in Europe, depending on the type. The weighted average cost reduction was in the order of 93% during that period. Between 2019 and 2020, the yearly average module price declined between 5% and 15% for crystalline modules.

*Between December 2009 and December 2020, crystalline silicon module prices declined between 89% and 95%*

During December 2020, mainstream modules sold for USD 0.27/watt (W). A wide range of costs exists, however, depending on the module technology considered. Costs varied from as low as USD 0.19/W for the lower cost modules to as as a high as between USD 0.38 and USD 0.40/W for high efficiency, all black and bifacial modules. This cost range is between 9% and 11% lower than it was during December 2019.

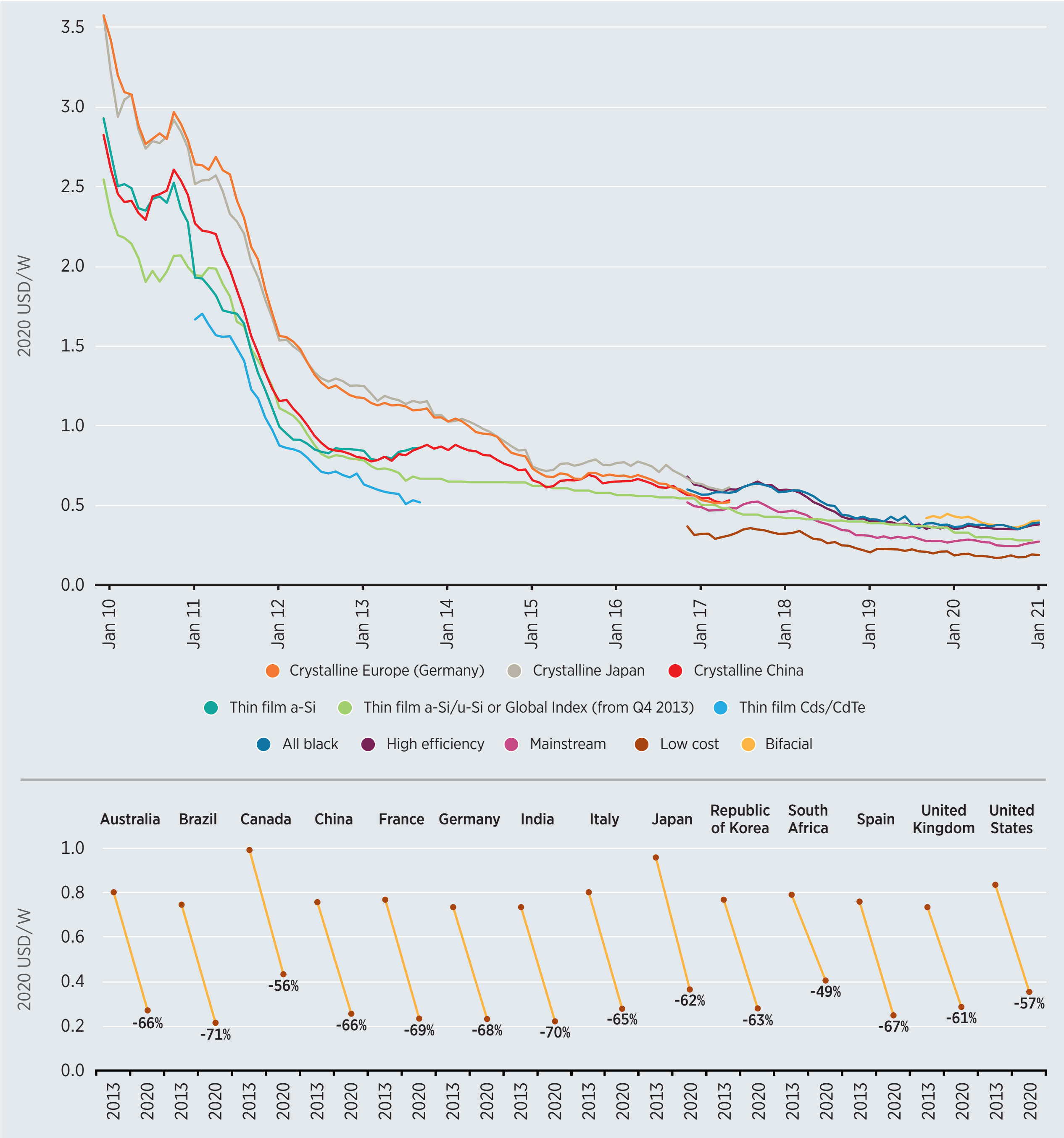
Thin film offerings sold for USD 0.28/W during December 2020, after seeing a cost decline of 22% between December 2019 and December 2020. Among crystalline technologies, the cost of bifacial modules declined 10% during the same period, as market adoption and the competitiveness of the technology increased. Bifacial crystalline modules sold 21% higher than high efficiency, monofacial modules during December 2019. This cost premium fell to 6% during December 2020. It points to bifacial module costs being more driven by the cost of cell architectures types used to build them, rather than by the bifacial design in itself.

Driven by this narrowing cost gap and its potential for increased yield per watt when compared to monofacial technologies, bifacial modules continue to grow their market share. During 2019, the market share for these was about 8%. This share reportedly grew to between 17% and 28% during 2020 (ITRPV, 2021).

Between 2013 and 2020, market-level module costs declined by between 49% (South Africa) and 71% (Brazil) for the markets for which historical data is available. Data for 2020 shows that a wide range of module costs still exists among the evaluated markets.

Compared to 2019, however, the cost range has narrowed, in USD/W terms (from USD 0.32/W to USD 0.22/W). During 2020, the highest module cost was twice the lowest in the markets assessed (compared to 2.4 times higher in 2019). At the same time, module cost reductions of between 2% and 38% occurred in all assessed markets between 2019 and 2020. This points to the increasing cost maturity of a growing number of markets (Figure 3.2).

**Figure 3.2** Average monthly solar PV module prices by technology and manufacturing country sold in Europe, 2010 to 2020 (top) and average yearly module prices by market in 2013 and 2020 (bottom)




*Source: GlobalData (2021); pvXchange (2021); Photon Consulting (2017); IRENA Renewable Cost Database*

Recent disruption in the global module market balance dynamics and higher material costs are likely responsible for an uptick in module costs during early 2021. Costs for the first quarter of that year were between 1% and 9% higher, depending on the module type, than the 2020 module averages reported in Figure 3.2. This imbalance is related to increasing polysilicon prices and other supply and demand challenges in the upstream market. It is not yet known how the market will be affected for the full year. Capacity expansions already underway at the leading polysilicon manufacturers are likely to bring polysilicon pricing back to previous low levels. In the longer term, in addition, the continued improvement of efficiency, manufacturing optimisation and design innovation are expected to more than offset this temporary cost increase.

Various factors are expected to continue to contribute to increasing solar PV technology's competitiveness. For example, further adoption of bifacial technologies built from increasingly efficient cells is expected to continue. The average module efficiency of crystalline modules increased from 14.7% in 2010 to 20% in 2020. That rise was driven by a market shift from multycristalline more efficient monocrystalline products and by passivated emitter and rear cell (PERC) architectures having become the state-of-the-art technology in modules. The efficiency of PERC modules is expected to grow towards 22% in the next few years, as it approaches its limits. In terms of cell architecture beyond PERC, likely candidates to drive efficiencies higher take two main approaches: first, by focusing on reducing losses at contacts (*e.g.* heterojunction [HJT] and tunnel oxide passivated contact [TOPCon] technology), or second, by focusing on moving metallisation to the rear of the cell to reduce front-side shading (*e.g.* interdigitated back contact [IBC] or cells).

Yet, at the module design level – independent from the cell – recent developments in technology have contributed to increasing module power outputs. Half-cut cells, multi-busbars and high-density cell packing pathways, such as shingling and others, are clear examples of this. They are also expected to continue to be increasingly utilised in the future.

Until recently, the prevalent module design has been based on square, or pseudo-square, crystalline silicon cells. These have an approximate side length of 156 millimetres (mm)-159 mm and are based on wafer formats known as M2 and G1. Cells are typically connected in series using metallic ribbon, soldered to the front busbars of one cell and the rear busbars/soldering pads of the adjacent cell. As cells have evolved, busbars have increased in number from 2 per cell to 4-8 per cell in mainstream production. With the aim of maximising power output, this typical module design is changing rapidly. Alternative designs with variants such as half-cell modules, shingled cell modules and multi-busbar cells/modules (with as many as 12 thinner busbars) continue to mature. Newer modules are increasingly based on larger wafer formats and current wafer sizes are likely to rapidly give way to larger formats of 182-210 mm side length.

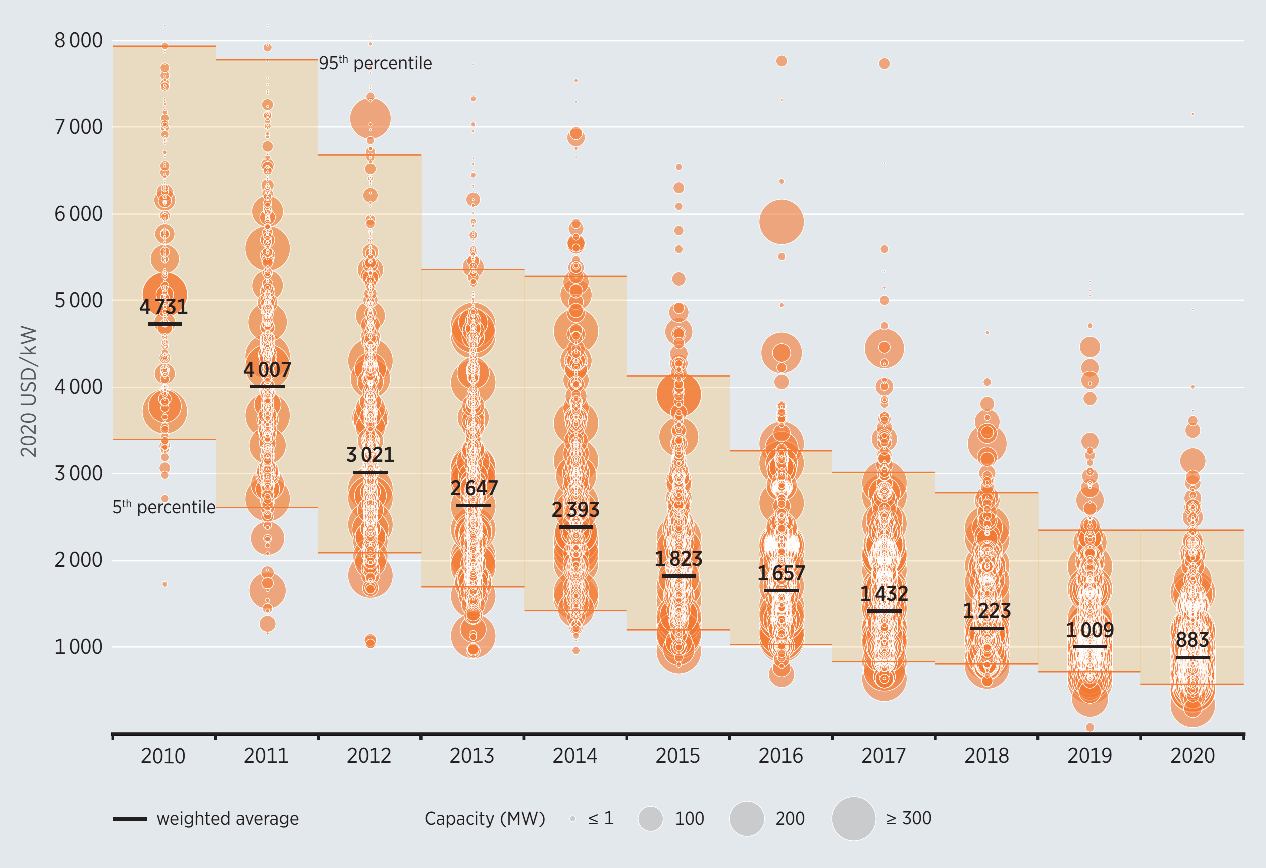
These technological changes have meant that the power output of modules has seen important growth in recent years. For example, in 2017, typical module power output for top modules was 350 W, while currently, 500 W is the new norm, though modules with output beyond 600 W are also already commercial. Given the diversification of module designs, however, a pure comparison of module power rating as labelled may be misleading, with the efficiency of the modules remaining the most important performance metric. (TaiyangNews 2020, 2021; ITRPV 2021; Lin, 2019).

In addition, increased adoption of bifacial technology is an important driver for solar PV competitiveness, given its potential for increased yield per watt, compared to monofacial technologies. Bifacial cells allow light to enter from the rear of the cell, as well as the front. The rear-side of bifacial cells features metallisation in a grid, similar to the traditional front-side cell metallisation. Bifacial cells are typically employed in a bifacial module, in which the opaque rear back sheet is usually replaced by glass, to allow light to enter the module from the rear. Light entering the rear of a bifacial module can contribute to power generation in much the same way as light entering the front, although the bifaciality factor for most modules (the ratio of rear-side efficiency to front-side efficiency) has been reported in the range of 65-95% (TaiyangNews, 2018). Bifaciality is a characteristic that depends on the structure of cells and modules. The 'bifacial gain', or output gain from a bifacial module compared to a monofacial module, however, does not depend only on the bifaciality factor. It also depends on the additional, external conditions of the system installation type and its location, with these factors affecting the angular distribution of light reaching the rear side. Among the most important factors are: module orientation and tilt angle; ground albedo (the ratio of light reflected); module elevation relative to the ground (also known as 'level above ground'); module height; the diffuse irradiance fraction and self-shading. Bifacial modules are being increasingly applied in utility-scale plants that use single-axis tracking. Their energy yield advantage is broadening the latitue range of competitive tracking PV plants.

### Total installed costs

The global capacity weighted-average total installed cost of utility-scale projects commissioned in 2020 was USD 883/kW (13% lower than in 2019 and 81% lower than in 2010). During 2020, the 5$^{th}$ and 95$^{th}$ percentile range for all projects fell within a range of USD 572/kW to USD 2 346/kW. The 95$^{th}$ percentile value was still at par with 2019 data, while the 5$^{th}$ percentile value declined by a fifth between 2019 and 2020. The long-term reduction trend in this cost range points towards continued cost structure improvements in an increasing number of markets. Compared to 2010, the 5$^{th}$ and 95$^{th}$ percentile values were 83% and 70% lower, respectively (Figure 3.3).

**Figure 3.3** Total installed PV system cost and weighted averages for utility-scale systems, 2010-2020




*Source: IRENA Renewable Cost Database*

Solar PV total installed cost reductions are related to various factors. The key drivers of lower module costs are the optimisation of manufacturing processes, reduced labour costs and enhanced module efficiency. Furthermore, as project developers gain more experience and supply chain structures continue to develop in more and more markets, declining BoS[1] costs have followed. This has led to an increased number of markets where PV systems are achieving competitive cost structures and falling global weighted-average total installed costs. In 2020, significant total installed cost reductions occurred across all the major historical markets, such as China, India, Japan, the Republic of Korea, the United States and Germany.

Projects with very competitive costs in India led to weighted-average total installed costs of USD 596/kW in 2020, a value 8% lower than in China. This differential was 22% during 2019 and fell as costs in China declined 19% between 2019 and 2020, compared to 5% in India. During 2020, total installed costs in Germany declined 23% compared to 2019, while in the Republic of Korea, they fell by a quarter, with the total installed cost decline between 2010 and 2020 reaching 90%.

*1 See Annex I for a description of all the BoS categories that are tracked by IRENA.*

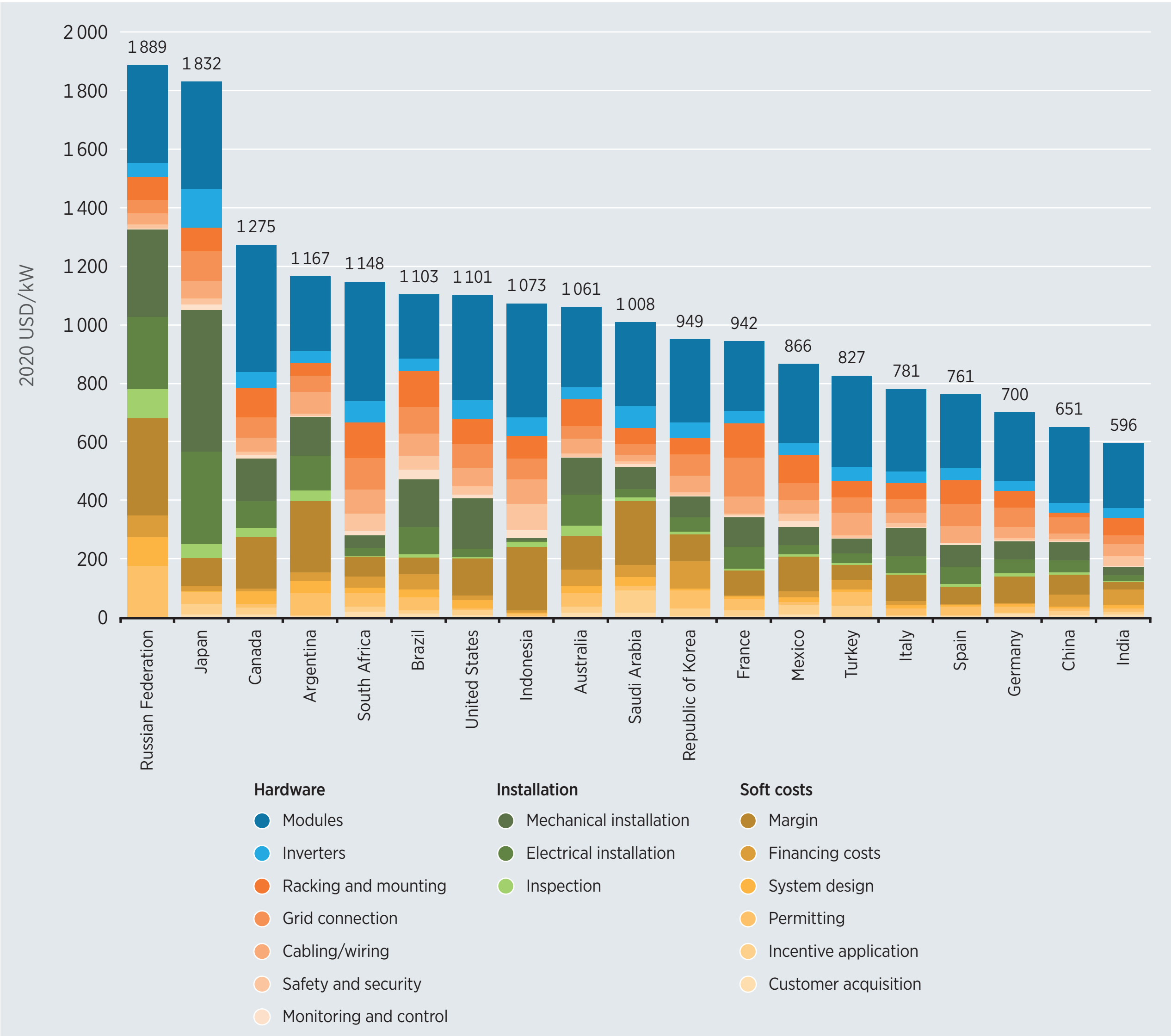
In Spain, some very competitive subsidy-free projects came online during 2020. The weighted-average total installed cost in Spain that year was USD 761/kW, a value 9% higher than in Germany, though below the global weighted average. In addition to this, competitive cost structures continue to prevail in the more recently established markets, such as Viet Nam and the Netherlands. Indeed, during 2020, Viet Nam became the third largest PV market in the world. On a par now with the Republic of Korea, the weighted-average total installed cost in Viet Nam reached USD 949/kW that year. This represented an 11% fall on 2019 and a decline of 58% on 2016, when the first data for the market became available (Figure 3.4).

**Figure 3.4** Utility-scale solar PV total installed cost trends in selected countries, 2010-2020


*Source: IRENA Renewable Cost Database*

While solar PV has become a mature technology, regional cost variations do persist (Figure 3.5). These differences remain not only for the module and inverter cost components, but also for the BoS. At a global level, cost reductions for modules and inverters accounted for 61% of the global weighted-average total installed cost decline between 2010 and 2020. This means that BoS[2] costs are therefore also an important contributor to declining global weighted-average total installed costs. Between 2010 and 2020, 13% of the global reduction came from lower installation costs, 7% from racking, 3% from other BoS hardware (*e.g.,* cables, junction boxes, etc.) and 16% from a range of smaller categories. The reasons for BoS cost reductions relate to competitive pressures and increased installer experience, which has led to improved installation processes and soft development costs. BoS costs that decline proportionally with the area of the plant have also declined as module efficiencies have increased.

**Figure 3.5** Detailed breakdown of utility-scale solar PV total installed costs by country, 2020




*Source: IRENA Renewable Cost Database*

*2 BoS costs in this chapter do not include inverter costs, which are treated separately.*

In 2020, the country average for the total installed costs of utility scale solar PV for the countries reported in Figure 3.5 ranged from a low of USD 596/kW in India to a high of USD 1 889/kW in the Russian Federation. The highest cost average was about three-and-a-half times more than the lowest during 2019, whereas in 2020 this ratio declined to about 3.2. This points to the convergence of installed costs in major markets, in recent years.

On average, in 2020, BoS costs (excluding inverters) made up about 65% of total system costs in the countries in Figure 3.5. During 2016, they made up about half of the total system cost. This increased share highlights the increasing importance of BoS costs, as module and inverter costs continue to come down. In 2020, total BoS costs ranged from a low of 55% in China to a high of 80% in the Russian Federation. Overall, soft cost categories for the countries evaluated made up around 35% of total BoS costs and, on average, 23% of the total installed costs. In 2016, these values were a third and 17%, respectively.

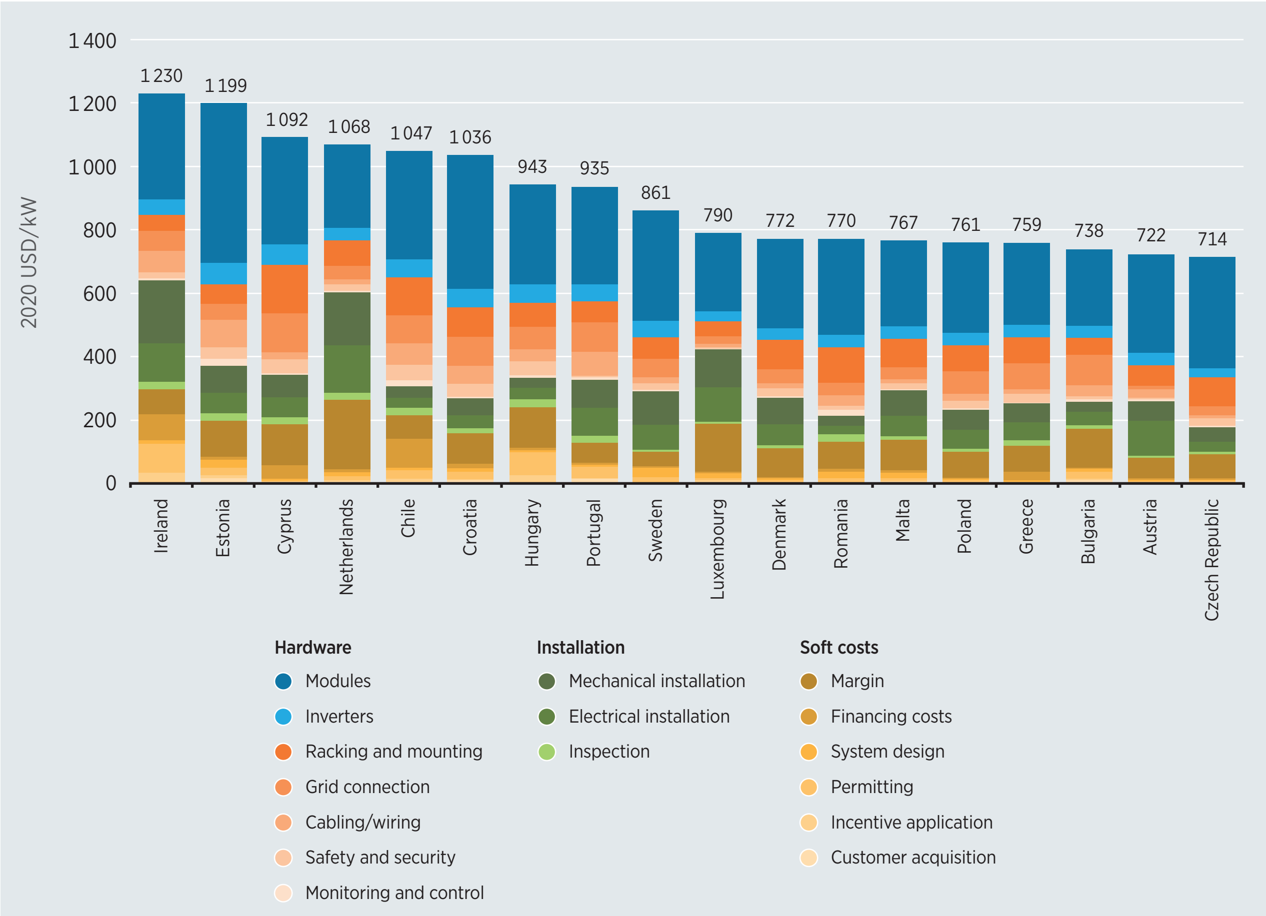
A better understanding of cost component differences amongst individual markets is crucial to understanding how to unlock further cost reduction potential. Obtaining comparable cost breakdown data, however, is often challenging. The difficulties relate to differences in the scale, activity and data availability of markets. Despite this, IRENA has expanded its coverage of this type of data, collecting primary cost breakdown information for additional utility-scale markets.

Adopting policies that can bring down BoS, and soft costs in particular, provides an opportunity to improve cost structures towards best practice levels. Reducing the administrative hurdles associated with the permit or connection application process is a good example of a policy that can unlock cost reduction opportunities. As markets continue to mature, it is expected that some of the cost differences among them will tend to decline.

In order to track these markets' development – and being able to devise targeted policy changes that address outstanding issues properly – a detailed understanding of individual cost components remains essential, however. In the subset of additional countries shown in Figure B3.6, BoS costs (excluding inverters) made up between 52% and 72%. On average, in this subset of the IRENA Renewable Cost Database, BoS costs represented 60% of the total installed costs.

Overall, BoS hardware costs made up between 17% and 53% of total BoS costs in those markets. On average, these hardware costs contributed around 40% of the total BoS costs and 18% of the total installed costs. Installation costs in these countries contributed between 14% and 48% of BoS costs. This means that on average, 30% of BoS costs and 18% of total installed costs related to installation cost categories. Soft costs made up for between 22% and 42% in this dataset. On average, soft cost items made up 30% of the total BoS cost. This represents a contribution of 18% to the total installed costs in these increasingly competitive markets.

**Figure 3.6** Detailed breakdown of utility-scale solar PV total installed costs in selected European countries and Chile, 2020




*Source: IRENA Renewable Cost Database*

Since 2010, in the residential PV sector, a declining cost trend in installed costs has also been visible in a wide range of countries. The residential, rooftop solar PV market has generally higher costs than utility-scale market, due to the smaller scale of its systems. Depending on the market, the total installed system costs (Table 3.1) decreased from between USD 4 326/kW and USD 7 844/kW in 2010, to between USD 658/kW and USD 4 236/kW in 2020 – a decline of between 46% and 85%. Since 2013, data for more markets beyond the early-adopter markets has also become available.

Compared to Germany, long the benchmark for competitive small-scale systems, residential system costs since 2013 have generally remained within twice the German cost level (except for France in 2013 and the US markets). Since 2013, however, India has become the new benchmark for the lowest-cost residential systems, although it was then joined by China in 2019. Between 2013 and that year, costs in the reported markets remained between two-and-a-half times and three times those of India, except in the US markets. There, they were between three and five times higher in that period. Residential solar PV total installed costs in India declined 73% between 2013 and 2020, while the reduction in less competitive markets has been slower. During 2020, this resulted in costs in Japan, the United Kingdom and Switzerland being between 3.3 and 3.8 times those of India, while residential costs in US markets were between 5.3 and 6.4 higher than in India.

The total installed system costs in the commercial markets shown in Table 3.1 decreased from between USD 5 466/kW and USD 8 632/kW in 2010 to between USD 651/kW and USD 2 974/kW in 2020 (a decline of between 69% and 88%). Since 2017, more data has become available, as new markets have emerged. Between 2017 and 2020, commercial costs in all the markets evaluated declined between 12% – in the United Kingdom – and 55%, in Brazil. An exception to this was New York, where costs have remained stubbornly high. During the 2017-2020 period, total installed costs have not exceeded two-and-a-half times those in India in any other commercial market, except for in the United States and Japan.

**Table 3.1** Residential and commercial sector solar PV total installed cost by country or state, 2010-2020

| Sector | Market | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | 2020 USD/kW | | | | | | | | | | |
| Residential | Australia | 7 803 | 6 196 | 4 350 | 3 712 | 3 463 | 2 223 | 2 011 | 1 758 | 1 575 | 1 307 | 1 219 |
| | Brazil | | | | 3 992 | 3 699 | 3 497 | 2 694 | 2 150 | 1 623 | 1 308 | 982 |
| | China | | | 2 856 | 2 460 | 2 356 | 1 692 | 1 609 | 1 453 | 1 091 | 850 | 746 |
| | France | | 9 909 | 7 029 | 5 839 | 4 280 | 2 386 | 2 199 | 1 989 | 1 935 | 1 875 | 1 840 |
| | Germany | 4 326 | 3 676 | 2 743 | 2 442 | 2 254 | 1 770 | 1 723 | 1 664 | 1 766 | 1 608 | 1 609 |
| | India | | | | 2 401 | 2 301 | 1 518 | 1 341 | 1 105 | 926 | 850 | 658 |
| | Italy | 7 028 | 6 176 | 4 077 | 3 702 | 2 466 | 2 006 | 1 823 | 1 695 | 1 544 | 1 477 | 1 357 |
| | Japan | 7 397 | 7 311 | 6 308 | 4 654 | 3 814 | 3 351 | 2 960 | 2 716 | 2 388 | 2 276 | 2 192 |
| | Malaysia | | | | 2 903 | 2 893 | 2 451 | 2 252 | 1 813 | 1 483 | 1 205 | 1 083 |
| | Republic of Korea | | | | 3 071 | 3 091 | 2 190 | 2 102 | 1 726 | 1 544 | 1 456 | 1 196 |
| | South Africa | | | | 4 187 | 3 726 | 3 145 | 2 950 | 2 631 | 2 256 | 1 864 | 1 575 |
| | Spain | | | | 2 903 | 2 466 | 1 778 | 1 652 | 1 526 | 1 462 | 1 426 | 1 397 |
| | Switzerland | | | | 3 908 | 3 480 | 3 253 | 3 196 | 3 118 | 2 786 | 2 582 | 2 516 |
| | Thailand | | | | 4 065 | 3 156 | 2 830 | 2 757 | 2 389 | 1 966 | 1 488 | 1 354 |
| | United Kingdom | | | | 3 338 | 3 514 | 3 041 | 2 699 | 2 723 | 2 627 | 2 465 | 2 218 |
| | California (US) | 7 844 | 7 409 | 6 395 | 5 537 | 5 214 | 5 290 | 5 111 | 4 581 | 4 343 | 4 164 | 4 236 |
| | Other US states | 7 793 | 7 130 | 5 762 | 4 977 | 5 010 | 4 981 | 4 328 | 3 888 | 3 744 | 3 675 | 3 520 |
| Commercial | Australia | | | | | 2 879 | 2 247 | 1 979 | 1 694 | 1 580 | 1 384 | 1 282 |
| | Brazil | | | | | | | 2 151 | 1 583 | 1 242 | 984 | 710 |
| | China | | 3 230 | 2 524 | 2 142 | 1 680 | 1 419 | 1 299 | 1 240 | 947 | 769 | 691 |
| | France | 8 632 | 4 193 | 2 922 | 2 966 | 2 913 | 2 288 | 1 876 | 2 163 | 2 022 | 1 697 | 1 348 |
| | Germany | | 3 536 | 2 284 | 1 949 | 1 710 | 1 282 | 1 369 | 1 305 | 1 274 | 1 127 | 1 136 |
| | India | | | | | | | | 1 021 | 912 | 827 | 651 |
| | Italy | 5 466 | 4 663 | 2 630 | 2 076 | 2 039 | 1 589 | 1 459 | 1 326 | 1 194 | 1 153 | 1 067 |
| | Japan | | | 5 298 | 4 260 | 3 158 | 2 449 | 2 382 | 2 295 | 2 100 | 2 003 | 1 717 |
| | Malaysia | | | | | 2 680 | 1 906 | 1 838 | 1 285 | 1 065 | 932 | 881 |
| | Republic of Korea | | | | | | | | 1 663 | 1 462 | 1 305 | 1 060 |
| | Spain | | 4 354 | 3 799 | 3 559 | 3 204 | 1 453 | 1 437 | 1 263 | 1 153 | 1 092 | 849 |
| | United Kingdom | | | | | | | 1 906 | 1 750 | 1 681 | 1 572 | 1 545 |
| | Arizona (US) | 7 112 | 6 289 | 5 542 | 4 391 | 3 615 | 3 878 | 3 476 | 3 143 | 2 718 | 2 782 | 2 600 |
| | California (US) | 6 565 | 6 338 | 5 027 | 4 687 | 3 710 | 3 610 | 3 739 | 3 545 | 3 234 | 3 132 | 2 974 |
| | Massachusetts (US) | 7 014 | 6 387 | 5 029 | 4 277 | 4 050 | 3 748 | 3 662 | 3 100 | 3 041 | 3 077 | 2 726 |
| | New York (US) | 7 389 | 6 624 | 5 538 | 4 296 | 3 829 | 3 540 | 3 291 | 2 860 | 2 709 | 2 677 | 2 815 |

*Source: IRENA Renewable Cost Database*

## CAPACITY FACTORS

By year commissioned, the global weighted-average capacity factor[3] for new utility-scale solar PV increased from 13.8% in 2010 to 16.1% in 2020. This factor showed an increasing trend between 2010 and 2018, when it reached its highest value so far, at 17.9%. This was predominantly driven by the increased share of deployment in sunnier locations. Since then, the growth trend has reversed. The 95$^{th}$ percentile value of the capacity factor declined significantly, from 27.0% in 2018 to 20.8% in 2020. The decline in the 5$^{th}$ percentile value was not as stark, however. (Table 3.2).

The development of the global weighted-average capacity factor is a result of multiple elements working at the same time.

Higher capacity factors in previous years have been driven by elements such as: the shift in deployment to regions with higher irradiation; the increased use of tracking devices in the utility-scale segment in large markets; and a range of other factors that have made a smaller contribution (*e.g.,* a reduction in system losses).

These concurring factors, however, often develop differently by market and can therefore have a varying impact on the weighted-average capacity factor. For example, available data for the United States, in particular, documents the increased use of trackers and their impact on capacity factors. It has been reported that tracking made up 69% of the capacity installed in United States in 2018, up from 26% in 2010 (Bolinger *et al.*, 2019). The prevalence of trackers in other major utility markets and how this has developed with time, however, has not been sufficiently documented yet, to understand its impact on global capacity factor values.

A trend towards higher inverter load ratios (ILRs) is also complicating comparisons in some cases. In the United States, for example, the median ILR grew about 9% between 2010 and 2019 to reach 1.31 in 2019. Depending on the context, increasing the DC array

**Table 3.2** Global weighted-average capacity factors for utility-scale PV systems by year of commissioning, 2010–2020

| Year | 5$^{th}$ percentile | Weighted average | 95$^{th}$ percentile |
|---|---|---|---|
| **2010** | 10.4% | 13.8% | 23.0% |
| **2011** | 10.1% | 15.2% | 26.0% |
| **2012** | 10.5% | 15.1% | 25.3% |
| **2013** | 11.9% | 16.4% | 23.0% |
| **2014** | 10.8% | 16.6% | 24.4% |
| **2015** | 10.8% | 16.5% | 29.0% |
| **2016** | 10.7% | 16.7% | 25.9% |
| **2017** | 11.5% | 17.5% | 27.0% |
| **2018** | 12.3% | 17.9% | 27.0% |
| **2019** | 10.7% | 17.5% | 23.9% |
| **2020** | 9.9% | 16.1% | 20.8% |

*Source: IRENA Renewable Cost Database*

*Note: These capacity factors are the AC-to-DC capacity factors, given that installed cost data in this report for solar PV (only) are expressed as per kilowatt DC.*

3 *The capacity factor for PV in this chapter is reported as an AC/DC value. For other technologies in this report, the capacity factors are expressed in AC-to-AC terms. More detailed explanations of this can be found in Bolinger and Weaver, 2014; Bolinger et al., 2015.*

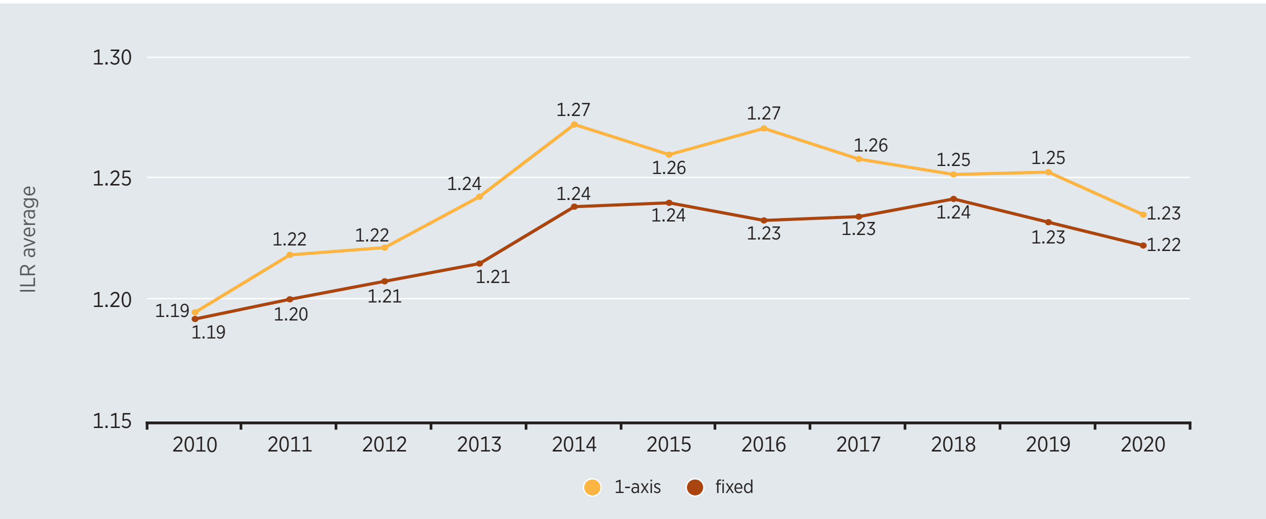
relative to the AC inverter capacity to achieve a higher ILR (also known as the DC/AC ratio) can be beneficial in reducing yield variability and enhancing revenue, depending on the context (Good and Johnson, 2016). The choice of the ILR is a system design consideration and is often influenced by the type of tracking used in a given project.

In the United States, fixed-tilt projects recorded a median ILR of 1.31 in 2019. The corresponding value for tracked systems was 2% lower (Bolinger *et al.*, 2020). All things being equal, increasing ILR would result in a reduction in the AC/DC capacity factor. The combination of increased deployment in areas with favourable solar resource conditions and the increased use of tracking have likely outweighed the effect of increasing ILR in the weighted-average values for the capacity factor up until 2018. Since then, these factors appear to be balancing out. This may be the reason for a further decline of the capacity factor value in 2020, after it had stayed at a relatively stable level – between 17.5% and 17.9% – in the previous two years. Better data is needed on ILR ratios globally, however, in order to be able to better assess these trends.

To help address the need to increase knowledge in global ILR trends, IRENA has collected ILR data from 2010 to 2020. This has resulted in a global subset of the IRENA Renewable Cost Database, for which ILR data is now available, comprising 202 GW of capacity from 6 836 projects. The subset's analysis shows similarities to the well-documented ILR trend in the United States.

As with the United States dataset, ILR values in this global dataset increased steadily from 2010-2013. The global dataset shows further ILR growth up until 2014. Looking at the individual mounting types highlights some differences in the design considerations for each. For fixed tilt projects, the average ILR in the dataset increased from 1.19 in 2010 to 1.24 in 2015. The ILR remained within the range 1.23 to 1.24 for all the years between 2016 and 2019, though preliminary data shows it falling in 2020 to a value of 1.22. For 1-axis tracking systems, the values are, as expected, higher, since these technologies can typically benefit more from higher ILR values. After reaching a maximum value of 1.27 in both 2014 and 2016, 1-axis tracker PV plants have shown a declining trend in recent years, though have consistently stayed above the level of fixed tilted systems. In 2020, the average ILR for 1-axis tracked systems was 1.23 (Figure 3.7).

**Figure 3.7** Global average inverter load ratio trend, 2010-2020




*Source: IRENA Renewable Cost Database*

## Box 3.1 Battery storage cost trends in stationary applications

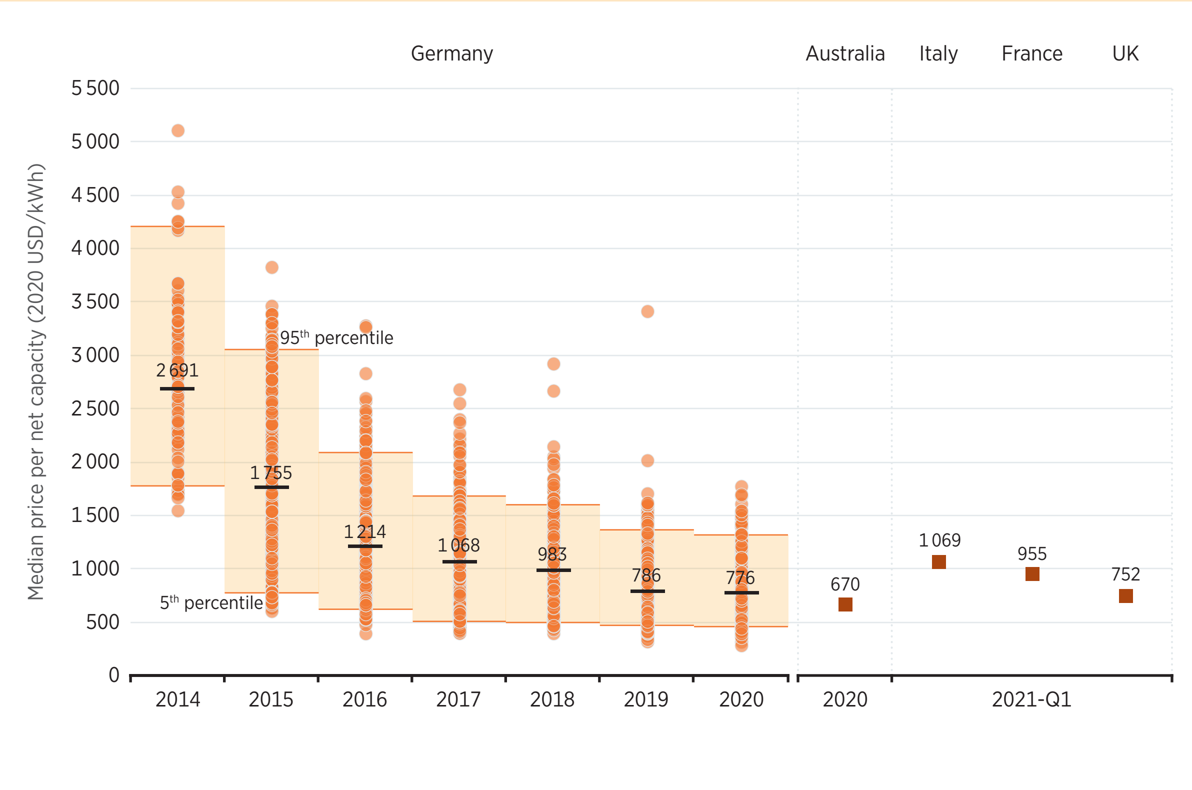
Electricity storage will play a crucial role in enabling the next phase of the energy transition. Battery storage will play a prominent role in decarbonising transport and the electricity system (IRENA, 2021b). Battery storage costs are falling rapidly and as they do, the range of services they can economically provide expands (IRENA, 2017a). The cost of battery systems for stationary applications are more expensive than those used for mobile applications due to the additional pack and battery management system costs required for managing more challenging charge/discharge cycles to which they are subjected (IRENA, 2017a).

Robust data for utility-scale battery cost reductions are not widely available. However, at the end of 2018, the United States had installed a utility-scale battery capacity of 869 MW with 1 236 MWh of electricity storage capacity. Between 2015 and 2018, the cost of utility-scale battery storage in the United States fell by 71% from USD 2 152/kWh to USD 635/kWh in the United States (U.S. EIA, 2020). This cost decline predominantly reflects the rate of decline in costs for lithium-ion batteries, given that they represented 90% of total installed battery capacity.

A real growth market has become small-scale, behind-the-meter battery storage systems coupled with rooftop solar PV in residential and commercial buildings. Time series data for small-scale residential battery systems in the German market suggest that prices also fell, coincidentally, by 71%, but between 2014 and 2020, with prices in 2020 of USD 776/kWh (Figure B3.1).

Data for Australia suggest prices somewhat lower than those experienced in Germany for small-scale residential battery storage systems, while the United Kingdom also experiences slightly lower prices. Battery storage systems in Italy and France are somewhat more expensive, which matches the experience in these countries with rooftop solar PV pricing.

**Figure B3.1** Behind-the-meter residential lithium-ion battery system prices in Germany, Australia, France, Italy and the United Kingdom, 2014-2020




*Source: IRENA and EUPD Research GmbH, 2021; and Solar Choice, 2021*

## OPERATION AND MAINTENANCE COSTS

The operation and maintenance (O&M) costs of utility-scale solar PV plants have declined in recent years, driven by module efficiency improvements, which have reduced the surface area require per MW of capacity.

At the same time, competitive pressures and improvements in the reliability of the technology have resulted in system designs that are optimised to reduce O&M costs. Improved O&M strategies that take advantage of a range of innovations have also driven down O&M costs and reduced downtime. Such innovations stretch from robotic cleaning to 'big data' analysis of performance to identify issues and preventative interventions ahead of failures.

For the period 2018-2020, O&M cost estimates for utility-scale plants in the United States have been reported at between USD 10/kW/year and USD 18/kW/year (Wiser *et al.*, 2020; Bolinger *et al.*, 2019; Bolinger *et al.*, 2020; EIA, 2020; NREL, 2018; Walker *et al.*, 2021). Recent costs in that country seem to be dominated by preventive maintenance and module cleaning, with these making up as much as 75% and 90% of the total, depending on the system type and configuration. The rest of the O&M costs can be attributed to unscheduled maintenance, land lease costs and other component replacement costs.

Average utility-scale O&M costs in Europe have been recently reported at USD 10/kW per year (Steffen *et al.*, 2020; Vartiainen et al., 2019), with historical data for Germany suggesting O&M costs came down 85% between 2005 and 2017, to USD 9/kW per year. This result suggests there has been a reduction of between 15.7% and 18.2% with every doubling of the solar PV cumulative installed capacity.

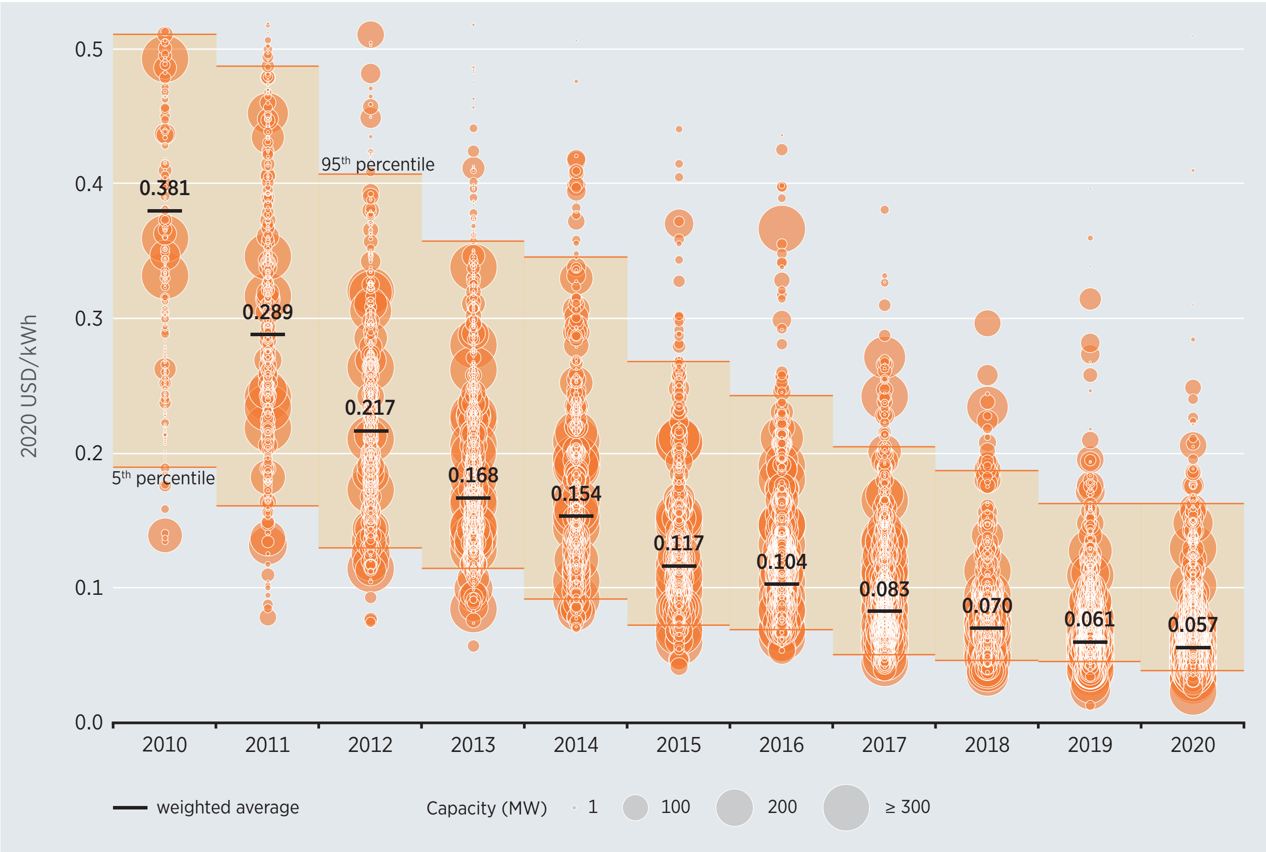
For 2020, the solar PV LCOE calculations in this IRENA report assume utility-scale O&M costs of USD 17.8/kW per year for projects commissioned in the Organisation of Economic Co-operation and Development (OECD) member countries (a 3% decline from 2019). For projects commissioned in non-OECD countries during that year, USD 9.0/kW per year is assumed (a decline of 5% from 2019)[4]. These are the estimated, total 'all-in' O&M costs, so include costs such as insurance and asset management, which are sometimes not reported in all O&M surveys.

*4 See Annex I for a more detail on O&M cost assumptions.*

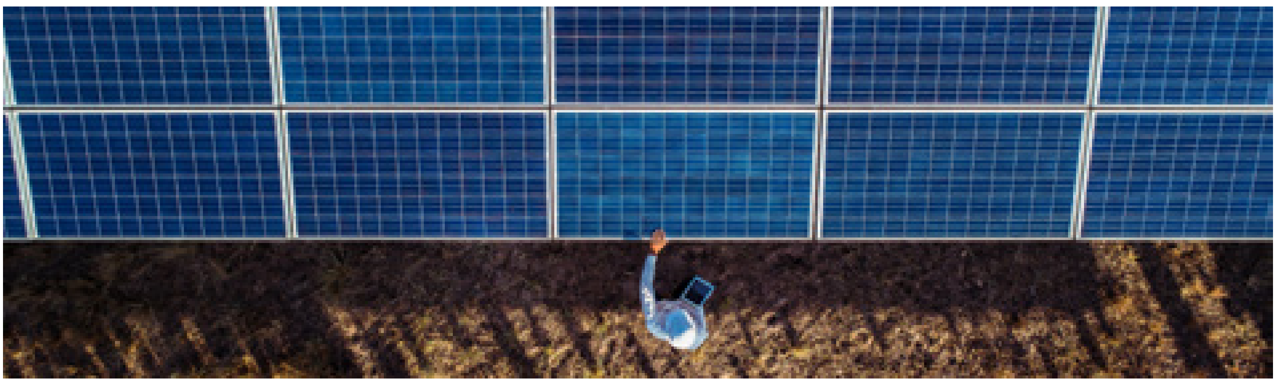
## LEVELISED COST OF ELECTRICITY

The global weighted-average LCOE of utility-scale PV plants declined by 85% between 2010 and 2020, from USD 0.381/kWh to USD 0.057/kWh. This 2020 estimate also represents a 7% year-on-year decline from 2019. Globally, too, the range of LCOE costs continues to narrow. The 5th and 95th percentile of projects in 2020 ranged from USD 0.039/kWh to USD 0.163/kWh, which is a 79% and 68% decline in the 5th and 95th percentile values, respectively, compared with 2010. After remaining flat during 2018 and 2019, the 5th percentile value declined 14% between 2019 and 2020, to reach USD 0.039/kWh. The 95th percentile value in 2020 remained flat from its value in 2019 (Figure 3.8).

**Figure 3.8** Global utility-scale solar PV project levelised cost of electricity and range, 2010-2020




*Source: IRENA Renewable Cost Database*



The rapid decline in total installed costs, increasing capacity factors and falling O&M cost have contributed to the remarkable reduction in the cost of electricity from solar PV and the improvement of its economic competitiveness (See Box B3.2)

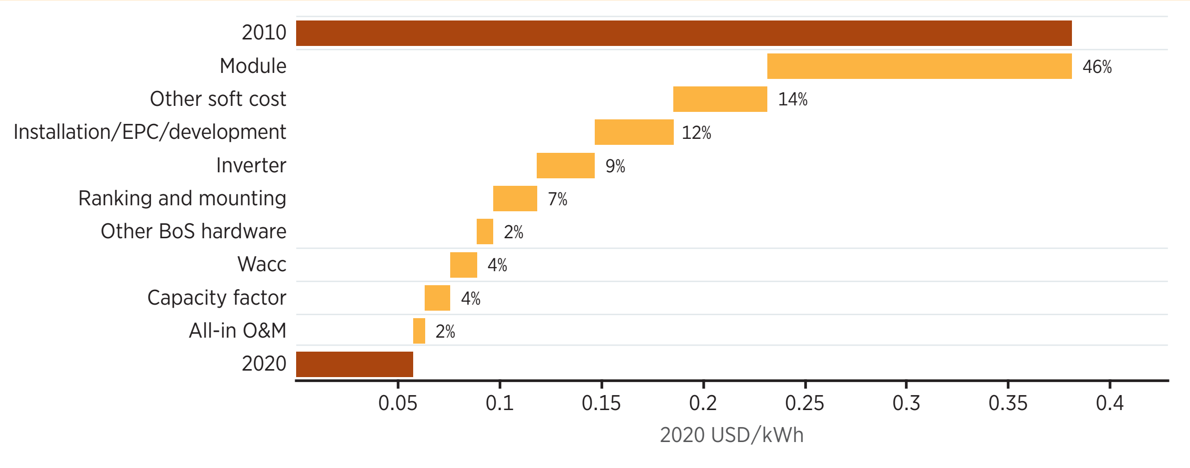
The downward trend in the LCOE of utility-scale solar PV by country is presented in Figure 3.9. Analysis of markets where historical data is available going back to 2010 shows that between then and 2020, the weighted-average LCOE of utility-scale solar PV declined by between 71% and 88%, depending on the country.

The largest reduction in the utility-scale sector could be observed in India, where between 2010 and 2020, costs declined by 85%, to reach USD 0.038/kWh – a value 33% lower than the global weighted average for that year, as reported in Figure 3.8.

## Box 3.2 Decomposing the decline in utility-scale LCOE from 2010 to 2020

The remarkable, sustained and dramatic decline in the cost of electricity from utility-scale solar PV is one of the more compelling stories of the last ten years in the power generation sector. In the last decade, the solar PV industry has experienced various technological developments that have contributed to improvements in the competitiveness of the technology. These have occurred along the whole solar PV value chain. From the increased adoption of larger polysilicon factories and improved ingot growth methods, to the increased ascendancy of diamond wafering methods and the emergence and dominance of newer cell architectures, the PV industry is constantly seeing innovations. Solar PV module costs have declined so rapidly that new solar PV markets keep emerging around the globe. The decline in solar module cost contributed 46% to the LCOE reduction of utility-scale PV between 2010 and 2020 (Figure B3.2). Together, cost reduction in inverters, racking and mountain and other BoS hardware, contributed another 18% to the LCOE reduction during that period. As solar PV technology has matured, the relevance of BoS costs has also increased, given the BoS share of total installed costs has tended to increase with time as module and inverter costs have historically decreased at a higher rate than non-module costs (IRENA, 2018). Installation, engineering, procurement and construction (EPC) and development costs combined with other soft costs were responsible for about a quarter of the LCOE decline. The rest of the reduction can be attributed to improved financing conditions as the markets matured, reduced O&M costs and an increased global weighted-average capacity factor driven by a shift to sunnier markets between 2010 and 2013.

**Figure B3.2** Drivers of the decline of LCOE of utility-scale solar PV (2010-2020)



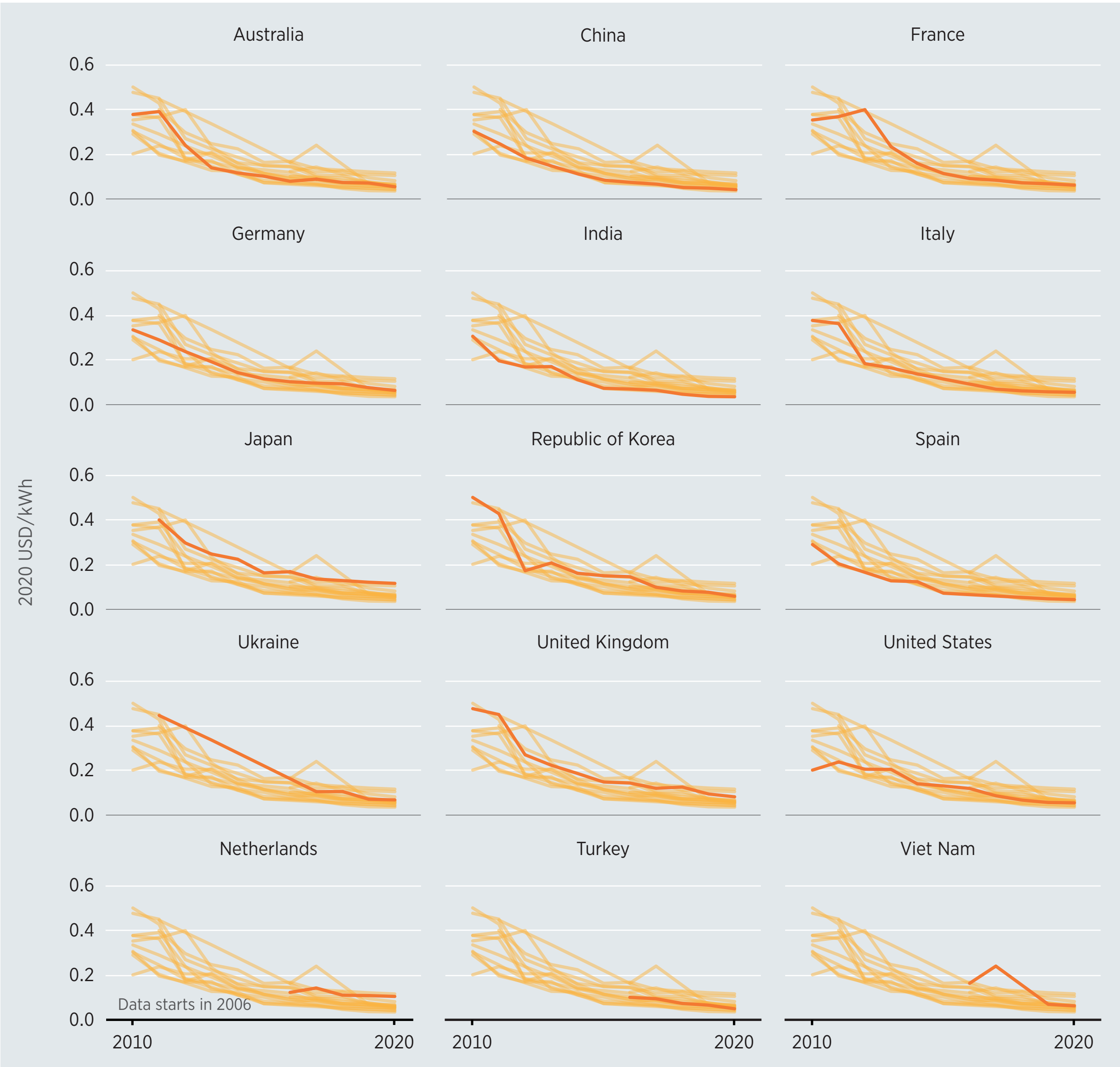

*Source: IRENA Renewable Cost Database*

After India, China and Spain achieved the most competitive LCOEs, with values of USD 0.044/kWh and USD 0.046/kWh respectively for 2020 (16% and a 22% higher than in India).

Beyond historical markets, important LCOE reductions have also occurred. For example, the LCOE in Turkey halved between 2016 and 2020, reaching a value of USD 0.052/kWh, some 8% below the global weighted average.

Driven by a 16% fall in total installed costs between 2019 and 2020, the LCOE of utility-scale PV in Australia declined 23% year-on-year, to reach USD 0.057/kWh during 2020. This put the 2020 LCOE of utility-scale PV in Australia at par with the United States. During 2020, the LCOE value in Japan declined 4% compared to 2019. Despite this, LCOE of utility-scale solar PV in Japan was around double that of India in 2020 (a ratio that remained unchanged from 2019).

**Figure 3.9** Utility-scale solar PV weighted average cost of electricity in selected countries, 2010-2020




*Source: IRENA Renewable Cost Database*

The LCOE of residential PV systems also declined steeply over the period. Assuming a 5% WACC,[5] the LCOE of residential PV systems in the markets shown in Table 3.3 declined from between USD 0.304/kWh and USD 0.460/kWh in 2010 to between USD 0.055/kW and USD 0.236/kWh in 2020 – a decline of between 49% and 82%.

Germany, a market that has been a major growth driver in residential solar PV over the last ten years, has very competitive total installed costs, yet relatively modest solar resources. The LCOE of German residential systems more than halved between 2010 and 2020, while the LCOE of residential costs in Japan declined 65% during the same period. During that decade, sharper reductions could be observed in historical markets with better resources, such as Italy and Australia. In Italy, the LCOE of residential systems declined by three-quarters between 2010 and 2020. Australia experienced an even sharper reduction, which at 79% was the highest among the markets reported in Table 3.3.

The data available from India, China, Australia, Spain, and Malaysia since 2013 shows that in these locations, which have good irradiation conditions and have experienced increasingly competitive total installed costs, very low LCOEs can be achieved. Between 2013 and 2020, in these low-cost markets, the LCOE range declined from between USD 0.133/kWh and USD 0.187/kWh to between USD 0.055/kWh and USD 0.103/kWh – a decline of between 45% and 59%.

At the same time, since 2017, the LCOE of residential PV systems in India, China and Australia has stayed below USD 0.097/kWh. During 2020, the most competitive residential PV LCOE costs occurred in India, at USD 0.055/kWh, with Chinese costs 14% higher. The LCOE of residential systems in Australia was a quarter higher than in India. Residential systems in Brazil and in Malaysia declined 17% and 7% between 2013 and 2020, respectively, to reach USD 0.0.089/kWh during 2020 (Table 3.3).

Between 2010 and 2020, the LCOE for commercial PV up to 500 kW declined between 50% and 79% in those historical markets where data is available (Italy, France and the US markets). During 2020, the LCOE in these markets ranged from USD 0.137 in France to USD 0.190/kWh in New York.

In 2020, the lowest average LCOE for commercial PV up to 500 kW could be found in India and China, at USD 0.055/kWh and USD 0.060/kWh, respectively (Table 3.3). Since 2017, India and China became more competitive in terms of the LCOE of commercial systems, after having undercut Australia – by then the reference LCOE benchmark for commercial systems. Between 2017 and 2020, the LCOEs in India and China fell 23% and 30%, respectively. In Australia, the LCOE value of commercial systems declined 18% during that period, to a 2020 value 30% higher than in India.

In addition to Australia, the LCOEs of commercial PV in Malaysia, Spain and Brazil were among the most competitive in 2020. They ranged between USD 0.075/kWh and USD 0.079/kWh and came within 5% and 10% of the cost of the LCOE of Australian commercial systems. The markets with the highest LCOE in 2020 were New York and Massachusetts, at USD 0.188/kWh and USD 0.190/kWh, respectively. The overall commercial PV LCOE range by market declined from between USD 0.262/kWh and USD 0.632/kWh in 2010 to between USD 0.063/kWh and USD 0.190/kWh in 2020 – a reduction of between 70% and 79%. Between 2019 and 2020, this range declined between 10% and 13%.

*5 This is lower than assumed values for utility-scale projects in all the other LCOE calculations in this report. This is based on the lower expected returns required by the owners of the assets in these sectors, where self-consumption is often a major driver.*

**Table 3.3** Residential and commercial sector solar PV levelised cost of electricity by country or state, 2010-2019

| Sector | Market | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | 2020 USD/ kWh | | | | | | | | | | |
| Residential | Australia | 0.322 | 0.260 | 0.189 | 0.165 | 0.155 | 0.107 | 0.099 | 0.089 | 0.082 | 0.072 | 0.069 |
| | Brazil | | | | 0.263 | 0.246 | 0.235 | 0.188 | 0.157 | 0.126 | 0.108 | 0.089 |
| | China | | | 0.164 | 0.145 | 0.140 | 0.108 | 0.104 | 0.097 | 0.079 | 0.068 | 0.063 |
| | France | | 0.720 | 0.522 | 0.440 | 0.333 | 0.203 | 0.190 | 0.176 | 0.172 | 0.168 | 0.165 |
| | Germany | 0.304 | 0.264 | 0.206 | 0.187 | 0.175 | 0.145 | 0.142 | 0.139 | 0.145 | 0.135 | 0.135 |
| | India | | | | 0.133 | 0.129 | 0.094 | 0.086 | 0.075 | 0.067 | 0.064 | 0.055 |
| | Italy | 0.409 | 0.363 | 0.250 | 0.230 | 0.163 | 0.139 | 0.129 | 0.122 | 0.114 | 0.110 | 0.104 |
| | Japan | 0.460 | 0.455 | 0.397 | 0.301 | 0.253 | 0.226 | 0.204 | 0.189 | 0.171 | 0.164 | 0.159 |
| | Malaysia | | | | 0.187 | 0.186 | 0.163 | 0.152 | 0.128 | 0.110 | 0.095 | 0.089 |
| | Republic of Korea | | | | 0.226 | 0.227 | 0.171 | 0.166 | 0.143 | 0.131 | 0.126 | 0.110 |
| | South Africa | | | | 0.202 | 0.182 | 0.157 | 0.149 | 0.136 | 0.120 | 0.103 | 0.091 |
| | Spain | | | | 0.183 | 0.160 | 0.123 | 0.117 | 0.110 | 0.107 | 0.105 | 0.103 |
| | Switzerland | | | | 0.307 | 0.277 | 0.262 | 0.258 | 0.252 | 0.230 | 0.216 | 0.211 |
| | Thailand | | | | 0.252 | 0.203 | 0.185 | 0.181 | 0.161 | 0.138 | 0.112 | 0.104 |
| | United Kingdom | | | | 0.330 | 0.345 | 0.305 | 0.276 | 0.278 | 0.270 | 0.256 | 0.236 |
| | California (US) | 0.309 | 0.293 | 0.256 | 0.224 | 0.212 | 0.215 | 0.209 | 0.189 | 0.180 | 0.174 | 0.176 |
| | Other US states | 0.307 | 0.283 | 0.233 | 0.204 | 0.205 | 0.204 | 0.180 | 0.164 | 0.158 | 0.156 | 0.150 |
| Commercial | Australia | | | | | 0.133 | 0.108 | 0.098 | 0.087 | 0.083 | 0.075 | 0.071 |
| | Brazil | | | | | | | 0.157 | 0.124 | 0.104 | 0.093 | 0.075 |
| | China | | 0.182 | 0.148 | 0.130 | 0.108 | 0.095 | 0.089 | 0.087 | 0.072 | 0.064 | 0.060 |
| | France | 0.632 | 0.327 | 0.240 | 0.243 | 0.239 | 0.196 | 0.168 | 0.187 | 0.178 | 0.155 | 0.131 |
| | Germany | | 0.255 | 0.177 | 0.156 | 0.142 | 0.115 | 0.120 | 0.116 | 0.114 | 0.105 | 0.106 |
| | India | | | | | | | | 0.071 | 0.066 | 0.063 | 0.055 |
| | Italy | 0.325 | 0.282 | 0.172 | 0.142 | 0.140 | 0.116 | 0.109 | 0.102 | 0.095 | 0.093 | 0.088 |
| | Japan | | | 0.339 | 0.279 | 0.215 | 0.174 | 0.170 | 0.165 | 0.154 | 0.148 | 0.132 |
| | Malaysia | | | | | 0.175 | 0.133 | 0.130 | 0.100 | 0.088 | 0.081 | 0.078 |
| | Republic of Korea | | | | | | | | 0.139 | 0.126 | 0.116 | 0.101 |
| | Spain | | 0.259 | 0.230 | 0.217 | 0.199 | 0.106 | 0.105 | 0.096 | 0.091 | 0.087 | 0.075 |
| | United Kingdom | | | | | | | 0.209 | 0.196 | 0.190 | 0.181 | 0.179 |
| | Arizona (US) | 0.282 | 0.252 | 0.224 | 0.182 | 0.154 | 0.163 | 0.149 | 0.136 | 0.121 | 0.123 | 0.116 |
| | California (US) | 0.262 | 0.254 | 0.206 | 0.193 | 0.157 | 0.153 | 0.158 | 0.151 | 0.140 | 0.136 | 0.130 |
| | Massachusetts (US) | 0.438 | 0.402 | 0.323 | 0.280 | 0.267 | 0.249 | 0.244 | 0.212 | 0.208 | 0.210 | 0.190 |
| | New York (US) | 0.444 | 0.401 | 0.340 | 0.271 | 0.245 | 0.229 | 0.215 | 0.191 | 0.183 | 0.181 | 0.188 |

*Source: IRENA Renewable Cost Database*

*Note: Unlike all other LCOE data presented in this report, the LCOE data in this table is calculated using a fixed, 5% WACC assumption.*

## Box 3.3 Electricity from solar PV in the Middle East at USD 0.01/kWh?

The year 2020 saw two[6] new record low bids for solar PV, following the trend of the last few years. In January 2020, the Qatar Electricity and Water Corporation (QEWC) announced it had awarded an 800 MW solar PV tender, with a contract duration of 25 years, at a price of USD 0.0157/kWh to a consortium of Total and Marubeni Corporation. This was surpassed in April, when the Emirates Water and Electricity Company (EWEC) announced a consortium of EDF and JinkoPower had secured a 2 GW of solar PV with a levelised price of USD 0.0135/kWh for a 30-year contract. This record managed to last out 2020, but was then eclipsed by the announcement in April 2021 that Saudi Arabia had awarded a 25-year contract for the 600 MW Al Shuaiba PV project, at USD 0.0104/kWh.

As has already been noted, care must be taken in comparing auction and PPA prices to LCOE values. Boundary conditions may not match, while often the full contract details are not available, meaning there could be additional payments or opportunities to raise revenue beyond the headline PPA price. The question thus arises as to whether these auction values resemble an LCOE value that we might expect for projects that will be commissioned in 2022 or beyond, around the region.

Before answering, however, it is worth highlighting the factors that will drive very low costs for these projects. These include:

- **Economies of scale:** Of the three projects, the smallest is 600 MW, while all three are single site projects.[7] The ability of project developers to secure the most competitive prices possible for services and hardware should not be underestimated.
- **Experienced and competitive civil engineering:** The region is home to a large, experienced civil engineering cadre of companies that understands large projects and will compete aggressively for contracts.
- **Competitive O&M structures:** Although data is sparse, O&M costs are expected to match the competitive values seen on the Indian sub-continent – or perhaps be even lower, given the increasing use of large amounts of data for preventative O&M, the use of drones for inspection and automated cleaning.
- **Long-term contracts, with low-risk off-takers:** The standard contract duration is 25 years, with, as we have seen, 30-year contracts also emerging, amortising costs over a longer period. The off-takers, being government owned, are also at low risk of default. This will reduce financing costs.
- **Consortiums including large multi-nationals:** These have extremely strong quality assurance processes, access to a wealth of experience and strong balance sheets. The presence of module manufacturers will also potentially help reduce equipment costs.
- **Stable exchange rates and low interest rates:** With currencies pegged to the USD, companies do not have to deal with the potential impact of volatile local currency exchange rates. Given their financial reserves and perceived low risk, these projects also face very low interest rates (the credit default swap for the United Arab Emirates is 0.4% – lower than that for the United Kingdom, at 0.5%).[8]
- **Excellent solar resources:** The region has excellent solar resources and bifacial modules with single axis trackers might yield capacity factors of up to 27% with an ILR of 1.3. Saudi Arabia in particular has very high solar irradiation in many parts of the west of the country, giving it a non-negligible advantage over its neighbours along the coast of the Gulf.

Given these contracts are close to our LCOE boundary conditions (*e.g.,* indexed to inflation, contract durations of 25-30 years), is there a plausible set of LCOE parameters that would generate these very low LCOE values?

*6 This excludes Portugal's record low value for just 10 MW of capacity. Given the bids, for several reasons, this was unlikely to reflect LCOE values.*

*7 For comparison, the average utility-scale project in Germany last year was 10 MW at an average total installed cost of USD 700/kW.*

*8 See Damodaran, 2020 for an explanation of how these figures are derived. The data can be downloaded at http://pages.stern.nyu.edu/~adamodar/New_Home_Page/datafile/ctryprem.html (accessed 3 June 2021).*

The answer appears, surprisingly, to be a qualified yes.

What is required to achieve these exceptionally low prices is the convergence of all of the factors that could drive costs to their lowest levels. Figure 3.7 presents the data for the LCOE of a utility-scale solar PV plant in the western part of Saudi Arabia. With bifacial modules and one axis trackers, this would yield a capacity factor of around 28%.

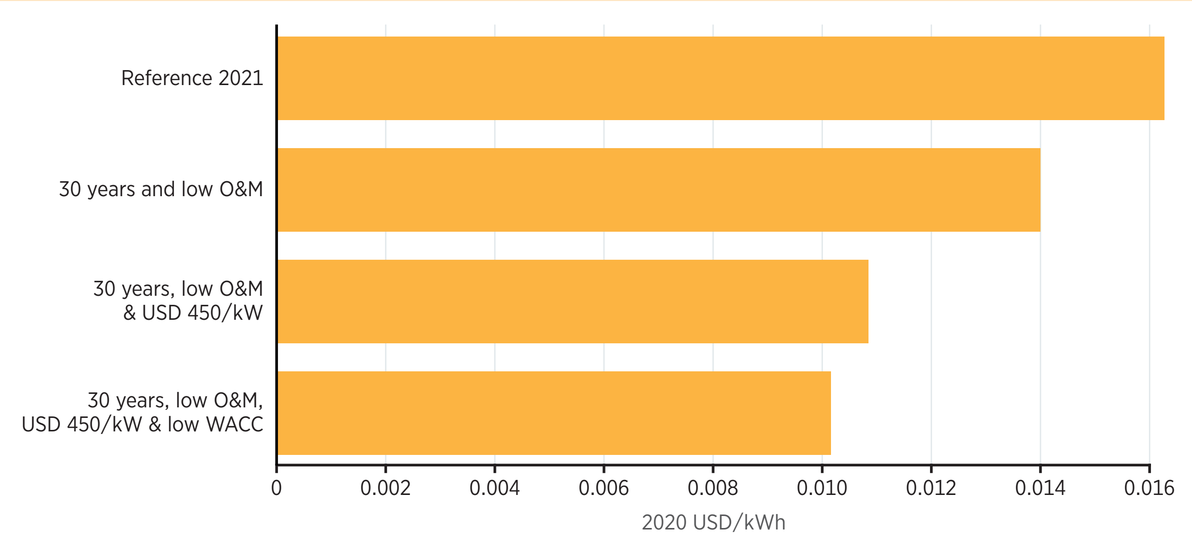
The reference plant commissioning in 2021, assumes that a large project of this type would have total installed costs of USD 550/kW, a 25 year economic life, O&M costs of USD 8 000/MW/year, and a real, after tax WACC of 3%.[9] Under these assumptions, the LCOE is USD 0.0163/kWh. Assuming a 30-year economic life and O&M costs of USD 6 000/MW/year, which might be feasible for such large projects using the latest O&M practices, the LCOE falls to USD 0.014/kW.

The LCOE of solar PV is most sensitive to the total installed cost and WACC assumptions, given the capacity factor is fixed. Reducing the total installed cost to USD 450/kW and the real, after tax WACC to 1.9% would yield an LCOE of USD 0.0101/kWh, very close to the announced price for the 600 MW Al Shuaiba PV project.

Total installed costs of USD 450/kW could be possible, for a project that will be commissioned in 2022. The benefits of economies of scale will be important, but much will depend on the massive plans for solar PV supply chain expansion in 2021 creating downward pressure on module prices.[10] Other important factors that could help are, it is not clear these projects will be responsible for grid connection costs (Apostoleris, Al Ghaferi and Chiesa, 2021), which could save in the order of USD 28/kW.[11] The up-front cost of arranging finance might also be expected to be below average, saving perhaps USD 5/kW to USD 35/kW. A real WACC of 1.9% might be possible in Saudi Arabia. Assuming a 1.5% lenders margin and – if project developers are prepared to accept this – a US equity return of around 6.4%, the real WACC would be 1.9%. In this context, it is worth noting that the nominal WACC in Germany for their smaller PV projects has previously been reported around this level, in nominal terms (Egli, *et al.*, 2018).

The transformational nature of a solar PV LCOE at USD 0.0104/kWh is a little hard to grasp. To put it in context, a coal-fired plant run at a 67% annual capacity factor – higher than what is now routinely achieved – would have the same LCOE contribution just from its fixed USD 60/kW/year O&M costs. It would have to run at 82%, however, when taking into account its variable O&M costs, which stand at around USD 0.002/kWh.

**Figure B3.3** Scenarios for utility-scale solar PV LCOE under different input assumptions in Saudi Arabia




*Source: IRENA Renewable Cost Database*

*9 A real WACC of 3% would be equivalent to assuming a nominal, risk-free rate of 2.3% for Saudi Arabia and a 2.2% lenders margin (with an effective corporate tax rate of 20%) and a nominal 9.9% return on equity (a 3.5% margin over the long-run US equity risk premium), along with an 80%/20% debt-to-equity ratio and 1.8% inflation.*

*10 See https://www.pv-magazine.com/2021/03/13/the-weekend-read-unprecedented-plans-and-investments-in-chinese-pv-production-capacity/ accessed 4 June 2021.*

*11 For projects commissioned in 2020, the estimated grid connection cost ranged from a low of USD 33/kW in India to USD 132/kW in France, with an estimate for Saudi Arabia of USD 28/kW.*

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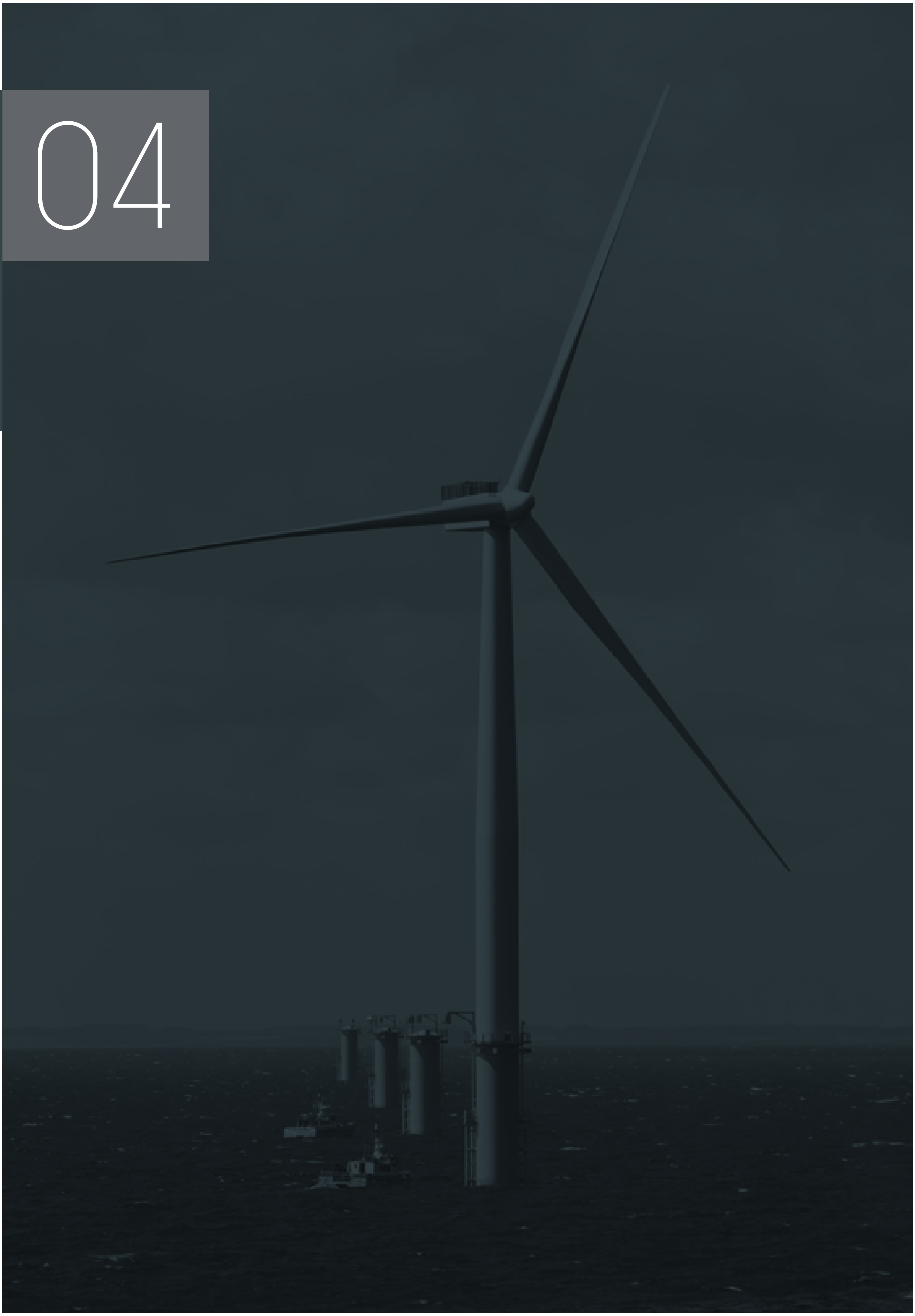
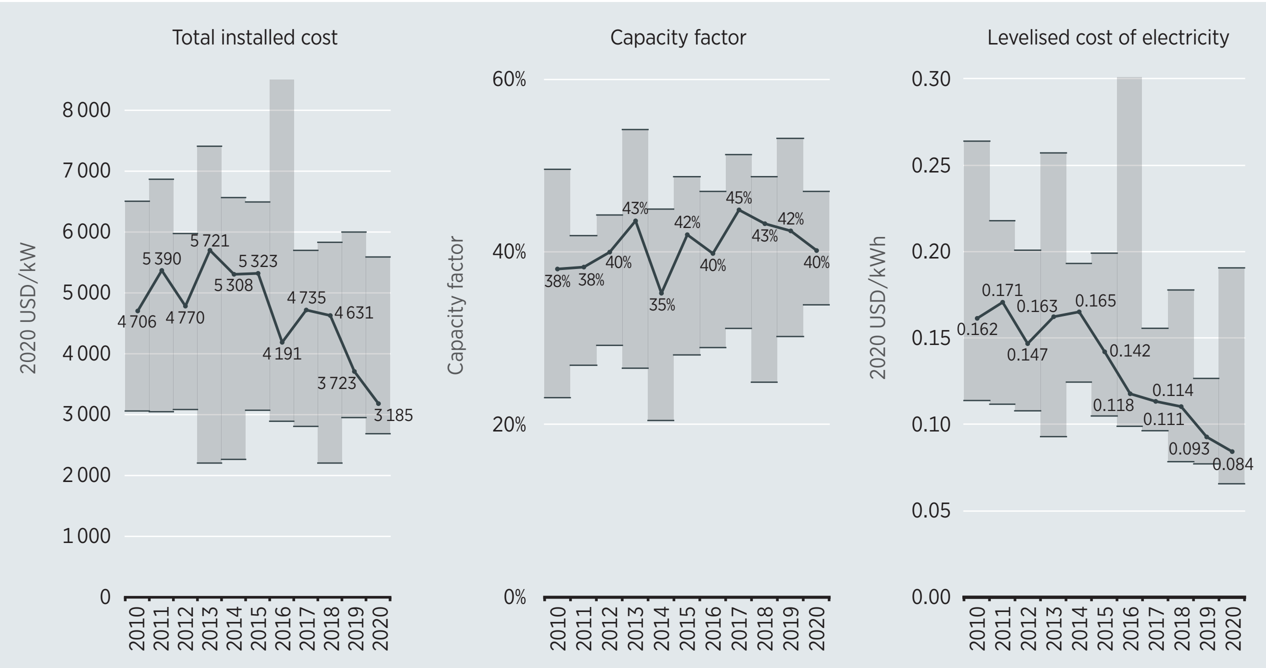


# OFFSHORE WIND

## HIGHLIGHTS

- The global weighted-average LCOE of offshore wind declined by 48% between 2010 and 2020, from USD 0.162 to USD 0.084/kWh, with a 9% reduction year-on-year in 2020. Auction and tender results suggest that from 2023, the cost of electricity will fall to between USD 0.05/kWh and USD 0.10/kWh, with these levels achievable even in relatively new markets.
- Between 2010 and 2020, global weighted-average total installed costs fell 32%, from USD 4 706/kW to USD 3 185/kW. The global weighted-average total installed cost peaked at USD 5 390/kW in 2011, representing a figure 41% higher than its 2020 value.
- Global cumulative installed capacity of offshore wind increased more than eleven-fold between 2010 and 2020, from 3.1 GW to 34.4 GW. This was almost equally driven by installations in China and Europe.
- Improvements in technology, including larger turbines, longer blades with higher hub heights and access to better wind resources, as from the shore wind farms moved further from the shore resulted in an increase in the global weighted-average capacity factor. This increased from 38% in 2010 to 45% in 2017, before dropping to 40% in 2020 as China increased its share in global deployment.
- Total installed cost and LCOE reductions have been driven by both technology improvements and the growing maturity of the industry. A range of factors, including developer experience, greater product standardisation, manufacturing industrialisation, regional manufacturing and service hubs, and economies of scale have all contributed to cost declines. This has been facilitated by clear deployment and, in many cases, manufacturing policies that have supported this growth and the benefits of scale evident in the industry today.

**Figure 4.1** Global weighted-average and range of total installed costs, capacity factors and LCOE for offshore wind, 2010-2020




*Source: IRENA Renewable Cost Database.*

## INTRODUCTION

Offshore wind was a relatively new and developing technology in 2010, but with the technology maturing rapidly, this has since changed. Indeed, there was an eleven-fold increase in cumulative deployed capacity between 2010 and 2020, from 3.1 gigawatts (GW) to 34.4 GW (IRENA, 2021a).

Currently, offshore wind makes up just under 5% of global wind (onshore and offshore) deployment. Yet, plans and targets for future deployment have been expanding, as costs decrease and the technology heads towards maturity. Annual capacity additions averaged over 5 GW between 2017 and 2020.

Unlike onshore wind projects, offshore wind farms must contend with installation and operation and maintenance (O&M) in harsh marine environments, making these projects costlier and giving them significantly longer lead times. The planning and project development required for offshore wind farms is more complex than that for onshore wind projects. Construction is even more so, increasing total installed costs. Given their offshore location, these projects also have higher grid connection and construction costs. Offshore wind project installed costs peaked around the period of 2011-2012, as projects were sited farther from shore, in deeper waters, and used more advanced technology.

*Cumulative offshore wind capacity has increased eleven-fold between 2010 to 2020, from 3.1 GW to 34.4 GW*

With the recent increase in deployment, cost reductions have been unlocked. This has been driven by technology improvements, economies of scale, and increases in developer and turbine manufacturer experience. However, the increasing maturity of the industry is also reflected in cost-saving programmes such as the standardisation of turbine and foundation designs, the industrialisation of manufacturing for offshore wind components in regional hubs, and the increasing sophistication and speed of installation practices. Installation times and costs per unit of capacity are falling with developer experience, the use of specialised ships designed for offshore wind work and increases in turbine size that amortise installation efforts for one turbine over ever-larger capacities.

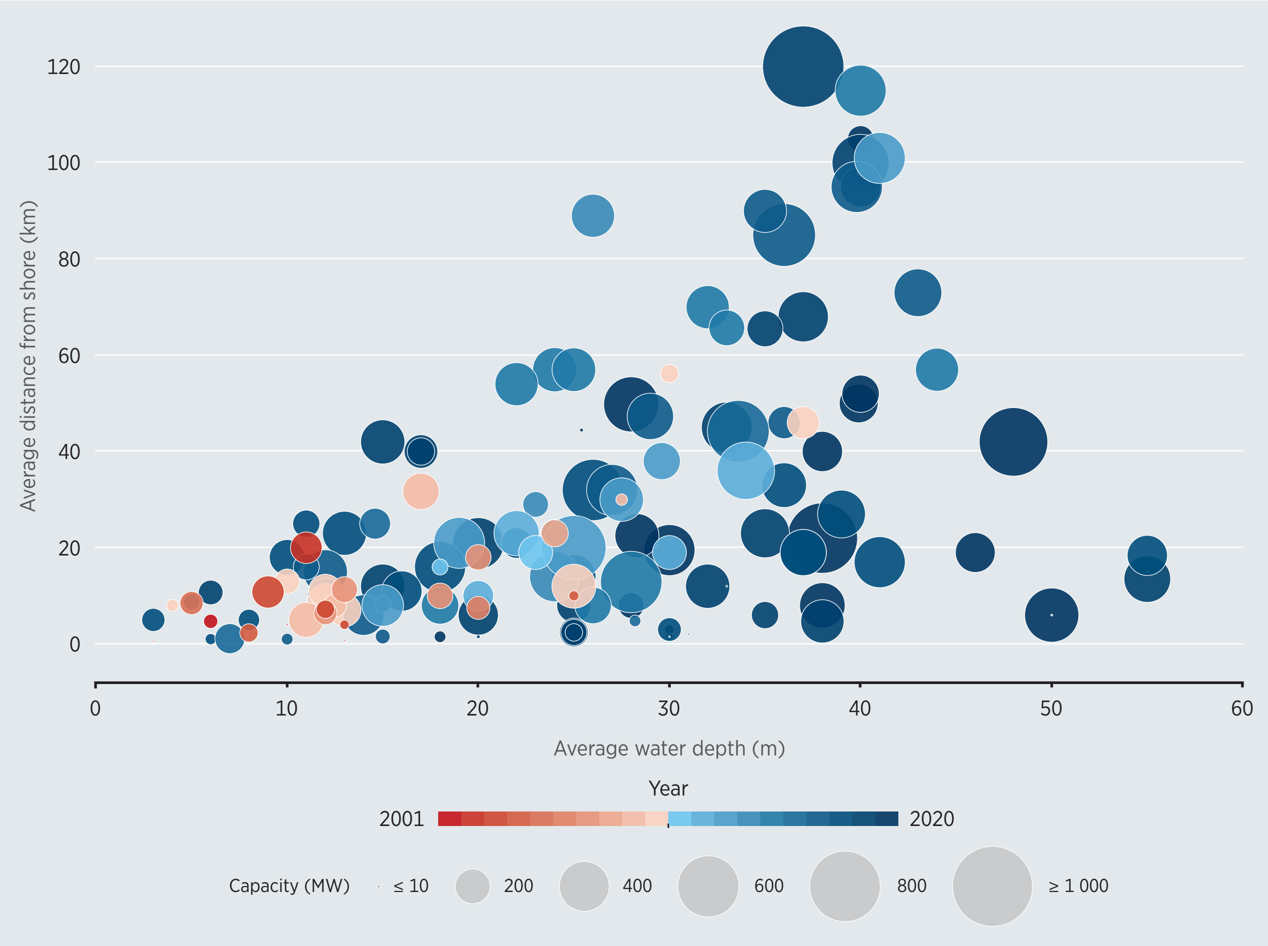
The introduction of specialised ships for maintenance has also helped lower O&M costs. However, the scale and optimisation benefits of servicing offshore wind farms zones, rather than individual wind farms, is also playing a role, as is the increased wind turbine availability as manufacturers are constantly learning from recent experience and incorporating improvements into newer products. An important area of improvement is also linked to the ongoing digitisation of the energy sector – the increasingly sophisticated use of a myriad of intelligence being generated from turbine performance data, allowing predictive maintenance programmes that are designed to intervene before costly failures – thereby contributing to lower O&M costs.

Figure 4.2 presents the trend that occurred between 2001 and 2020 in which offshore wind farms moved to deeper waters and farther from shore. The offshore wind farms commissioned in 2001 averaged 25 megawatts (MW) in size in a water depth of 7 metres (m), roughly 5 kilometres (km) from shore. These figures have significantly increased since then. In 2020, the average offshore windfarm sized reached 301 MW and had a weighted-average distance to shore and water depth of 30 km and 38 m, respectively, based on project data in the IRENA Renewable Cost Database.

The distance from a shore or port suitable for installation and water depth both impact total installed costs, given the return trips to port for foundations and turbines during installation and the size of the foundations. The distance to port also has an impact on O&M costs and decommissioning costs. In European waters, the trend to site wind farms farther from shore has also been correlated with harsher weather conditions making installation more difficult, and this has added time and cost to the already high logistical costs when projects are farther from ports (EEA, 2009). However, this impact has stabilised, even for the large wind farms that are now the norm in European waters. Installation costs are coming down with larger turbines, with installation times – from first foundation to commissioning – for wind farms in the IRENA Renewable Cost Database for which data are available declining to between 1.4 and 2.4 years since 2015.

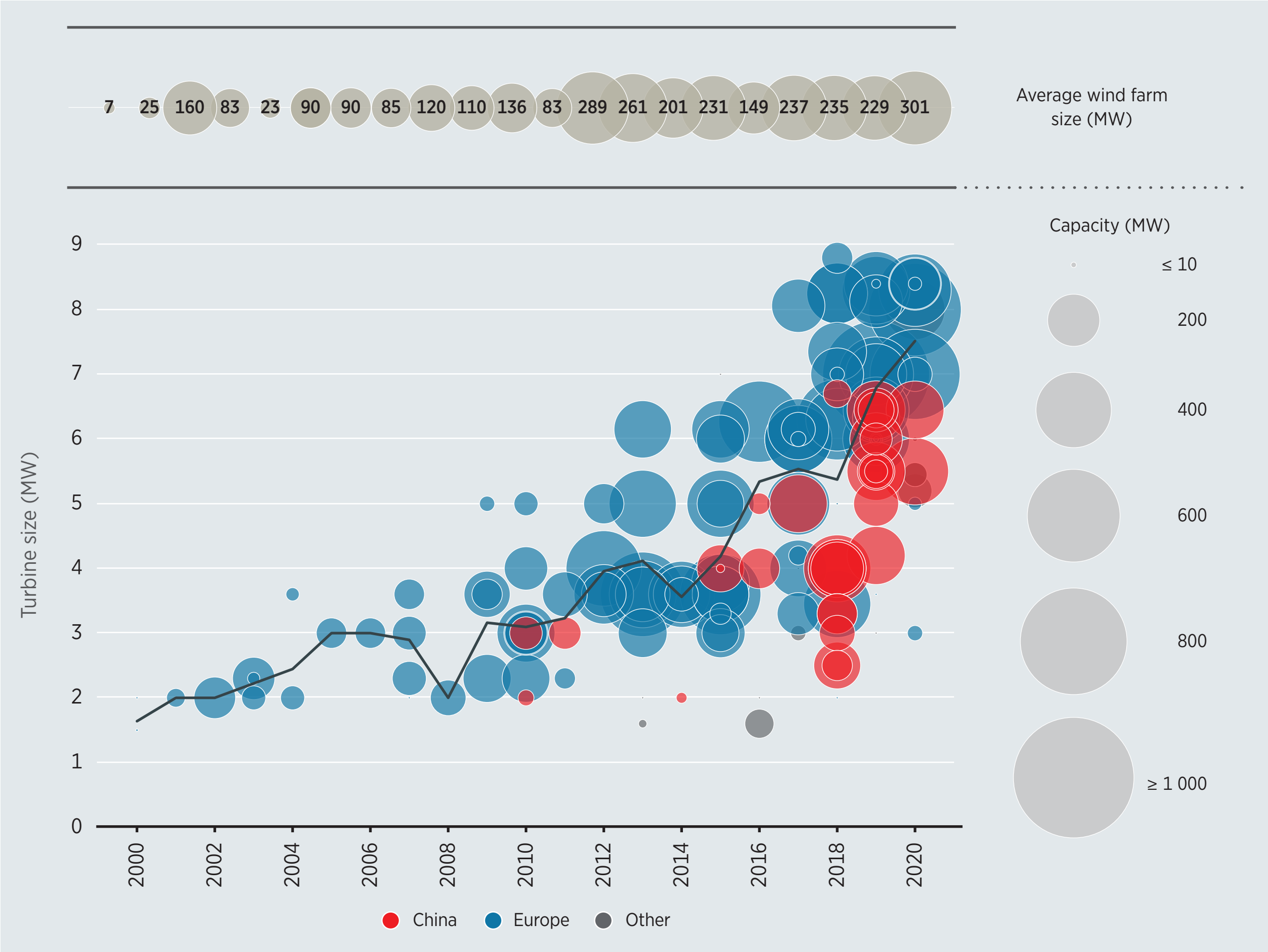
In addition to offshore wind farm installations increasingly being located farther from ports and anchored in deeper waters, there has also been a trend towards higher capacity turbines, with higher hub-heights and longer, more efficient and durable blades. These turbines, now specially designed for the offshore sector, increase energy capture. This is crucial in reducing the levelised cost of energy (LCOE) of offshore projects. The larger turbines also provide economies of scale, with a reduction in installation costs and an amortisation of project development and O&M costs (Figure 4.3).

**Figure 4.2** Average distance from shore and water depth for offshore wind, 2000-2020




*Source: IRENA Renewable Cost Database.*

**Figure 4.3** Project turbine size and global weighted-average turbine size and wind farm capacity for offshore wind, 2000-2020




*Source: IRENA Renewable Cost Database.*

Between 2010 and 2020, the weighted-average turbine capacity increased 150%, from 3 MW to 7.5 MW. Projects commissioned in 2020 had a turbine rating 15% higher than the average for 2019, 6.5 MW. Rotor diameters have increased at the same time as higher turbine ratings, the increase in rotor diameter is important, as this allows for higher energy capture from the turbines and smoother energy output over the year. This makes offshore wind particularly useful in reducing overall intermittency. Between 2010 and 2019, the weighted-average rotor diameter for deployments grew by 44%, from 112 m to 161 m, based on available data for active projects.

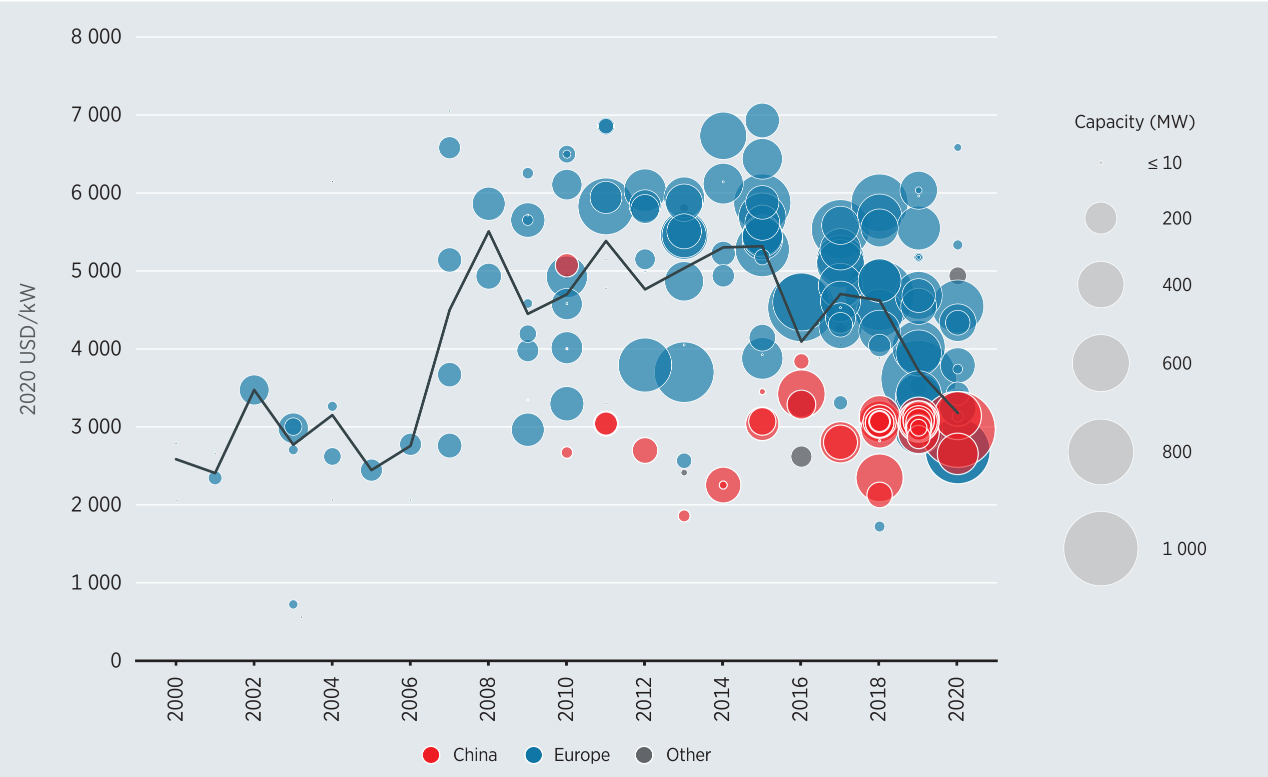
## TOTAL INSTALLED COSTS

Compared to onshore wind, offshore wind farms have higher total installed costs. Installing and operating wind turbines in the harsh marine environment offshore increases costs. Planning and project development costs are higher and lead times longer as a result. Data must be collected on seabed characteristics and the site locations for the offshore wind resource, while permitting and environmental consents are often more complex and time consuming. Logistical costs are higher the farther the project is from a suitable port, while greater water depths require more expensive foundations.

Offshore wind, however, has the advantage of economies of scale, meaning that some of these costs are not disproportionately higher than those for onshore wind. At the same time, the higher capacity factors offshore and the more stable wind output (due to higher average wind speeds and reduced wind shear and turbulence), which also coincides with winter demand peaks in Europe, ensure offshore wind output is of higher value to the electricity system than onshore wind. The promise of offshore wind has always been evident and, in the last few years, it has started to realise its potential from scaling. Between 2010 and 2020, the average offshore wind project size increased by 121%, from 136 MW to 301 MW. There are currently projects that began to be deployed in 2020 and beyond that have capacities exceeding 1 GW.

The global weighted-average total installed cost of offshore wind farms increased from around USD 2 592/kW (kilowatts) in 2000 to over USD 5 500/kW 2008, and bounced around the USD 5 000/kW for the period 2008 to 2015, as projects moved farther from shore and into deeper waters (Figure 4.4). The global weighted-average total installed cost began to decline after 2015, falling relatively rapidly to USD 3 185/kW in 2020.

**Figure 4.4** Project and weighted-average total installed costs for offshore wind, 2000-2020




*Source: IRENA Renewable Cost Database.*

A number of factors explain the increase in total installed costs that occurred after 2006, including:

- The shift to projects in deeper waters and farther from shore/ports increased logistical costs, installation costs and foundation costs.
- The increasing scale and complexity of projects required a proportional increase in project development costs (surveys, licensing, etc.).
- The industry was in its infancy, and the specialised installation vessels of today were not available, resulting in less efficient installation processes. Additionally, supply chains were not yet optimised, operating at scale and with widespread competition.
- Rising commodity prices in this period also had a direct impact on the cost of transportation and on the offshore wind materials used in turbines and their foundations, transmission cabling, and other components (IRENA, 2019).

Some of the contributing factors to cost increases, such as supply chain bottlenecks for turbines and cables and logistics issues, were transient (Green, 2011; Anzinger, 2015). Consequently, the weighted-average total installed costs have since followed a downward cost reduction trend, falling by 41% from their peak in 2011 to a global weighted-average of USD 3 185/kW for projects commissioned in 2020. Major support came from lower commodity prices, lower risks from stable government policies and support schemes, improved turbine designs, standardisation of design and industrialised manufacturing, improvements in logistics (especially with specialised installation vessels and larger turbines for offshore wind), and economies of scale from clustered projects in Europe. Yet, due to the relatively thin market compared to onshore wind and solar photovoltaic (PV), the global weighted-average total installed cost by year remains volatile.

The yearly volatility in total installed costs is due to the site-specific nature of offshore wind projects, the differences in market maturity, and the scale of the local or regional supply chain. Deployment in each year is distributed slightly differently across markets, and this can drive yearly volatility. In 2020, China dominated total deployment. The global weighted-average total installed costs are therefore heavily influenced by China's lower costs due to lower commodity prices and labour costs, as well as the near-shore and inter-tidal nature of most Chinese wind farms.

The most notable other driver of total installed costs is the party responsible for the wind farm-to-shore transmission assets. This choice varies by country. In some cases, the transmission assets are owned by the national or regional transmission network owner, and in other cases they are owned by the wind farm developer.[1]

Looking at the total installed cost trends by country is therefore important to understand how cost structures are evolving. China, which has the largest cumulative wind deployment globally (roughly 9 GW), experienced a decline in weighted-average total installed cost between 2010 and 2020 of 32% – from USD 4 476/kW to USD 2 968/kW (Table 4.1). In Denmark and China, the grid connection assets are developed and owned by public entities or the transmission network owner, lowering the project-specific installed costs. As a result, the project-specific weighted-average total installed costs

1 *Other arrangements are also possible. In the United Kingdom, the project developer is responsible for developing the transmission asset, which can then be owned by a third party.*

in 2020 were USD 2 963/kW in Denmark. In the Netherlands, which had the second largest offshore wind added capacity in 2020 (1.5 GW), its project-specific weighted-average total installed cost was in fact the lowest when compared to other markets, at USD 2 745/kW. All the regions and countries listed in Table 4.1 experienced a decrease in the weighted-average total installed costs in 2020. Belgium had the highest percentage decrease (44%) in weighted-average total installed cost between 2010 and 2020 – from USD 6 113/kW to USD 3 422/kW.

*The global weighted-average total installed cost of offshore wind fell 40% between 2015 and 2020, from USD 5 323/kW to USD 3 185/kW*

Offshore and onshore wind farms have differing cost breakdowns. This is to be expected with offshore wind farms' higher costs on average for installations and foundations. Data availability for project-level total installed costs is almost non-existent due to confidentiality issues. However, numerous studies provide estimates for specific markets, often based on discussions with project developers, although it is sometimes unclear exactly how comparable these data are. Offshore, turbines (including towers) generally account for between 33% and 43% of the total installed cost (Figure 4.5). Other costs, however – including installation, foundation, and electrical interconnection – are significant, and take up a sizeable share of the total installed costs. Installation costs, for the estimates available, range from 8% to 19% of total installed costs, while contingency/other costs range from 10-14%, electrical interconnection from 8-24% and foundation costs from 14-22%. Development costs, which include planning, project management and other administrative costs, comprise up to 2-7% of total installed costs. Offshore wind site characteristics and country policies can also account for differences in cost breakdowns. In China, Denmark and the Netherlands, for example, developers are not responsible for electrical interconnection costs (besides the cost of electrical arrays for connecting the turbines).

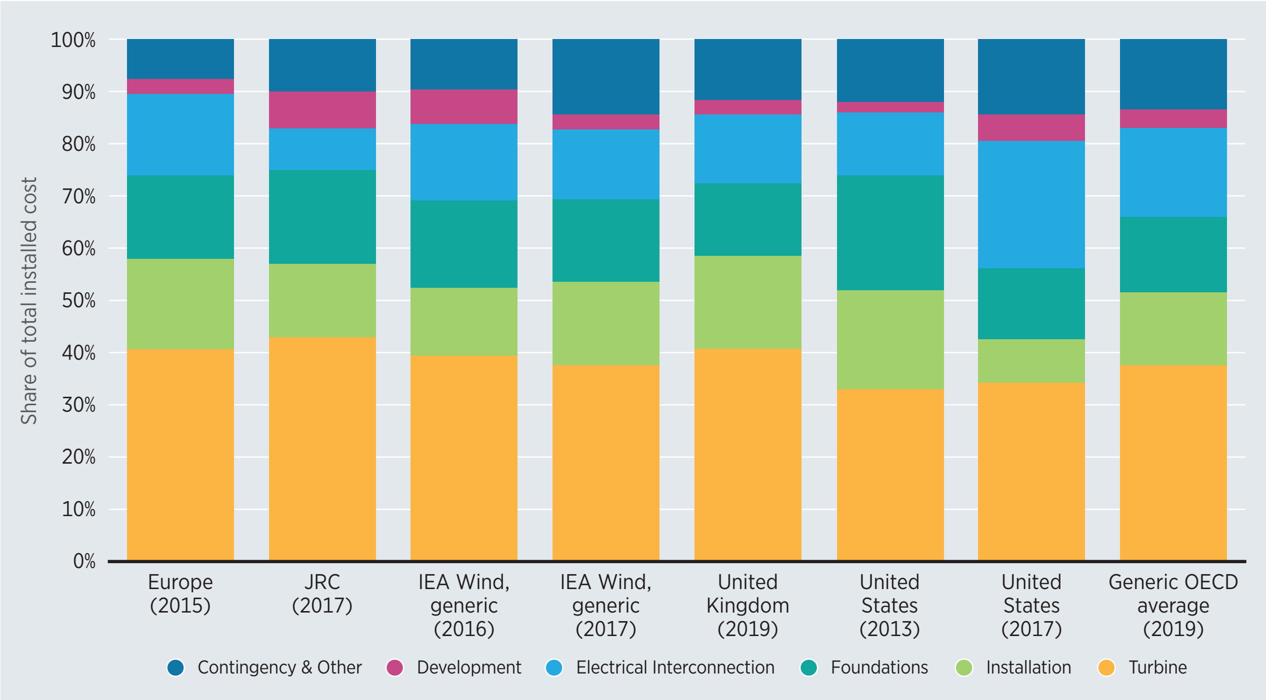
**Table 4.1** Regional and country weighted-average total installed costs and ranges for offshore wind, 2010 and 2020

| | 2010 | | | 2020 | | |
|---|---|---|---|---|---|---|
| | 5th percentile | Weighted average | 95th percentile | 5th percentile | Weighted average | 95th percentile |
| | (2020 USD/kW) | | | | | |
| **Asia** | 2 877 | **4 517** | 5 058 | 2 707 | **3 001** | 4 675 |
| China | 2 810 | **4 476** | 4 972 | 2 691 | **2 968** | |
| Japan* | 4 935 | **4 935** | 4 935 | 4 959 | **4 959** | 4 959 |
| Republic of Korea | n.a. | **n.a.** | n.a. | 4 944 | **4 944** | 4 944 |
| **Europe** | 3 555 | **4 713** | 6 504 | 2 696 | **3 394** | 5 840 |
| Belgium | 6 113 | **6 113** | 6 113 | 3 254 | **3 422** | 3 741 |
| Denmark* | 3 303 | **3 303** | 3 303 | 2 963 | **2 963** | 2 963 |
| Germany | 6 504 | **6 504** | 6 504 | 3 523 | **4 143** | 4 336 |
| United Kingdom | 4 078 | **4 588** | 4 895 | 4 552 | **4 552** | 4 552 |
| Netherlands | n.a. | **n.a.** | n.a. | 2 696 | **2 745** | 6 201 |

*Source: IRENA Renewable Cost Database.*

** Countries with data only for projects commissioned in 2019*

**Figure 4.5** Representative offshore wind farm total installed cost breakdowns by country/region, 2013, 2016, 2017 and 2019




*Source: IRENA Renewable Cost Database, BVG Associates (2020), IEA Wind (2018), Crown Estates and BVG Associates (2019), Stehly et al. (2018), JRC (2016)*

## CAPACITY FACTORS

The range of capacity factors for offshore wind farms is very wide due to differences in the meteorology among wind farm sites, the technology used and the configuration of the wind farm, *i.e.*, the optimal turbine spacing to minimise wake losses and increase energy yields. Optimisation of the O&M strategy over the life of the project is also an important determinant of the realised lifetime capacity factor.

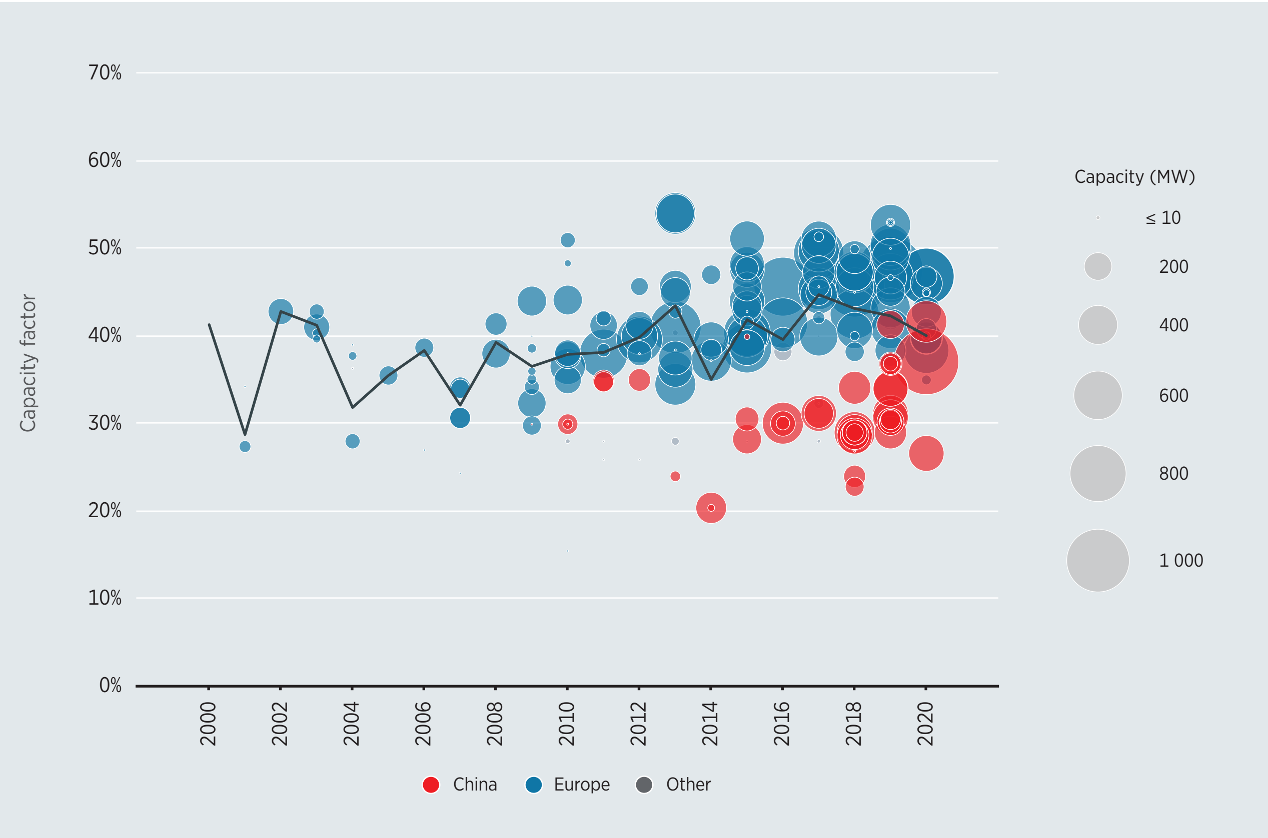
Between 2010 and 2020, the global weighted-average capacity factor of newly commissioned offshore wind farms grew from 38% to 40%. In 2020, the capacity factor range (5$^{th}$ and 95$^{th}$ percentile) for newly installed projects was between 33% and 47% (Figure 4.6). The decline in the global weighted-average capacity factor since 2017 has predominantly, but not entirely, been driven by the increased share of China in global deployment. As discussed, China's projects tend to be near shore or inter-tidal, resulting in poorer wind resources than those sited further offshore. In addition, China's projects do not use the very large, state-of-the-art turbines being deployed in Europe and elsewhere.

The weighted-average capacity factor for projects commissioned in Europe increased by 13% (or five percentage points) from 39% in 2010 to 44% in 2020. In Europe, the 5$^{th}$ and 95$^{th}$ percentile capacity factor for projects commissioned in 2020 was 37% and 47%, In contrast, the weighted-average capacity factor for projects commissioned in China in 2020 was 37%, while the 5$^{th}$ and 95$^{th}$ percentiles were 28% and 41%, respectively.

Capacity factors have been rising due to the installation of larger wind turbines with higher hub-heights and larger swept areas that harvest more electricity from the same resource than older machines. There has also been a contribution from reduced downtime as manufacturers have integrated experience from operating wind farm models into new, more reliable designs. It is also worth noting the experience in optimising O&M practices to reduce unscheduled maintenance that has been unlocked by improvements in data collection and analytics, allowing for predictive maintenance and production output optimisation. In addition, improvements in the development stage, due to greater experience, have led to better methods for wind resource characterisation when it comes to identifying the best sites, and improved wind farm designs that optimise operational output.

For the period 2010 to 2020, an examination of weighted-average capacity factor improvements in countries with offshore wind installations shows that the greatest improvement was in China, where there was a 23% increase over the period (Table 4.2). Germany was the exception to generally increasing capacity factors over the period. This can be attributed to the already relatively high capacity factor achieved in 2010, significantly above its peers, and the growing weight of projects that have been commissioned in the Baltic Sea, where lower average wind speeds than in the North Sea are the norm (Wehrmann, 2020).

**Figure 4.6** Project and weighted-average capacity factors for offshore wind, 2000-2020




*Source: IRENA Renewable Cost Database.*

**Table 4.2** Weighted-average capacity factors for offshore wind projects in six countries, 2010 and 2020

| | 2010 | 2020 | Percentage change 2010-2020 |
|---|---|---|---|
| | % | | |
| Belgium | 38 | 41 | ↑ 8% |
| China | 30 | 37 | ↑ 23% |
| Denmark* | 44 | 50 | ↑ 14% |
| Germany | 46 | 45 | ↓ 2% |
| Japan* | 28 | 30 | ↑ 7% |
| Netherlands** | 48** | 47 | ↓ 2% |
| United Kingdom | 36 | 38 | ↑ 6% |

*Source: IRENA Renewable Cost Database.*

* *Countries with data only for projects commissioned in 2019*

** *The Netherlands had no projects commissioned in 2010, so data for projects commissioned in 2015 are shown*

## OPERATION AND MAINTENANCE COSTS

O&M costs for offshore wind farms per kW are higher than those for onshore wind. This is mainly due higher costs for access to the wind site for performing maintenance on turbines and cabling. The latter is heavily influenced by weather conditions and the availability of skilled personnel and specialised vessels. However, given the higher capacity factors offshore, O&M costs are also amortised over a larger output, meaning offshore wind O&M costs typically constitute 16-25% of the LCOE for offshore wind farms deployed in the G20 (Group of Twenty) countries.

As with onshore wind, however, limited data are available for offshore wind O&M costs. There is also general uncertainty around lifetime O&M costs for offshore wind owing to limited operational experience, especially in sites farther offshore. As mentioned in the capacity factor discussion, O&M practices are being continuously refined to reduce costs and improve availability. As a result of improved capacity factors, and due to increased competition in O&M provision, O&M costs per kilowatt-hour (kWh) have been falling through time.

For 2018, representative ranges for current projects fell between USD 70/kW per year to USD 129/kW per year (IEA *et al.*, 2018; Ørsted, 2019; Stehly *et al.*, 2018). The lower range was observed for projects in established European markets and in China, usually with sites closer to shore. The range is broad because the O&M costs vary depending on local O&M optimisation and synergies from offshore wind farm zone clustering, as well as on the approach taken by the offshore wind farm owners after the initial turbine original equipment manufacturer (OEM) warranty period. As the sector has grown, increased competition in O&M provision has emerged and has resulted in a variety of strategies to minimise O&M costs (*e.g.,* the use of independent service providers, turbine OEMs' service arms, in-house O&M, marine contractors, or a combination thereof).

Besides the impact of experience and competition on O&M cost reduction, higher turbine ratings have reduced the unit O&M costs. An example of the O&M cost reduction impact from these factors comes from Ørsted – a major offshore wind developer with a portfolio of up to 9.9 GW of offshore wind farms in operation or under construction globally – who have been able to reduce O&M costs from 2015 to 2018 by over 43%, from USD 118/kW/year to USD 67/kW/year (Ørsted, 2019).

IRENA analysis shows that, based on commissioned projects over the last 5 years, O&M costs account for USD 0.017/kWh to USD 0.030/kWh[2], with the lower cost range observed in established markets in Europe and China and the higher cost ranges in less-established markets where O&M supply chains have not been fully established, *e.g.,* South Korea (which also has lower weighted-average capacity factors).

### Levelised cost of electricity

In recent years, increasing experience and competition, advances in wind turbine technology, the establishment of optimised local and regional supply chains, and strong policy and regulatory support have resulted in a steady pipeline of projects that have been increasingly competitive.

Between 2010 and 2020, the global weighted-average LCOE of offshore wind fell 48%, from USD 0.162/kWh to USD 0.084/kWh (Figure 4.6). Year-on-year, in 2020, weighted-average LCOE fell 9% from its 2019 value of USD 0.093/kWh. From its peak in 2007, the global weighted-average LCOE of offshore wind fell by 53%.

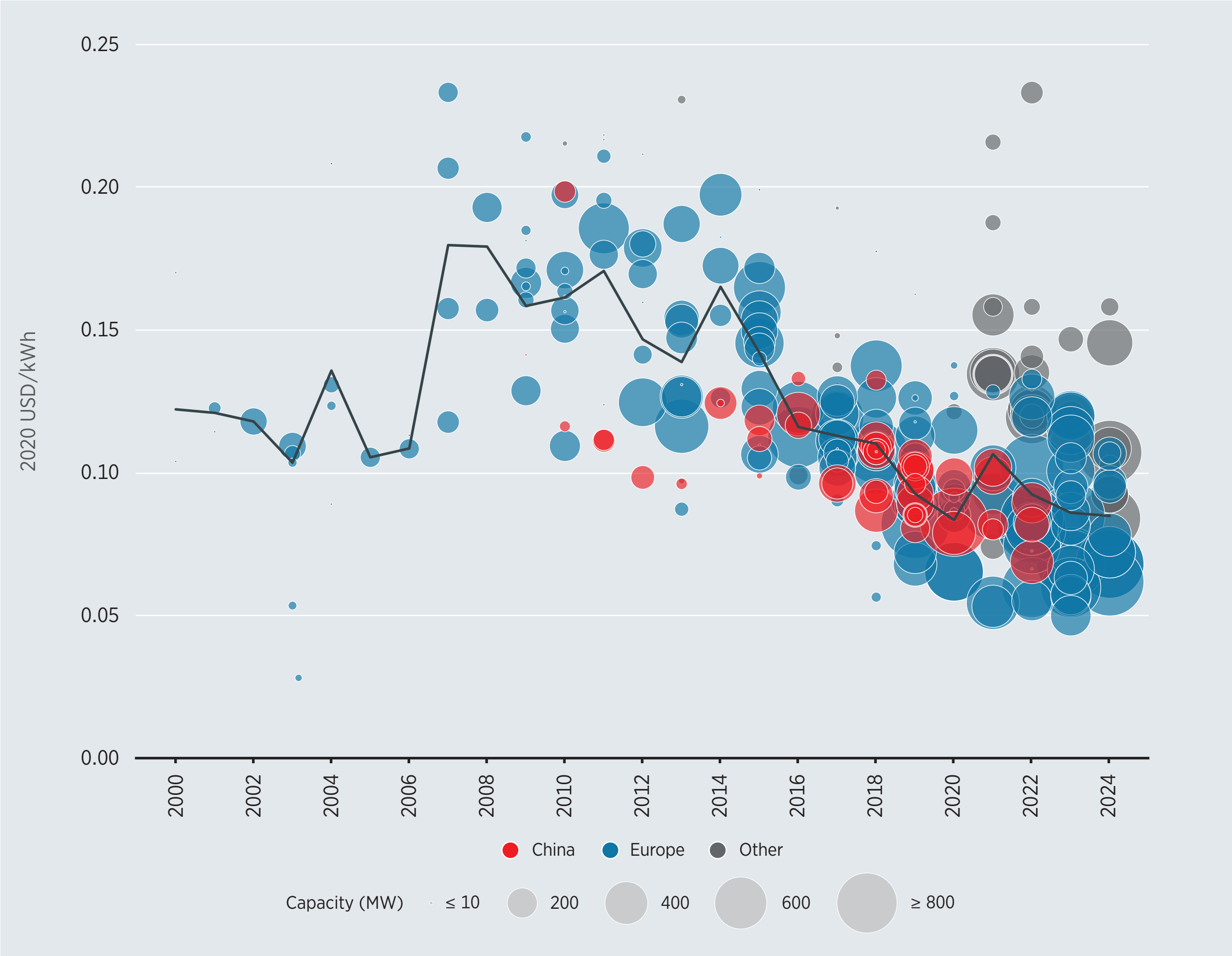
*Between 2010 and 2020, the global weighted-average LCOE for offshore wind fell 48%*

The Netherlands had the lowest weighted-average LCOE for projects commissioned in 2020, at USD 0.067/kWh (Table 4.3). China had the second-lowest weighted-average LCOE, at USD 0.084, and it also had the second-highest percentage reduction in country weighted-average LCOE values between 2010 and 2020, at 52%. Belgium and Denmark had close weighted-average LCOE values in 2020. Belgium saw the highest percentage reduction (56%) in country weighted-average LCOE values between 2010 and 2020, with the highest starting point in 2010, at USD 0.198/kWh. Meanwhile, Denmark had a reduction of 20% between 2010 and 2020. Denmark was the first country to pioneer offshore wind at a commercial scale, with the commissioning of the Vindeby wind project in 1991. Denmark's low LCOE is driven by experience, projects that are located close to shore and in shallower waters than many of its neighbours, and the fact that wind farm-to-shore transmission assets are not the responsibility of the project developer.

As Figure 4.7 shows, the recent auction and power purchase agreement (PPA) results for projects expected to be commissioned in the period up to 2024 represent a step change in competitiveness, with prices falling into the USD 0.050/kWh to USD 0.10/kWh range.

2 *This excludes Japan, where deployment has not yet reached commercial-scale and the O&M costs are not representative of commercial projects.*

**Figure 4.7** Offshore wind project and global weighted-average LCOEs and auction/PPA prices, 2000-2024




*Source: IRENA Renewable Cost Database.*

**Table 4.3** Regional and country weighted-average LCOE of offshore wind, 2010 and 2020

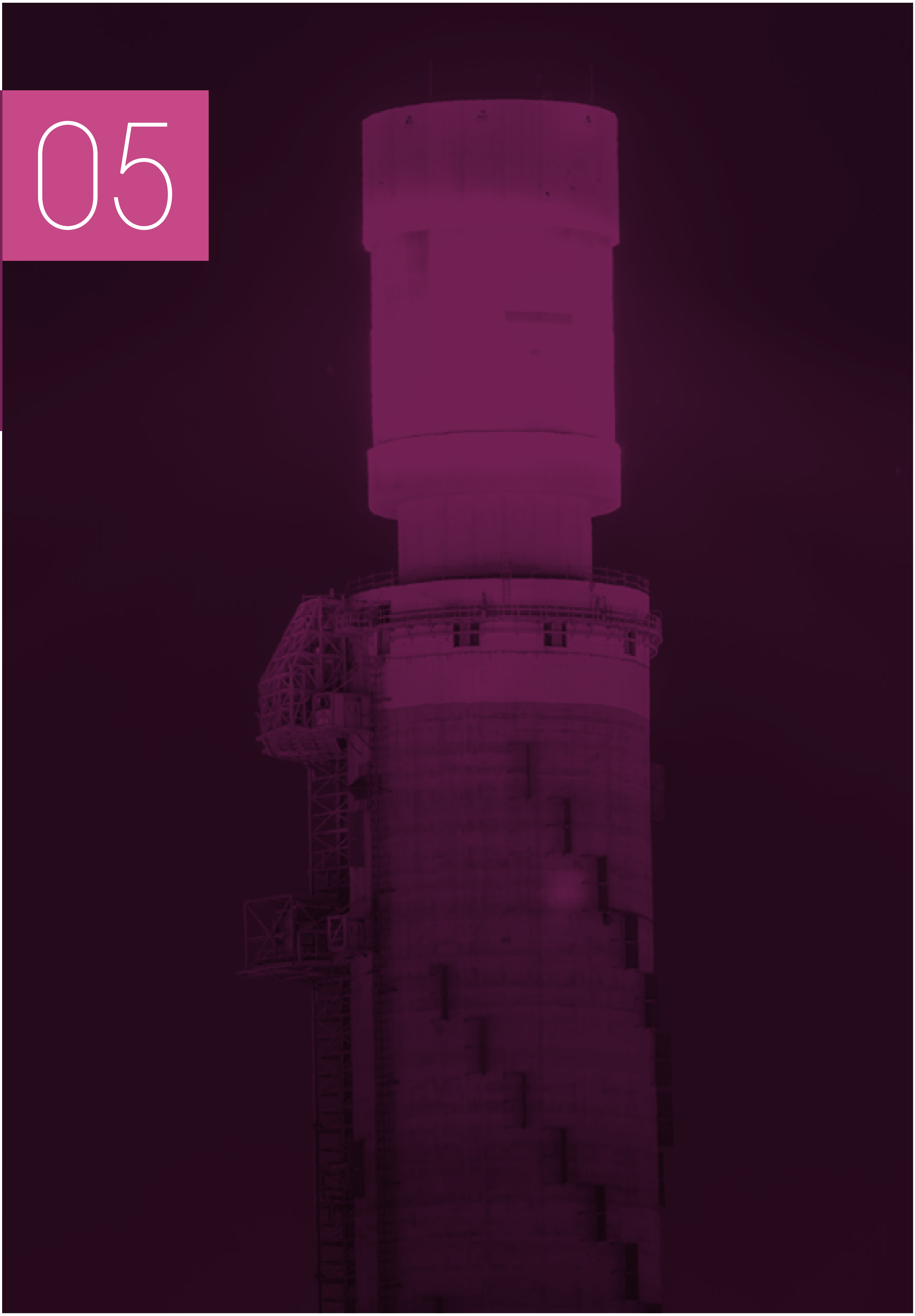
| | 2010 | | | 2020 | | |
|---|---|---|---|---|---|---|
| | 5th percentile | Weighted average | 95th percentile | 5th percentile | Weighted average | 95th percentile |
| | (2020 USD/kW) | | | | | |
| **Asia** | 0.123 | **0.181** | 0.213 | 0.080 | **0.085** | 0.118 |
| China | 0.121 | **0.178** | 0.195 | 0.080 | **0.084** | 0.097 |
| Japan* | 0.215 | **0.215** | 0.215 | 0.200 | **0.200** | 0.200 |
| Republic of Korea | n.a. | **n.a.** | n.a. | 0.122 | **0.122** | 0.122 |
| **Europe** | 0.124 | **0.158** | 0.288 | 0.066 | **0.083** | 0.131 |
| Belgium | 0.198 | **0.198** | 0.198 | 0.085 | **0.087** | 0.090 |
| Denmark* | 0.110 | **0.110** | 0.110 | 0.088 | **0.088** | 0.088 |
| Germany | 0.164 | **0.166** | 0.171 | 0.088 | **0.093** | 0.095 |
| Netherlands | n.a. | **n.a.** | n.a. | 0.066 | **0.067** | 0.131 |
| United Kingdom | 0.151 | **0.162** | 0.170 | 0.115 | **0.115** | 0.115 |

*Source: IRENA Renewable Cost Database*

** = Countries with data only for projects commissioned in 2019*


REN

# 05

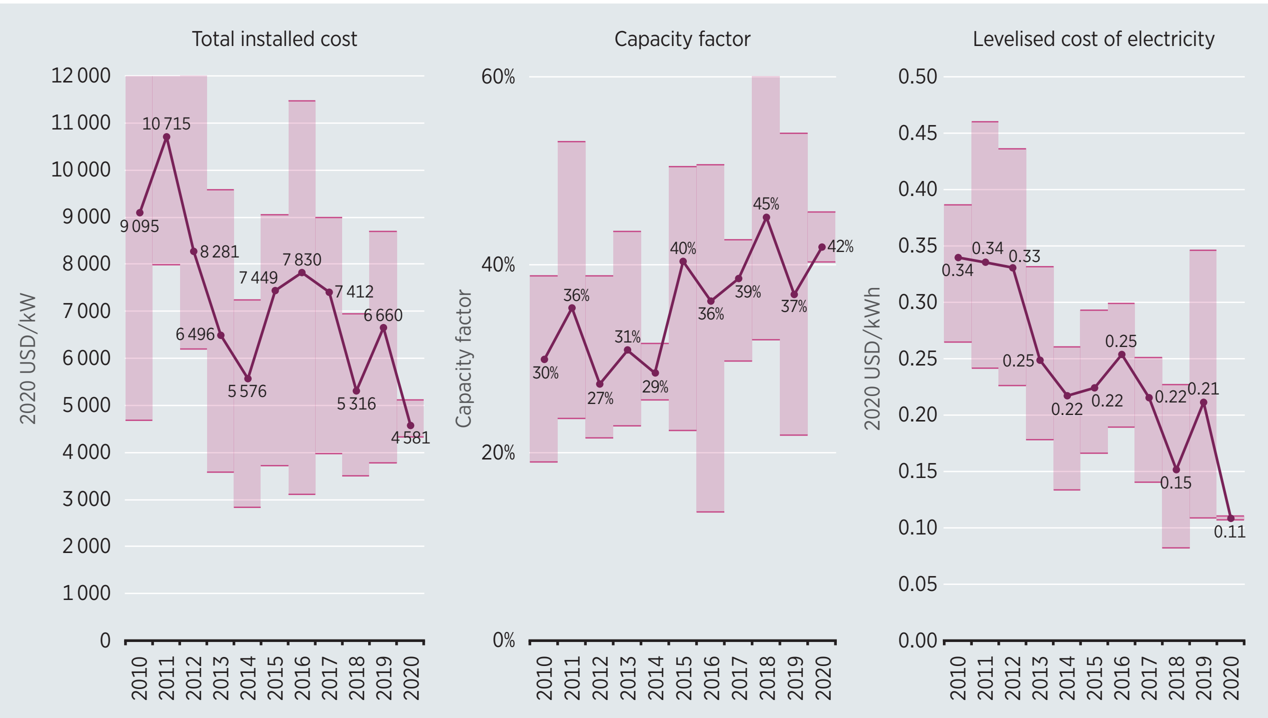


# CONCENTRATING SOLAR POWER

## HIGHLIGHTS

- The weighted average LCOE of CSP plants fell by 68% between 2010 and 2020, from USD 0.34/kWh to USD 0.108/kWh.
- In 2020, 150 MW of new CSP was installed and the global weighted average total installed costs of these CSP plants was USD 4 581/kW. This was 31% lower than in 2019 – when a number of delayed projects were completed – and 50% lower than in 2010.
- In 2018 and 2019, the cost range of projects with 8 hours or more of thermal storage was between USD 4 126/kW and USD 5 945/kW. Between 2018 and 2020, three projects in China were commissioned with more than 10 hours of storage, with a total installed cost range of USD 4 126 to USD 5 154/kW.
- The capacity factor of CSP plants increased from 30% in 2010 to 42% in 2020, as the technology improved, costs for thermal energy storage declined and the average number of hours of storage for commissioned projects increased.
- The global weighted-average LCOE declined by around USD 0.24/kWh between 2010 and 2020. This was primarily driven by reductions in total installed costs (47%), higher capacity factors (28%), the assumed reduction in the weighted-average cost of capital (20%), and lower O&M costs (4%).
- Data in the IRENA Auction and PPA Database shows a weighted-average price of electricity of around USD 0.076/kWh for CSP projects to be commissioned in 2021.

**Figure 5.1** Global weighted-average total installed costs, capacity factors and LCOE for CSP, 2010-2020




*Source: IRENA Renewable Cost Database.*

Concentrating solar power (CSP) systems work in areas with high direct normal irradiance (DNI) by concentrating the sun's rays using mirrors to create heat. In most systems today, the heat created from concentrating the sun's energy is transferred to a heat transfer medium, typically a thermal oil or molten salt. Electricity is then generated through a thermodynamic cycle, for example using the heat transfer fluid to create steam and then generate electricity, as in conventional Rankine-cycle thermal power plants.

CSP plants today almost exclusively include low-cost thermal storage systems to decouple generation from the sun. Indeed, this is also usually the route to lowest-cost and highest value electricity. Most commonly, a two-tank, molten salt storage system is used, but designs vary.

It is possible to classify CSP systems according to the mechanism by which solar collectors concentrate solar irradiation, either 'line concentrating' or 'point concentrating' varieties. These terms refer to the arrangement of the concentrating mirrors. Today, most existing systems use linear concentrating systems called parabolic trough collectors (PTCs). Typically, single PTCs consist of a holding structure with individual line focusing curved mirrors, a heat receiver tube and a foundation with pylons. The collectors concentrate the solar radiation along the heat receiver tube (also known as absorber), a thermally efficient component placed in the collector's focal line. Various PTCs are traditionally connected in 'loops' through which the heat transfer medium circulates to achieve scale.

Line concentrating systems rely on single-axis trackers to maintain energy absorption across the day increasing the yield by generating favourable incidence angles of the of the sun's rays on the aperture area of the collector. Specific PTC configurations must account for the solar resources at the location and the technical characteristics of the concentrators and heat transfer fluid. That fluid is passed through a heat exchange system to produce superheated steam, which drives a conventional Rankine-cycle turbine to generate electricity.

Another type of linear-focusing CSP plant, though much less deployed, uses Fresnel collectors. This type of plant relies on an array of almost flat mirrors that concentrate the sun's rays onto an elevated linear receiver above the mirror array. Unlike parabolic trough systems, in Fresnel collector systems, the receivers are not attached to the collectors, but situated in a fixed position several metres above the primary mirror field.

Solar towers (STs), sometimes also known as 'power towers', are the most widely deployed point focus CSP technology, but represented only around a fifth of the systems deployed at the end of 2020 (SolarPACES, 2021). In solar tower systems, the collectors are called heliostats (a ground-based array of mirrors) and thousands are arranged in a circular or semi-circular pattern around a large central receiver tower. Each heliostat is individually controlled to track the sun, orientating constantly on two axes to optimise the concentration of solar irradiation onto the receiver, which is located at the top of a tower. The central receiver absorbs the heat through a heat transfer medium, which turns it into electricity – typically through a water-steam thermodynamic cycle. Some solar tower designs do away with the heat transfer medium and steam is directly generated at the receiver.

Solar towers achieve very high solar concentration factors (above 1000 suns) and therefore operate at higher temperatures than PTCs. This can give solar tower systems an advantage, as higher operating temperatures result in greater steam-cycle generating efficiency. Higher receiver temperatures unlock higher power block efficiencies and also result in greater storage densities within the molten salt tanks, driven by a larger temperature difference between the cold and hot storage tanks. Both factors cut generation costs and allow for higher capacity factors.

Cumulative CSP installed capacity grew just over five-fold, globally, between 2010 and 2020, reaching around 6.5 GW at the end of 2020. After modest activity in 2016 and 2017 – with annual additions hovering around 100 MW per year – the global market for CSP grew in 2018 and 2019. In those years, an increasing number of projects came online in China, Morocco and South Africa. Yet compared to other renewable power generation technologies, new capacity additions overall remained relatively low, at 860 MW per year in 2018 and 550 MW in 2019. Unfortunately, only 150 MW was commissioned in 2020 globally, with all of this coming online in China.

The sector was optimistic that China's plans to scale up the technology domestically would provide a boost to the industry and take deployment to new levels. Yet, progress on China's policy to build-out 20 commercial-scale plants to scale up a variety of technological solutions, develop supply chains and gain operating experience has proved more challenging than anticipated. A number of developers were able to meet the required commissioning dates, but – for a variety of reasons – many have struggled and some projects have been lagging, while others have found new developers. Meanwhile, others appear unlikely to be completed.

The outlook for 2021 is somewhat brighter, however, with the possibility that close to 1 GW of new capacity could be commissioned in Chile, China and the United Arab Emirates. The pipeline after that looks sparse, though, and greater policy support for this clean, 24/7 power supply is merited.

## TOTAL INSTALLED COSTS

In the early years of CSP plant development, adding thermal energy storage was often uneconomic and generally unwarranted so its use was limited. Since 2015, however, hardly any projects have been built or planned without thermal energy storage, as adding this is now a cost-effective way to raise capacity factors, while it also contributes to a lower LCOE and greater flexibility in dispatch, over the day.

The average thermal storage capacity for PTC plants in the IRENA Renewable Cost Database increased from 3.3 hours between 2010 and 2014 to 5.7 hours between 2015 and 2019 (an increase of almost three-quarters). For STs, that value increased from 5 hours in the 2010-2014 period to 7.7 hours in the 2015-2019 period (a 54% increase). In 2020, the 150 MW of newly commissioned capacity in China had a weighted-average storage capacity of 11.7 hours. Inaugurated in 2021, the Cerro Dominador 110 MW solar tower project located in Chile's Atacama Desert, features a storage capacity of 17.5 hours.

Total installed costs for both PTC and ST plants are dominated by the cost of the components that make up the solar field. This is particularly true for PTC plants, where they account for 39% of the total installed costs (Table 5.1). In ST plants, the share of the solar field components is a lower percentage, at around 28%, with significant shares of costs for the receiver (18%) and power block (16%).

Total installed costs for CSP plants fell by one half (50%) between 2010 and 2020. This has occurred even as the size of these projects' thermal energy storage systems has increased. During 2018 and 2019, the installed costs of CSP plants with storage were at par or lower than the capital costs of plants without storage commissioned in the 2010-2014 period – sometimes dramatically so. The projects commissioned in 2018 and 2019 contained in the IRENA Renewable Cost Database had an average of 7.2 hours

**Table 5.1** Representative CSP total installed costs by component, 2020

| | Parabolic trough | Solar Tower |
|---|---|---|
| **Owner's cost** | 8% | 9% |
| **Indirect EPC cost** | 12% | 15% |
| **Thermal storage** | 17% | 12% |
| **Power block** | 18% | 16% |
| **Tower** | 0% | 2% |
| **Receiver** | 6% | 18% |
| **Solar field** | 39% | 28% |

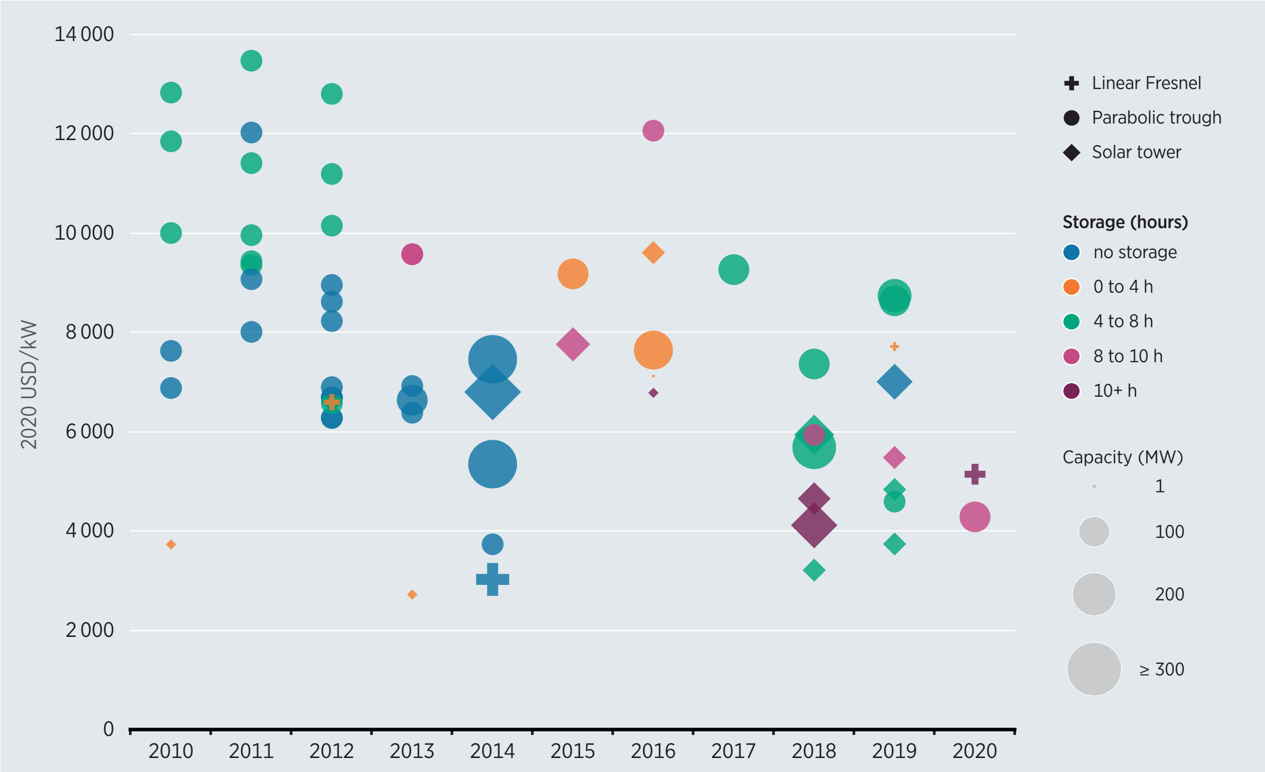
*Source: IRENA Renewable Cost Database.*

of storage. This is 2.2 times larger than the average value for projects commissioned between 2010 and 2014 and is continuing to grow. For instance, the weighted-average storage level for projects commissioned in 2020 was 11.7 hours, which is 63% higher than those of 2018-2019 (SolarPACES, 2021).

The capital costs for CSP projects commissioned in 2020 for which cost data is available in the IRENA Renewable Cost Database ranged between USD 4 295/kW and USD 5 154/kW (Figure 5.2).

With only two projects completed in China in 2020, with a total of 150 MW, the data reflects the national circumstances, much as Spain did in the years 2010 to 2012, inclusive. The two projects completed in China are part of 20 pilot projects that were designed to test a range of technology concepts and gain experience in integrating a wide range of technologies and plant configurations in the electricity system. This pilot programme, launched in 2016 and aiming to develop 1.35 GW of capacity, initially targeted completion by 2018,

**Figure 5.2** CSP total installed costs by project size, collector type and amount of storage, 2010-2020




*Source: IRENA Renewable Cost Database.*

*Note: Only projects in the database with information available for all the variables displayed are shown. Data can therefore diverge from the global dataset.*

but undoubtedly this timeline was too ambitious. With weighted average total installed costs of USD 4 639/kW in 2020, costs were 30% lower than the weighted average of USD 6 660/kW for projects commissioned in 2019, or 20% lower, if the two much-delayed Israeli projects commissioned in 2019 are excluded.

During 2018 and 2019, IRENA's Renewable Cost Database shows a capital cost range of between USD 3 221/kW and USD 8 748/kW for CSP projects with storage capacities of between 4 and 8 hours. In the same period, the cost range for projects with 8 hours or more of thermal storage capacities was narrower – between USD 4 126/kW and USD 5 945/kW – and had a lower maximum value. This was due to the fact these projects were in China. Between 2018 and 2020, three projects in China have been commissioned with greater than 10 hours of storage, with a total installed cost range from USD 4 126/kW to USD 5 154/kW.

*Total installed costs for CSP plants fell by 50% between 2010 and 2020. This has occurred even as the size of these projects' thermal energy storage systems has increased.*

## CAPACITY FACTORS

As with all solar and wind technologies, the capacity factor of a specific project is determined by the quality of the resources, the technology used and the desired operating conditions. For CSP, the quality of the solar resource, along with the technology configuration, are the determining factors in the achievable capacity factor at a given location and technology. CSP is somewhat unique in that the potential to incorporate low-cost thermal energy storage can increase the capacity factor – up to a certain level, given that there are diminishing marginal returns – and reduce the LCOE.

This is, however, a complex design optimisation that is driven by the desire to minimise the LCOE and/or meet the operational requirements – either of grid operators or shareholders – in capturing the highest wholesale price.

This optimisation of a CSP plants design requires detailed simulations, taking into account the site's solar resource, the project's storage capacity and the necessary solar field size to minimise LCOE and ensure optimal utilisation of the heat generated. This is a delicate balance, as smaller than optimal solar field sizes result in under-utilisation of the thermal energy storage system and the selected power block. A larger than optimal solar field size, however, would add additional capital costs, but increase the capacity factor – albeit at the potential risk of heat generation being curtailed at times, due to lack of storage and/or power generation capacity.

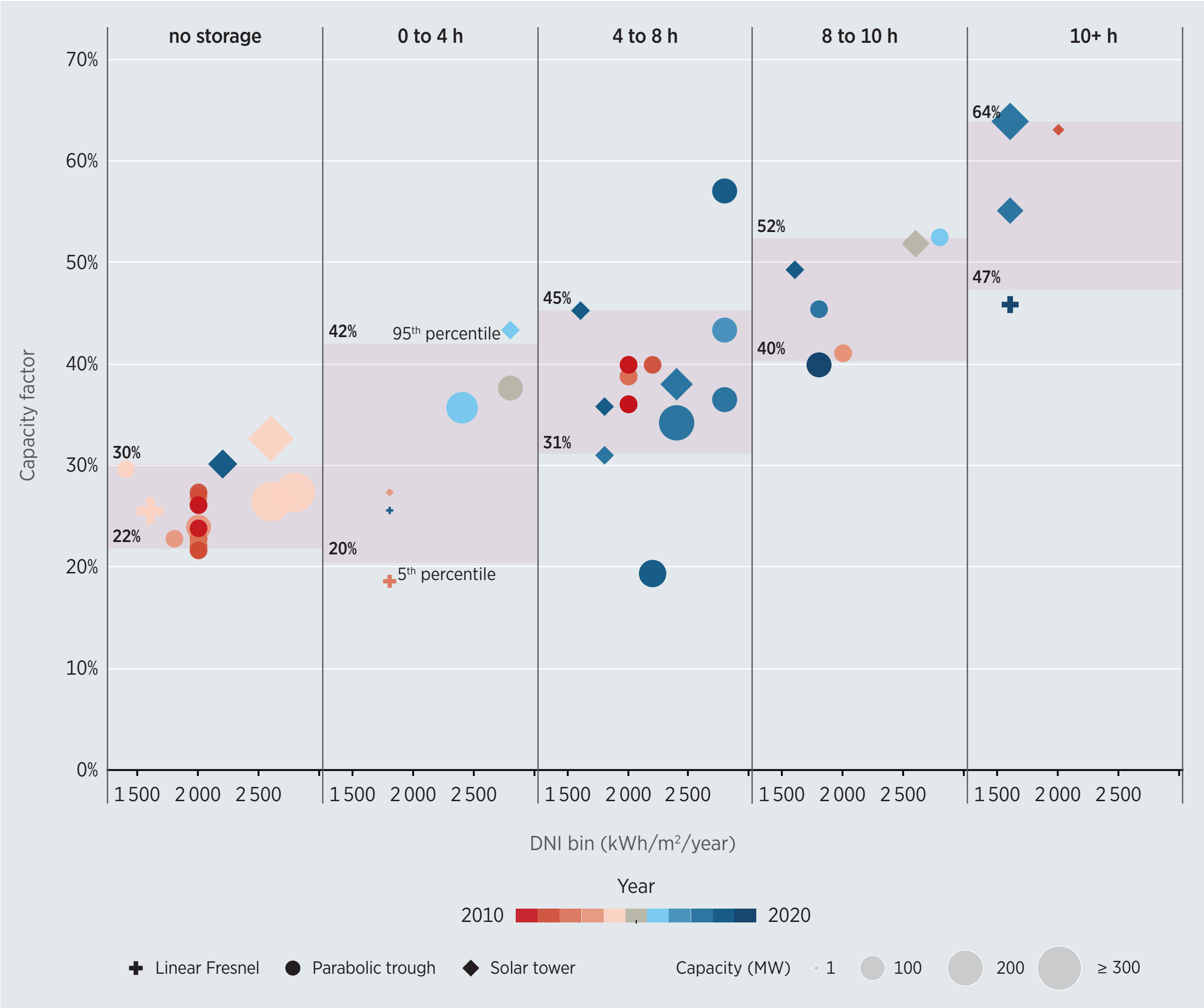
*The global weighted-average capacity factor of newly commissioned plants increased from 30% in 2010 to 42% in 2020 – an increase of 41% over the decade*

Over the last decade, falling costs for thermal energy storage and increased operating temperatures have been important developments that have improved CSP economics. Indeed, the increased operating temperatures also lower the cost of storage, as higher heat transfer fluid (HTF) temperatures lower storage costs. For a given DNI level and plant configuration conditions, higher HTF temperatures allow for a larger temperature differential between the 'hot' and 'cold' storage tanks. This means greater energy (and hence storage duration) can be extracted for a given physical storage size, or less storage medium volume is needed to achieve a given number of storage hours. Combined, since 2010, these factors have increased the optimal level of storage at a given location, helping minimise LCOE.

These drivers have contributed to the global weighted-average capacity factor of newly commissioned plants rising from 30% in 2010 to 42% in 2020 – an increase of 41% over the decade. The 5$^{th}$ and 95$^{th}$ percentiles of the capacity factor values for projects in IRENA's Renewable Cost Database commissioned in 2019 were 22% and 54% respectively. In 2020, the range for both projects was from 40% to 46%.

The increasing capacity factors for CSP plants driven by increased storage capacity can clearly be seen in Figure 5.3. Over time, CSP projects have been commissioned with longer storage durations. For plants commissioned between 2016 and 2020, inclusive, around four-fifths of all projects have had at least four hours of storage and 35% have had 8 hours or more. The impact of the economics of higher energy storage levels is evident in that in 2020, newly commissioned plants had a weighted-average capacity factor of 42%, with and average DNI that was lower than for plants commissioned between 2010 and 2013, inclusive – a period when the weighted-average capacity factor was between 27% and 35% for newly commissioned plants.

**Figure 5.3** Capacity factor trends for CSP plants by direct normal irradiance and storage duration, 2010-2020




*Source: IRENA Renewable Cost Database and CSP Guru, 2020, for DNI values.*

## OPERATIONS AND MAINTENANCE COSTS

For CSP plants, all-in O&M costs, which include insurance and other asset management costs, are substantial compared to solar PV and onshore wind. They also vary from location to location, depending on differences in irradiation, plant design, technology, labour costs and individual market component pricing, linked to local cost differences.

Historically, the largest individual O&M cost for CSP plants has been expenditure on receiver and mirror replacements. As the market has matured, experience, as well as new designs and improved technology, have helped reduce failure rates for receivers and mirrors, however, driving down these costs. Personnel costs represent a significant component of O&M, with the mechanical and electrical complexity of CSP plants relative to solar PV, in particular, driving this. Insurance charges continue to be an important contributor to O&M costs, though, and typically range between 0.5% and 1% of the initial capital outlay (a figure that is lower than the total installed cost).

With some exceptions, typical O&M costs for early CSP plants still in operation today range from USD 0.02/kWh to USD 0.04/kWh. This is likely a good approximation for the current levels of O&M in relevant markets for projects built in and around 2010, globally, even if based on an analysis relying on a mix of bottom-up engineering estimates and best-available reported project data (Fichtner, 2010; IRENA, 2018; Li *et al.*, 2015; Turchi,2017; Turchi *et al.,* 2010; Zhou, Xu and Wang, 2019).

In collaboration with DLR, analysis by IRENA, however, shows that more competitive O&M costs are possible in a range of markets (Table 5.2) where projects achieved financial closure in 2019 and 2020. The O&M costs in many markets are high in absolute terms, compared to solar PV and many onshore wind farms, per kWh, but are about 18-20% of the LCOE for projects in G20 countries. Taking this into account, for the LCOE calculations in the following section, O&M costs declined from an average of USD 0.03/kWh in 2010 to USD 0.02/kWh in 2020.

**Table 5.2** All-in (insurance included) O&M cost estimates for CSP plants in selected markets, 2019-2020

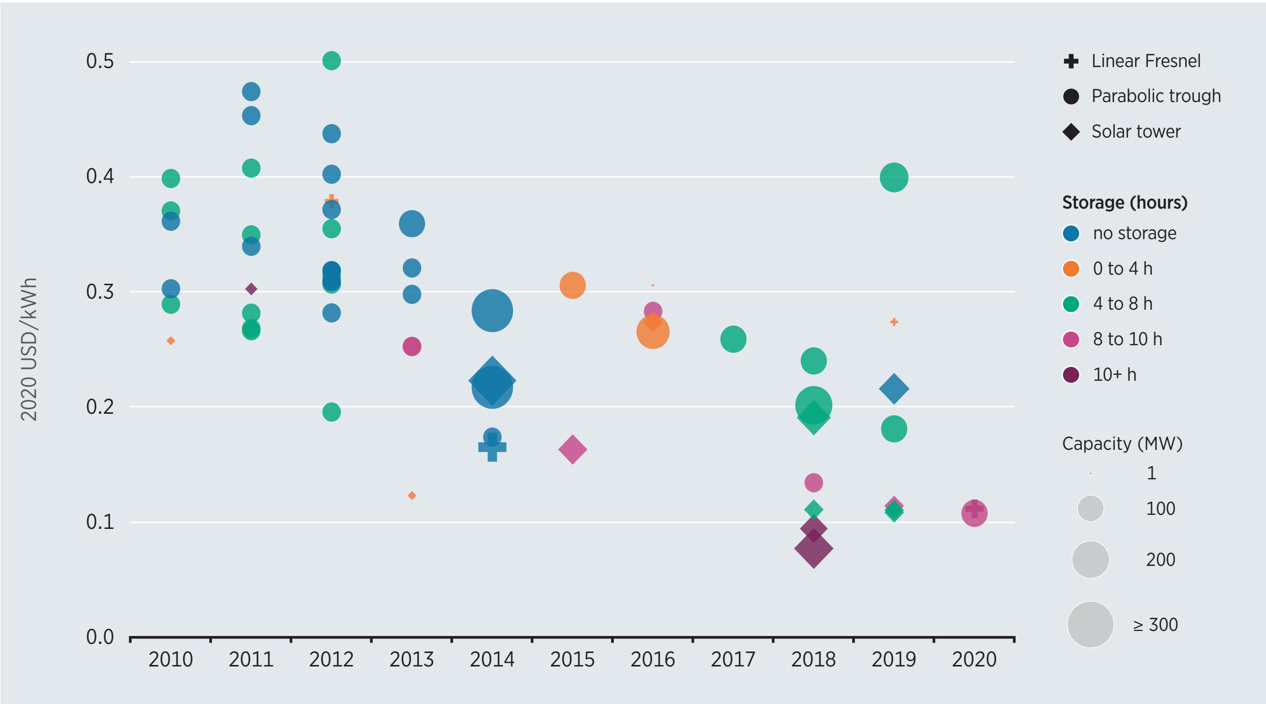
| Country | Parabolic trough collectors (2020 USD/kWh) | Solar tower (2020 USD/kWh) |
|---|---|---|
| **Argentina** | 0.025 | 0.023 |
| **Australia** | 0.027 | 0.026 |
| **Brazil** | 0.020 | 0.020 |
| **China** | 0.021 | 0.018 |
| **France** | 0.032 | 0.027 |
| **India** | 0.015 | 0.015 |
| **Italy** | 0.025 | 0.023 |
| **Mexico** | 0.016 | 0.015 |
| **Morocco** | 0.013 | 0.012 |
| **Russian Federation** | 0.024 | 0.022 |
| **Saudi Arabia** | 0.012 | 0.011 |
| **South Africa** | 0.013 | 0.012 |
| **Spain** | 0.024 | 0.022 |
| **Turkey** | 0.018 | 0.016 |
| **United Arab Emirates** | 0.018 | 0.020 |
| **United States of America** | 0.024 | 0.021 |

*Source: IRENA Renewable Cost Database.*

## LEVELISED COST OF ELECTRICITY

With the reduction in total installed costs and O&M costs, increasing capacity factors and falling financing costs, the LCOE for CSP fell significantly between 2010 and 2020. Over that period, the global weighted-average LCOE of newly commissioned CSP plants fell by 68%, from USD 0.34/kWh in 2010 to USD 0.108/kWh (Figure 5.4). This was due to: a 50% reduction in the global weighted-average total installed costs of newly commissioned CSP plants; an increase in capacity factors from 30% to 42% (a 41% increase); a decline in O&M costs by a third; and the assumed reduction in the weighted-average cost of capital (WACC).

**Figure 5.4** The LCOE for CSP projects by technology and storage duration, 2010-2020




*Source: IRENA Renewable Cost Database.*

With deployment during the period 2010 to 2012 inclusive being dominated by Spain – and mostly comprised of PTC plant – the global weighted-average LCOE by project declined only slightly, albeit within a widening range, as new projects came online. This changed in 2013, when a clear downward trend in the LCOE of projects emerged as the market broadened, experience was gained and more competitive procurement started to have an impact. Rather than technology-learning effects alone driving lower project LCOEs from 2013 onward, the shift in deployment to areas with higher DNIs during the period 2013 to 2015 also played a role (Lilliestam *et al.*, 2017). In the period 2016 to 2019, costs continued to fall and the commissioning of projects in China became evident, with projects commissioned there in 2018 and beyond achieving estimated LCOEs of between USD 0.08/kWh and USD 0.13/kWh. At the same time, projects commissioned in 2018 and 2019 in Morocco and South Africa tended to have higher costs than this.

The commissioning of projects in locations with higher DNIs was a major contributor to the increased capacity factors (and therefore lower LCOE values) seen for projects commissioned between 2014 and 2017. The weighted average DNI of projects commissioned during the period 2014 to 2017, at around 2 600 kWh/$m^2$/year, was 28% higher than in the period 2010 to 2013. As already noted, however, this was not the only driver, as technological improvements saw a trend towards plant configurations with higher storage capacities. CSP with low-cost thermal energy storage has shown it can play an important role in integrating higher shares of variable renewables in areas with good DNI.

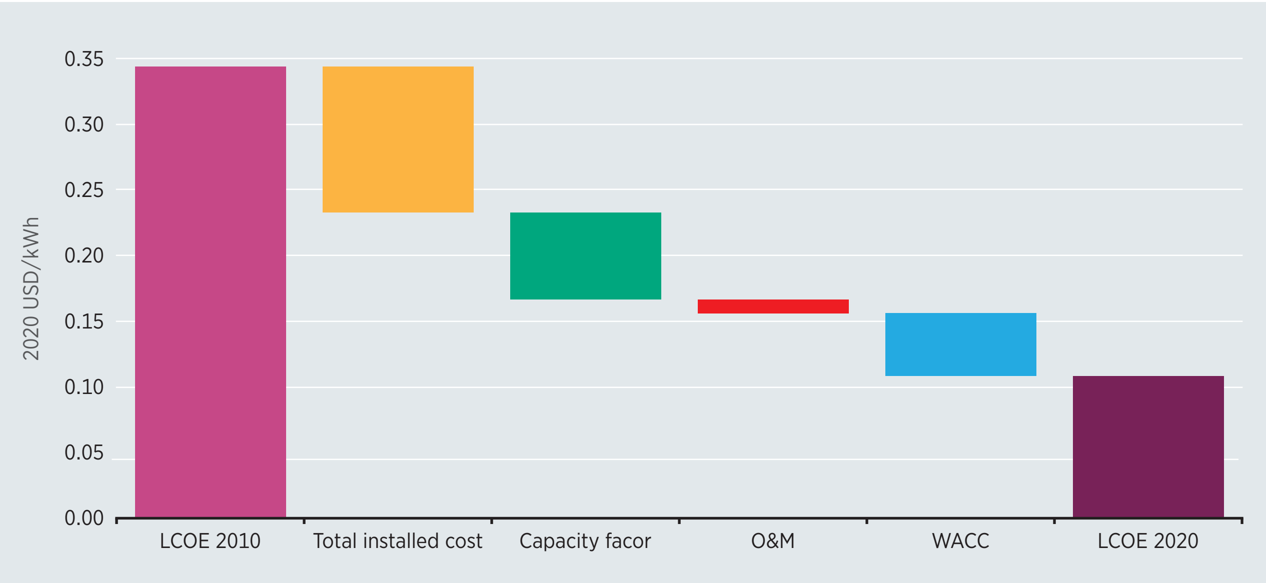
In 2016 and 2017, only a handful of plants were completed, with around 100 MW added in each year. The results for these two years are therefore volatile and driven by specific plant costs. The increase in LCOE in 2016 was driven by the higher costs of the early projects in South Africa and Morocco commissioned in that year. In 2017, the global weighted-average LCOE fell back to the level set in 2014 and 2015. New capacity additions then rebounded in 2018 and 2019, with an average of around 600 MW added each year. In 2018, plants were commissioned in China, Morocco and South Africa, with LCOEs ranging from a low of USD 0.077/kWh in China, to a high of USD 0.238/kWh in South Africa. In contrast, 2019 saw higher LCOEs, as two delayed Israeli projects came online, with costs ranging from USD 0.11/kWh for a project in China to USD 0.395/kWh for the Israeli PTC project.

Figure 5.5 decomposes[1] the 68% decline in the global weighted-average LCOE of CSP over the period 2010 to 2020 into its main constituents. The largest share of the reduction (47%) was due to the decline in the total installed cost of CSP plants over the period. Improvements in technology and cost reductions in thermal energy storage – which led to projects with longer storage duration being commissioned in 2020 – led to an improvement in capacity factors. This, in turn, accounted for 28% of the reduction in LCOE over the 2010-2020 period. The assumed reduction in the weighted-average cost of capital accounted for 20% of the total decline in LCOE during that time, while lower O&M costs accounted for the remainder (4%).

The IRENA Auction and PPA Database includes data for a number of plants that will be commissioned in 2021. The weighted-average price of electricity of these plants is around USD 0.076/kWh. This represents a reduction of around 30% compared to the global weighted-average LCOE seen in 2020.

These figures should be interpreted with care, however, since they are not directly comparable with the LCOE metric discussed here. Yet, these announcements do point towards the increased competitiveness of CSP projects, compared to fossil fuel alternatives. In the absence of strong policy support for CSP, however, the market remains small and the pipeline for new projects meagre. This is disappointing, given the remarkable success in reducing costs since 2010, despite just 6 GW being deployed globally at the end of 2020. Given the growth in variable renewables competitiveness since 2010, the value of CSP's ability to provide dispatchable power 24/7 in areas with high DNI at reasonable cost is only set to grow. Greater policy support would be instrumental in achieving even lower costs and reducing overall electricity system costs by providing firm, renewable capacity and flexibility services to integrate very high shares of renewables.

**Figure 5.5** Decomposition of the reduction in LCOE for CSP projects by source, 2010-2020




*Source: IRENA Renewable Cost Database.*

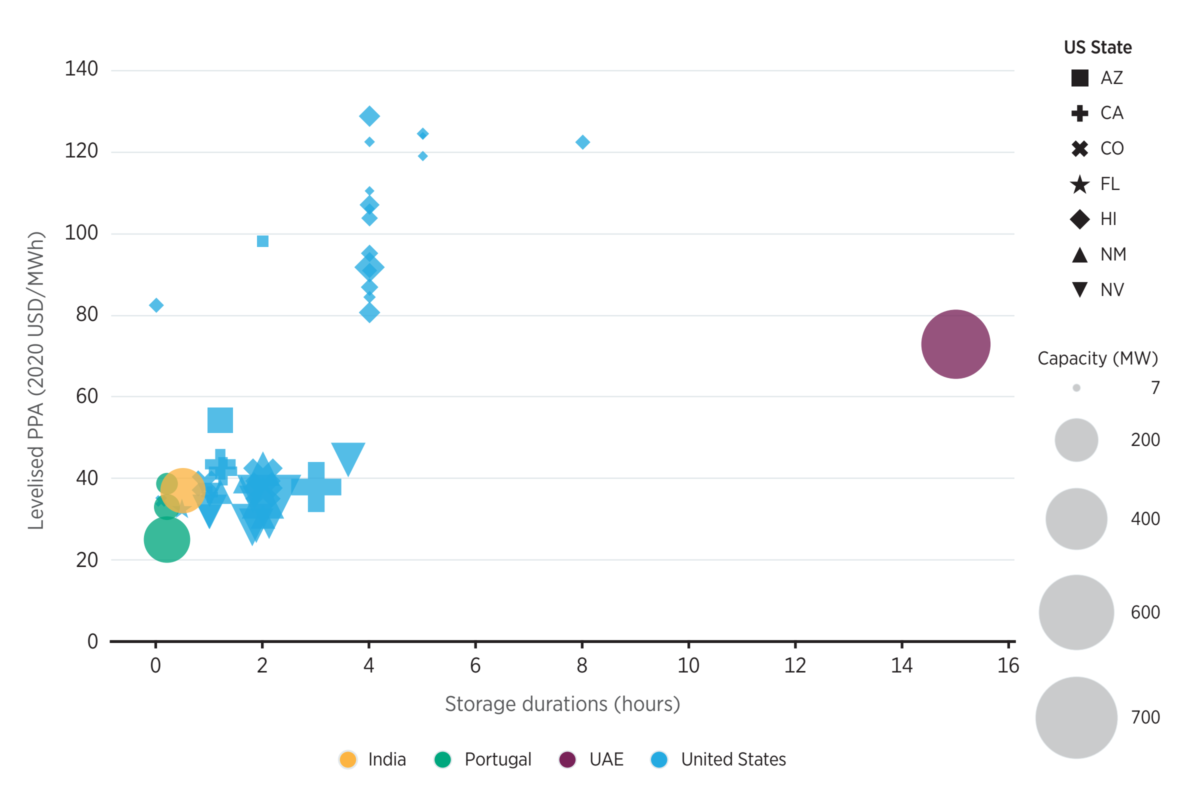
*1 This relies on a simple decomposition analysis that changes one variable – while holding all others constant – and then apportions these values as a share of the actual total reduction in LCOE over the period. The results are indicative and should be treated with caution.*

## Box 5.1 CSP and battery storage: Duration and costs matter

As highlighted in previous IRENA analysis, as costs for battery electricity storage systems fall, new market applications will become economic (IRENA, 2017a). Although battery storage often grabs the headlines, given its rapid cost reductions, CSP and its low-cost thermal storage systems are often overlooked. This is unfortunate, as CSP remains, along with pumped hydro storage, the only low-cost long-duration storage option available today. As the share of variable renewables grows, the possibility of adding low-cost long-duration storage will only grow in value.

The rapid cost declines for battery storage are rightly lauded, as their importance to the energy transition extends beyond the electricity sector. However, as Figure B5.1 illustrates, battery storage systems have practical limitations in terms of the storage duration they can economically provide. Figure B5.1 presents the levelised PPA prices[2] for a range of solar PV projects combined with storage in India, Portugal and the United States, as well as the PPA price for the 700 MW CSP project at the Mohammed bin Rashid Al Maktoum Solar Park in Dubai, United Arab Emirates.

**Figure B5.1** Results of recent auction and PPA results for utility scale solar PV and CSP




*Source: Based on LBNL, 2020; RenewPower, 2020; and Antuoko, 2020*

*Note: AZ = Arizona, CA = California, CO = Colorado, FL = Florida, HI = Hawaii, NM = New Mexico and NV = Nevada. The Indian project is predominantly an onshore wind project (80% onshore wind) with substantial solar PV capacity (20%) (Renew Power 2020). All but five of the solar PV projects in Figure B5.1 had PPA signing dates from 2018 to 2020, inclusive.*

2 *The PPA prices have been 'levelised' in that they reflect more closely LCOE values. For instance, the impact of the Investment Tax Credit in the United States has been removed, while nominal Indian PPA prices have been deflated to account for inflation and Portuguese projects' lifetime revenues have been estimated. The latter were effectively bidding for grid access, rather than for the sale of electricity. Storage duration has also been normalised to the alternating current (AC) capacity of the project. For instance, a 200 $MW_{ac}$ PV project with storage system rated at 100 MW capacity with four hours would be noted as having two hours of storage.*

There are three clusters of data in Figure B5.1. The data for Hawaii shows that on islands, solar PV and storage can provide significantly cheaper electricity than diesel-fired generators.[3] Compared to the price data for the mainland, it is also clear that costs will be higher due to the increased logistical and project development costs.

The second cluster represents a growing body of data that demonstrates utility-scale solar PV-storage hybrids can offer competitive electricity. The growth in this market is linked not only to the falling costs of solar PV and battery storage solutions, but likely in part due to the nature of solar PV. Solar PV experiences significant, but predictable, variation in output over the day. Generation rises from zero in the early morning to a peak during the middle of the day. In this respect, solar PV plants' grid connection is relatively expensive, as it is being utilised only partially, except for a very short period of time each day.

Storage allows even higher inverter-load ratios (ILRs)[4] to 'clip' peak production, increasing the utilisation of the smaller grid connection for a greater number of hours and using storage to capture what would otherwise be lost energy in the middle of the day and releasing it in the evening. This can further reduce grid connection costs and result in higher electricity market 'capture' prices.

The figure shows that over the 2018 to 2020 period, hybrid, utility-scale solar PV with battery storage of between 0.5 hours and 3.6 hours was contracted at between USD 0.029/kWh and USD 0.044/kWh. It is worth noting that RenewPower, the owner of the winning Indian bid for the supply of 300 MW for 3 hours of morning and 3 hours of evening 'peak' time, required only 0.5 hours of storage (150 MWh). This is because its project combines solar PV, onshore wind and battery storage – a timely reminder of the complementary nature of different renewable power generation sources in smoothing volatility and meeting electricity demand in real time.

The final data point of note is the Dubai Electricity and Water Authority (DEWA) 700 MW CSP plant. This has a PPA price of USD 0.073/kWh – with around 15 hours of storage. Indeed, although lithium-ion battery prices are rapidly falling, the economic limit of four hours of storage can clearly be seen in the solar PV and battery storage configurations.

CSP in areas of high direct normal irradiance (DNI) therefore potentially represents a bridge from solar PV, with four hours of storage, to very high shares of solar in the system, as CSP still represents the cheapest source of long duration storage. With good cost reduction potential still to be unlocked, given that less than 7 GW of CSP has been deployed globally, CSP could play a key role in integrating very high shares of solar PV and onshore wind. An additional advantage is that in areas with excellent solar resources, extremely competitive solar PV can naturally be paired with CSP to allow round the clock generation. The confluence of extremely low-cost solar PV, onshore and even offshore wind – as well as the expansion of CSP – could transform the electricity systems of countries in the sunbelt.

*3 In February 2021, when NYMEX crude oil prices were around USD 59/barrel of oil (bbl), Hawaii Electric Light Company Inc. was purchasing fossil fuel electricity at an average of USD 0.149/kWh (Hawai'i Electric Light Company Inc, 2021).*

*4 The ILR is the ratio of the DC capacity to the AC inverter rating. In the United States, this increased from around 1.2 in 2010 to 1.31 in 2019 (LBNL, 2020).*

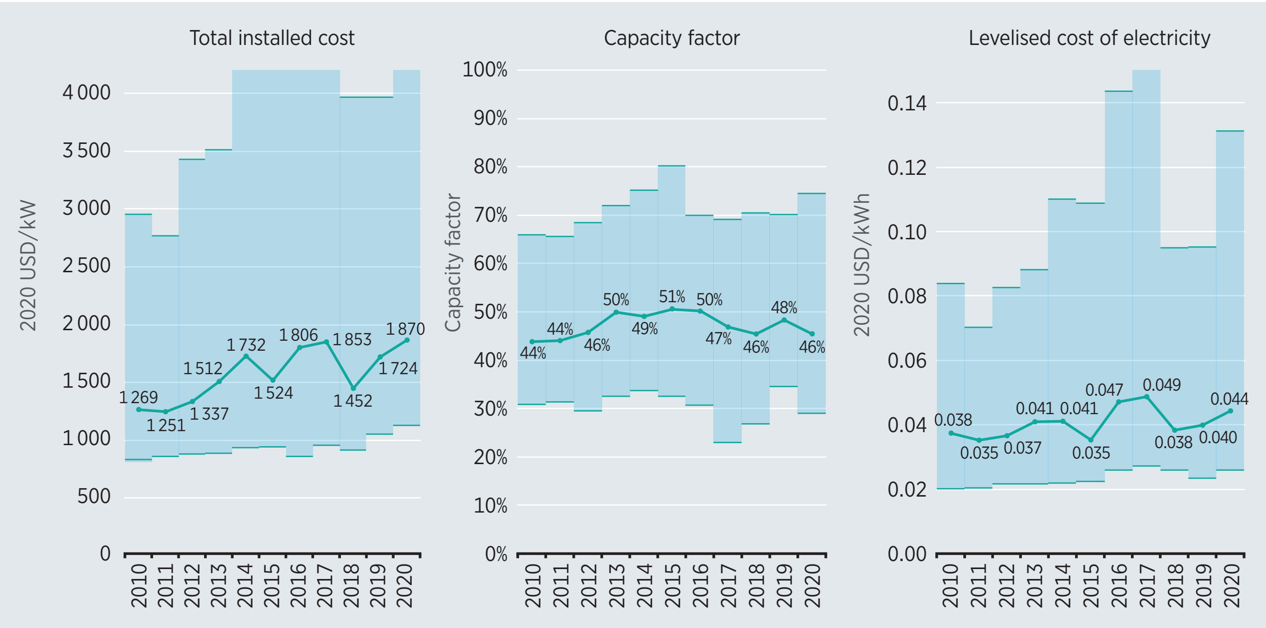
06

# HYDROPOWER

## HIGHLIGHTS

- The global weighted-average LCOE of newly commissioned hydropower projects in 2020 was USD 0.044/kWh – 10% higher than the USD 0.040/kWh recorded in 2019 and 16% higher than the projects commissioned in 2010 (Figure 6.1).
- With the cost of the newly commissioned fossil-fuel fired capacity ranging between USD 0.055/kWh and USD 0.148/kWh, 99% of the hydropower projects commissioned in 2020 had an LCOE within or lower than this range. Moreover, 56% of the hydropower projects commissioned in 2020 had an LCOE lower than the cheapest new fossil fuel-fired cost option.
- The increase in LCOE since 2010 has been driven by rising installed costs, notably in Asia, which have been driven by the increased number of projects with more expensive development conditions compared to earlier projects. This is likely due to an increase in projects in locations with more challenging site conditions.
- In 2020, the global weighted-average total installed cost of newly commissioned hydro projects increased to USD 1870/kW, 9% higher than in in 2019. Despite the higher share of deployment occurring in China in 2020 – 12 GW compared to 5.5 GW in 2019 – the global weighted-average total installed cost in 2020 was the highest recorded value since 2010. This increase is explained by the higher share of installed capacity deployment in other countries or regions with higher average installed costs. In Turkey, for example, 2.5 GW was added in 2020, while there was also a higher share of deployment in Eurasia and Other Asia in 2020 compared to 2019 – all locations with higher than average installed costs.
- Between 2010 and 2020, the global weighted-average capacity factor for hydropower projects commissioned varied between a low of 44% in 2010 to a high of 51% in 2015. For projects commissioned in 2020, it was 46%.

**Figure 6.1** Global weighted-average total installed costs, capacity factors and LCOE for hydropower, 2010-2020




*Source: IRENA Renewable Cost Database.*

Hydropower is both mature and reliable and is also the most widely deployed renewable generation technology, even though its share of global renewable energy capacity has been slowly declining. Indeed, hydropower's share fell from 72% in 2010 (881 GW) to 41% in 2020, although by the end of that year, total global installed hydropower capacity (excluding pumped hydro) had risen to 1 153 GW.

Hydropower provides a low-cost source of electricity and, if the plant includes reservoir storage, also provides a source of flexibility. This enables the plant to provide flexibility services, such as frequency response, black start capability and spinning reserves. This, in turn, increases plant viability by increasing asset owner revenue streams, while enabling better integration of variable renewable energy sources to meet decarbonisation targets. In addition to the grid flexibility services hydropower can provide, it can also store energy over weeks, months, seasons or even years, depending on the size of the reservoir.

In addition, hydropower projects combine energy and water supply services. These can include irrigation schemes, municipal water supply, drought management, navigation and recreation, and flood control – all of which provide local socio-economic benefits. Indeed, in some cases the hydropower capability is developed because of an existing need to manage river flows, with hydropower incorporated into the design.

While these additional services increase the viability of hydropower projects, the LCOE analysis carried out in this report, however, does not calculate the value of any services, outside of electricity generation, which are not site and power market specific.

## TOTAL INSTALLED COSTS

The construction of hydropower projects varies in size and properties, influenced by the location of the project. There are also key technical characteristics which determine the type and size of turbine used.

These key parameters include, among other factors, the 'head' (which is the water drop to the turbine determined by the location and design); the reservoir size; the minimum downstream flow rate; and seasonal inflows.

Hydropower plants fall under three categories:

- Reservoir, or storage hydropower, which provides a decoupling of hydro inflows from the turbines, with the water storage serving as a buffer that dams can use to store or regulate hydro inflows, decoupling the time of generation from the inflow.
- Run-of-river hydropower, in which hydro inflows mainly determine generation output, because there is little or no storage to provide a buffer for the timing and size of inflows.
- Pumped storage hydropower, in which there are upper and lower storage reservoirs and electricity is used to pump water from the lower to the upper reservoir in times of low demand (mostly during off-peak periods[27]) to be released in times of high electricity demand. Pumped hydro is mostly used for peak generation, grid stability and ancillary services. It can also be used to integrate more variable renewables by storing abundant renewable generation that is not needed during periods of low electricity demand.

Hydropower is a capital intensive technology, often requiring long lead times, with this especially true for large capacity projects. The lead time involves development, permitting, site development, construction and commissioning. Hydropower projects are large, complex, civil engineering projects and extensive site surveys, collection of inflow data (if not already available), environmental assessments and permitting all take time. These often have to be completed before site access and preparation can be undertaken.

There are two major costs components for hydropower projects:

- The civil works for the hydropower plant construction, which include any infrastructure development required to access the site, grid connection, any works associated with mitigating identified environmental issues and the project development costs.
- The procurement costs related to electro-mechanical equipment.

Civil construction work (which includes the dam, tunnels, canal and construction of the powerhouse) usually makes up the largest share of total installed costs for large hydropower plants (Table 6.1). Following this, costs for fitting out the powerhouse (including shafts and electro-mechanical equipment, in specific cases) are the next largest capital outlay, accounting for around 30% of the total costs.

The long lead times for these types of hydropower projects (7-9 years or more) means that owner costs (including project development costs) can also be a significant portion of the overall costs, due to the need for working capital and interest during construction.

Additional items that can add significantly to overall costs include the pre-feasibility and feasibility studies, consultations with local stakeholders and policy makers, environmental and socio-economic mitigation measures and land acquisition.

In certain circumstances, however, cost shares can vary widely. This is especially true if a project is adding capacity to an existing hydropower dam or river scheme, or where hydropower is being added to an existing dam that was developed without electricity generation in mind.

The total installed costs for the majority of hydropower projects commissioned between 2010 and 2020 range from a low of around USD 600/kW to a high of around USD 4 500/kW (Figure 6.2). It is not unusual, however, to find projects outside this range. For instance, adding hydropower capacity to an existing dam that was built for other purposes may have costs as low as USD 450/kW, while remote sites, with poor infrastructure and located far from existing transmission networks, can cost significantly more than USD 4 500/kW, due to higher logistical, civil engineering and grid connection costs.

Between 2010 and 2020, the global weighted-average total installed cost of new hydropower rose from USD 1 269/kW to USD 1 870/kW. There was some volatility, year-on-year, with increases driven by the share of deployment in different regions and changes in project-specific costs.

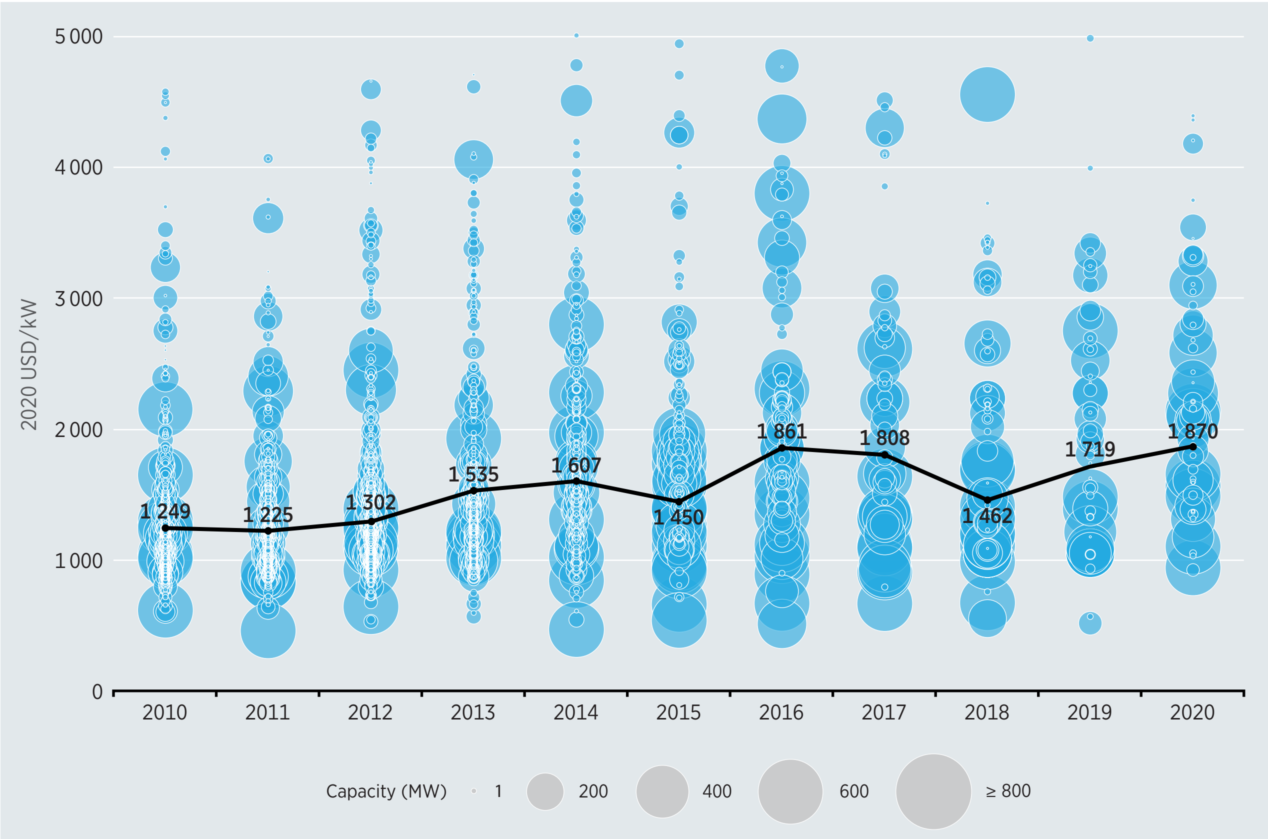
*Between 2010 and 2020, the global weighted-average total installed cost of new hydropower rose to USD 1 870/kW.*

**Table 6.1** Total installed cost breakdown by component and capacity-weighted averages for 25 hydropower projects in China, India and Sri Lanka, 2010-2016

| Project component | Share of total installed costs (%) | | |
|---|---|---|---|
| | Minimum | Weighted average | Maximum |
| **Civil works** | 17 | **45** | 65 |
| **Mechanical equipment** | 18 | **33** | 66 |
| **Planning and other** | 6 | **16** | 29 |
| **Grid connection** | 1 | **6** | 17 |
| **Cost of land** | 1 | **3** | 8 |

*Source: IRENA Renewable Cost Database.*

**Figure 6.2** Total installed costs by project and global weighted average for hydropower, 2010-2020




*Source: IRENA Renewable Cost Database.*

*Note: This chart excludes data for off-grid electrification projects. The global weighted-average total installed cost therefore differs to Figure 6.1 in some years.*

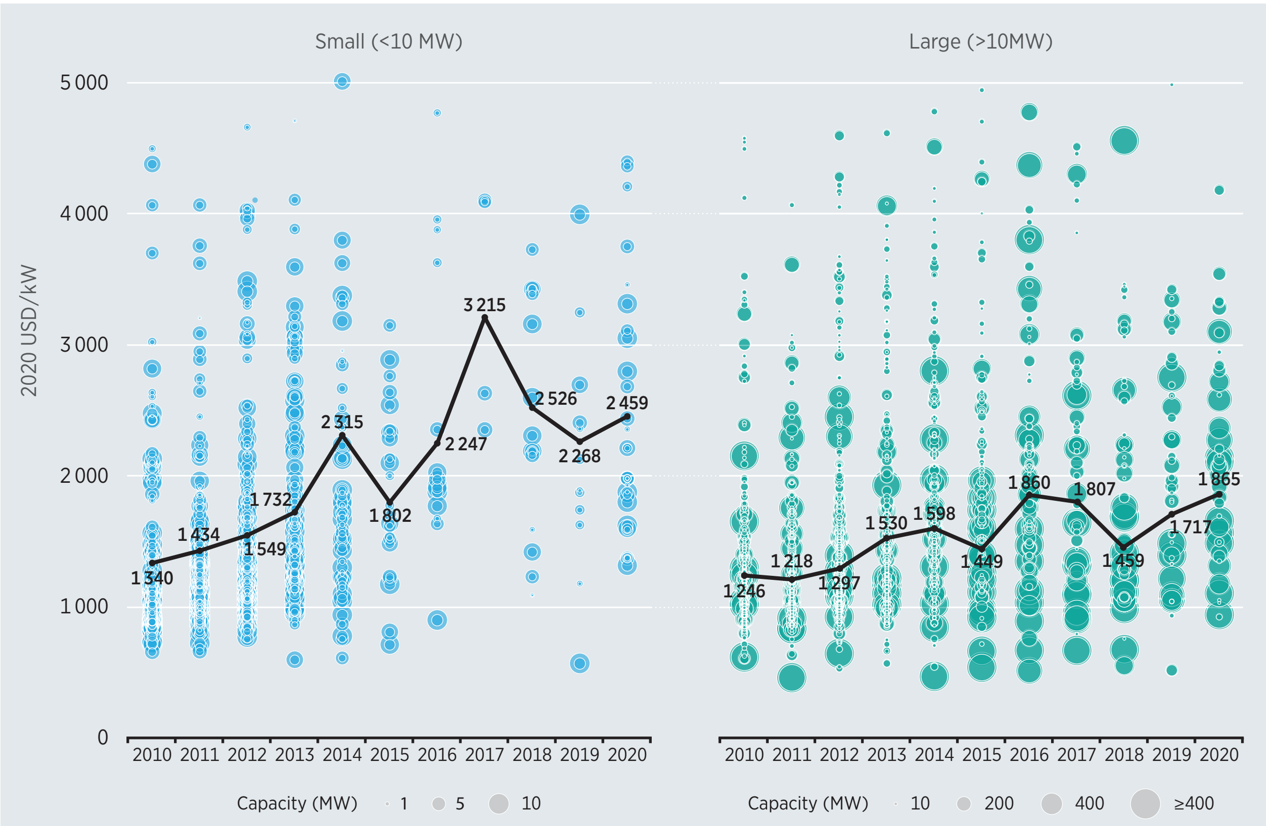
The increase has been driven by rising installed costs for projects in Asia, Europe and South America. The data appears to suggest that many countries in these regions are now developing hydropower projects at less ideal sites. Such projects are located further from existing infrastructure, or from the transmission network, resulting in higher logistical costs, as well as boosting grid connection costs. This results, overall, in higher installation costs.

Looking at the global weighted-average total installed cost trends for large hydro (greater than 10 MW in capacity) and small hydro (10 MW or less) suggests that average installed costs for small hydro have increased at a faster rate than for large hydro projects (Figure 6.3). This trend remains to be confirmed, however, given that data in the IRENA Renewable Cost Database for small hydropower projects is noticeably thinner for the years 2016 to 2018.

The full dataset of hydropower projects in the IRENA Renewable Cost Database for the years 2000 to 2020 (Table 6.2) does not suggest that there are strong economies of scale in hydropower projects below around 450 MW in size. The number of projects is not evenly distributed, however, and could likely support different hypotheses. There are clearly economies of scale for projects above 700 MW, but these only represent about 6% of the data capacity for hydropower for the period of commissioning between 2000 and 2020.

Figure 6.4 presents the distribution of total installed costs by capacity for small and large hydropower projects in the IRENA Renewable Cost Database. As the global weighted-average has risen over the two periods, it is possible to see the reason for this in the large hydropower data.

**Figure 6.3** Total installed costs for small and large hydropower projects and the global weighted-average, 2010-2020



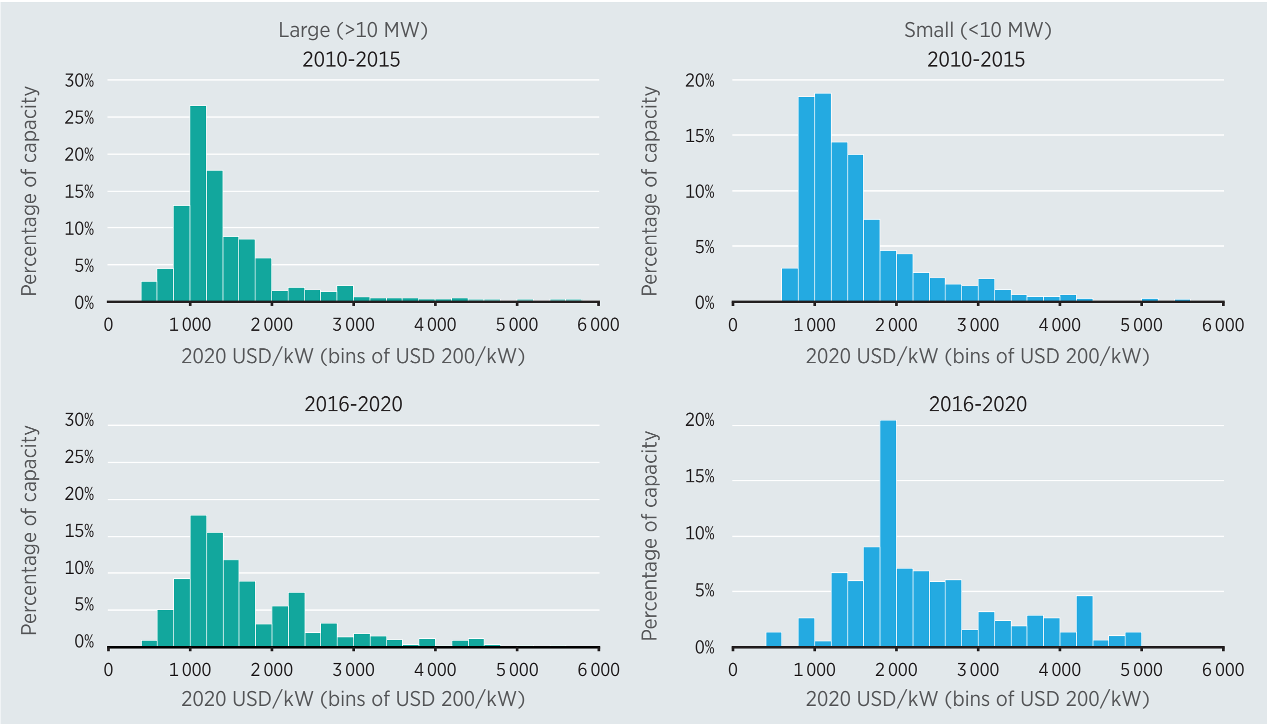

*Source: IRENA Renewable Cost Database.*

**Table 6.2** Total installed costs for hydropower by weighted-average and by capacity range, 2000-2020

| | 2000-2020 | | |
|---|---|---|---|
| Capacity (MW) | 5th percentile (2020 USD/kW) | weighted average (2020 USD/kW) | 95th percentile (2020 USD/kW) |
| **0-50** | 807 | **1 518** | 3 334 |
| **51-100** | 836 | **1 728** | 3 587 |
| **101-150** | 890 | **1 685** | 3 402 |
| **151-200** | 805 | **1 656** | 3 037 |
| **201-250** | 886 | **1 730** | 3 286 |
| **251-300** | 789 | **2 022** | 3 777 |
| **301-350** | 896 | **1 927** | 4 341 |
| **351-400** | 652 | **1 632** | 3 180 |
| **401-450** | 1 155 | **1 925** | 2 957 |
| **451-500** | 918 | **1 472** | 2 382 |
| **501-550** | 1 074 | **1 467** | 2 572 |
| **551-600** | 1 296 | **1 817** | 2 546 |
| **601-650** | 1 034 | **1 401** | 3 236 |
| **651-700** | 743 | **1 928** | 2 592 |
| **701-750** | 933 | **1 392** | 1 964 |
| **751-800** | 1 034 | **1 519** | 2 144 |
| **801-850** | 1 137 | **1 769** | 2 534 |
| **851-900** | 8 261 | **1 368** | 1 802 |
| **901-950** | 635 | **1 063** | 1 292 |

*Source: IRENA Renewable Cost Database.*

**Figure 6.4** Distribution of total installed costs of large and small hydropower projects by capacity, 2010-2015 and 2016-2020




*Source: IRENA Renewable Cost Database.*

Compared to the period 2010 to 2015, the data for 2016 to 2020 shows a reduction in the share of newly commissioned projects in the USD 600/kW to USD 1 200/kW range and an increase in the capacity of projects above that. The shift in the distribution of small hydropower projects is more pronounced, but has also been accompanied by a reduction in the skew of the distribution of projects, although there has also been growth in the tail of more expensive projects, compared to the 2010 to 2016 period.

For the 2016 to 2020 period, the total installed costs for large hydropower (more than 10 MW) were highest in the Oceania and Central America and the Caribbean regions. In these two areas, there were weighted-average installed costs of USD 3 984/kW and USD 3 462/kW respectively. The next highest costs were in North America, where the weighted-average was USD 2 803/kW.

The lowest installed costs for large hydropower were in China and India (Figure 6.5). There, the weighted-average installed cost was USD 1 314/kW in China, while in India it was USD 1 373/kW. In Other Asia, the cost was USD 1 630/kW, while in Europe it was USD 1 943/kW. In Brazil, the cost was USD 1 466/kW, while in Other South America it was USD 2 029/kW. In Eurasia and Africa the weighted-average installed costs were USD 2 172/kW and USD 2 417/kW, respectively. Unsurprisingly, regions with higher costs tended to have lower deployment rates.

Due to the very site-specific development costs of hydropower projects, the range in installed costs for hydropower tends to be wide.

Part of this is due to variations in the cost of development, civil engineering, logistics and grid connection. Some variation may also be driven by the non-energy requirements integrated into different projects. These can include, for example, obligations to provide other services, such as potable water, flood control, irrigation and navigation. These services are included in the hydropower project costs, but are typically not remunerated. It is therefore worth noting that these benefits are not included in the LCOE calculations in this chapter.

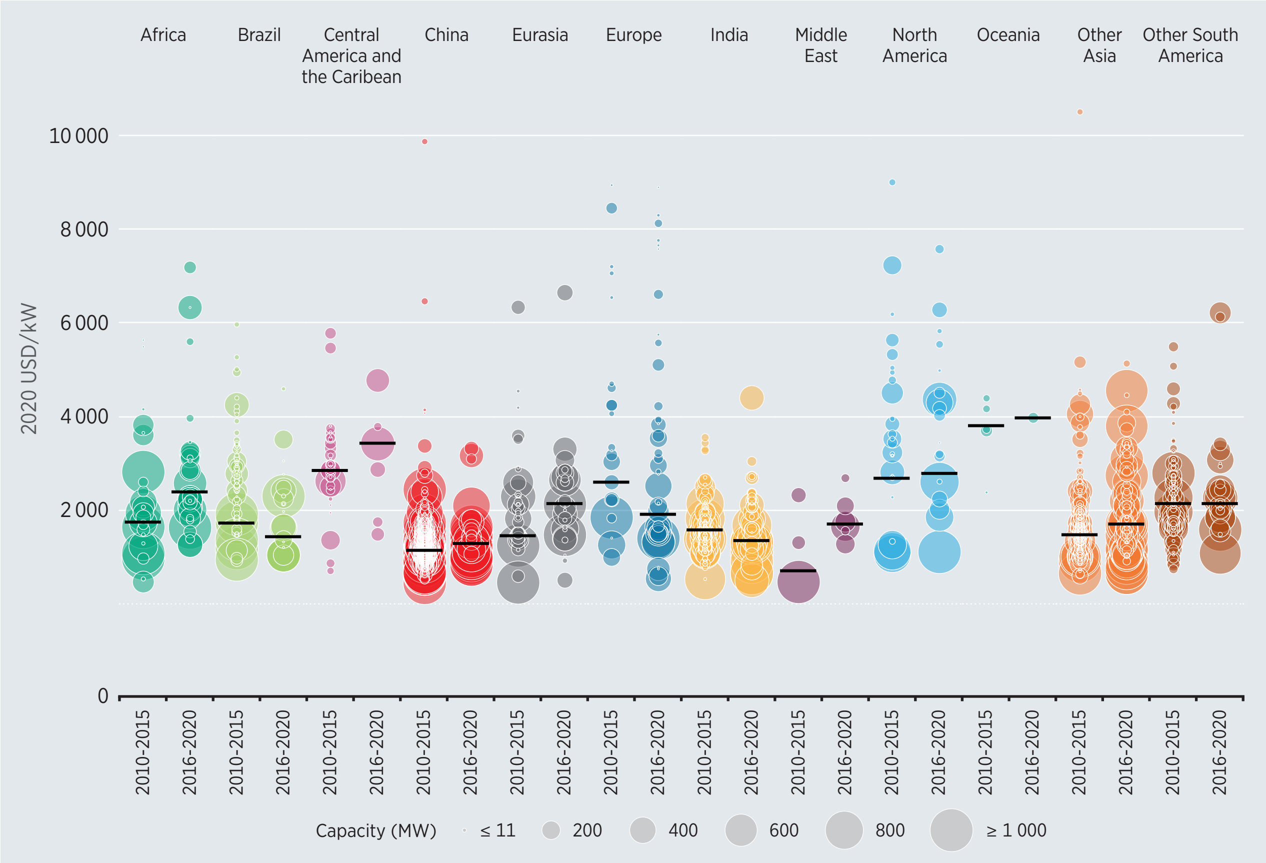
A comparison between installed costs for large and small hydro plants shows that small hydro plants generally have between 20% and 80% higher installed costs when compared to large hydro plants. The exceptions are in the Central America and the Caribbean and Oceania regions, where installed costs are higher for large hydropower plants as a result of the relatively small number of large projects developed in those regions (Figure 6.6).

Total installed costs for small hydropower projects between 2016 and 2020 in Brazil were USD 2 291/kW, which is somewhat lower than in the period 2010 to 2015. The total installed costs of small hydropower in India averaged USD 1 817/kW in the period 2016 to 2020, a figure 4% higher than in the period 2010 to 2015. The weighted-average installed cost for small hydropower in China was USD 1 171/kW over the period 2010 to 2015, with the data for the period 2016 to 2020 limited and unrepresentative.

The data for small hydropower projects commissioned in the period 2016 to 2020 is sparse in Central America and the Caribbean, Oceania and the Other South America regions. Results are therefore presented only for total installed costs for the period 2010 to 2015.

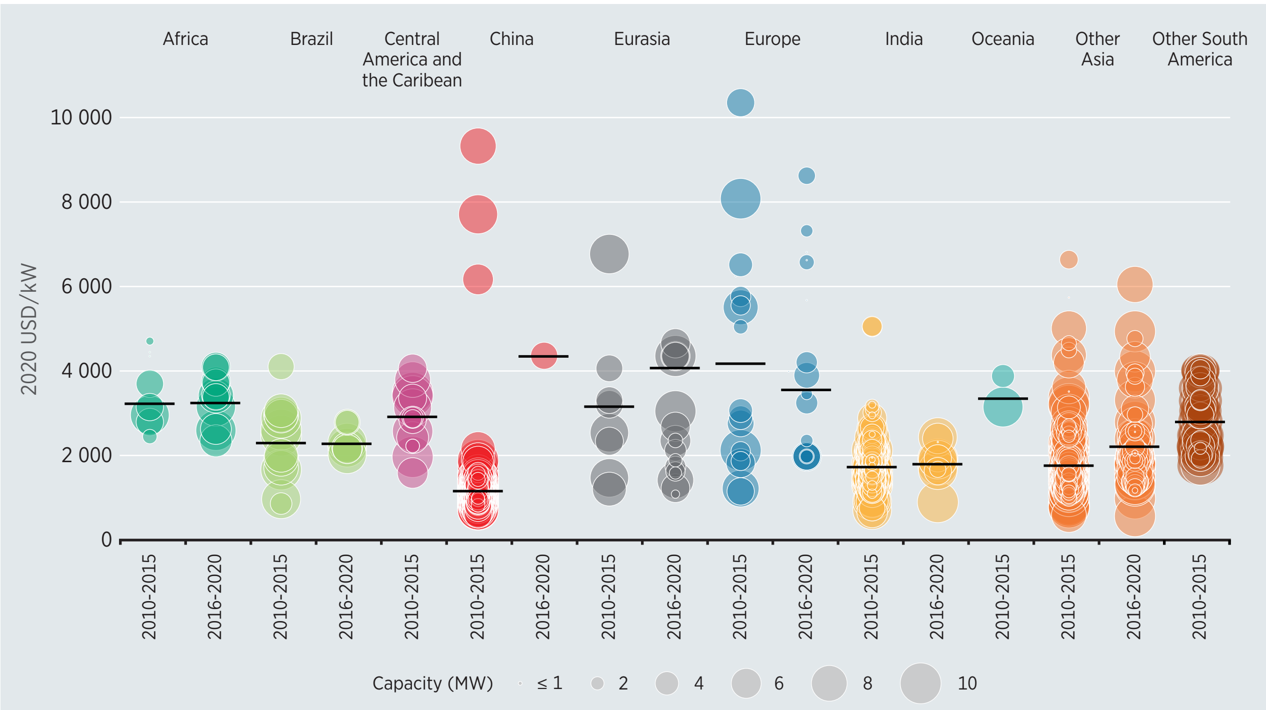
The weighted-average installed cost for small hydropower in Oceania was USD 3 364/kW over the period 2010 to 2015, while in Central America and the Caribbean it was USD 2 926/kW and in Other South America USD 2 810/kW.

**Figure 6.5** Total installed cost by project and capacity weighted averages for large hydropower projects by country/region, 2010-2020




*Source: IRENA Renewable Cost Database.*

**Figure 6.6** Total installed costs by project and capacity weighted averages for small hydropower projects by country/region, 2010-2020




*Source: IRENA Renewable Cost Database.*

## CAPACITY FACTORS

Between 2010 and 2020, the global weighted-average capacity factor of newly commissioned hydropower projects of all sizes increased from 44% to 46%, with an average of 47% in the period 2010 to 2020. The 5$^{th}$ and 95$^{th}$ percentiles of projects over this period stayed within the range 23% to 80%. This wide spread overall is to be expected, given that each hydropower project has very different site characteristics, while in addition, low capacity factors are sometimes a design choice, with turbines sized to help meet peak demand and provide other ancillary grid services.

The average capacity factor for projects commissioned between 2010 and 2020 was 52% for small hydro projects and 47% for large, with most projects in the range of 25% to 80% (Tables 6.3 and 6.4). Europe was a notable exception, having a range of projects with capacity factors lower than 20%.

Between 2010 and 2020, the annual global weighted-average capacity factors of the 5$^{th}$ percentile of large hydropower projects ranged from a low of 23% in 2017, to a high of 29% in 2020. For the 95$^{th}$ percentile, the figure ranged from a low of 61% in 2010, to a high of 80% in 2015. The figure for 2020 was 73%.

Between 2010 and 2020, the global weighted-average capacity factor of newly-commissioned small hydropower projects was 52%. Excluding the years 2017 and 2018 where there is a lack of data, between 2010 and 2020 the annual, global weighted-average capacity factors of the 5$^{th}$ percentile of small hydropower projects ranged from a low of 29% in 2012 to a high of 39% in 2016. For the 95$^{th}$ percentile, these capacity factors ranged from a low of 69% in 2011, to a high of 81% in 2016.

In the IRENA database, there is often a significant regional variation in the weighted-average capacity factor. Tables 6.3 and 6.4 represent hydropower project capacity factors and capacity weighted averages for large and small hydropower projects by country and region.

Between 2010 and 2015, average capacity factors for newly-commissioned large hydropower projects were highest in Brazil and South America, with 61% and 62%, respectively, while between 2015 and 2020, South America maintained the highest average capacity factor, at 60%, followed by 55% for Africa. Meanwhile, between 2010 and 2015, North America recorded the lowest average capacity factor for newly-commissioned large hydropower projects, with 37%, while between 2016 and 2020, Europe had the lowest recorded, at 33%.

Small hydropower projects (less than 10 MW) showed a smaller range of country-level, weighted-average variation (Table 6.4). For these, there were country-level average lows of 46% and 38% in China, during the periods 2010 to 2015 and 2016 to 2020, respectively. Similarly, weighted-average capacity factors for newly-commissioned small hydropower projects between 2010 and 2014 were highest in Other South America and Brazil, with 65% and 63%, respectively.

Between 2015 and 2019, due to the limited number of newly commissioned small hydropower projects in the database for Other South America, this region's weighted-average capacity factor was considered not representative. Eurasia showed the highest weighted-average capacity factor for this period, with 61%, followed by India, with a factor of 57%, while Brazil's dropped to 45%.

**Table 6.3** Hydropower weighted-average capacity factors and ranges for large hydropower projects by country/region, 2010-2020

| | 2010-2015 | | | 2016-2020 | | |
|---|---|---|---|---|---|---|
| | 5th percentile (%) | Weighted-average (%) | 95th percentile (%) | 5th percentile (%) | Weighted-average (%) | 95th percentile (%) |
| **Africa** | 28 | **47** | 71 | 37 | **55** | 79 |
| **Brazil** | 51 | **61** | 80 | 39 | **45** | 57 |
| **Central America** | 27 | **48** | 63 | 35 | **53** | 55 |
| **China** | 31 | **45** | 57 | 34 | **47** | 56 |
| **Eurasia** | 28 | **43** | 61 | 29 | **42** | 67 |
| **Europe** | 14 | **41** | 70 | 16 | **33** | 59 |
| **India** | 29 | **47** | 63 | 21 | **42** | 56 |
| **North America** | 18 | **37** | 78 | 34 | **50** | 69 |
| **Oceania** | 25 | **38** | 47 | n.a. | **n.a.** | n.a. |
| **Other Asia** | 37 | **46** | 65 | 40 | **50** | 76 |
| **Other South America** | 46 | **62** | 85 | 47 | **60** | 79 |

*Source: IRENA Renewable Cost Database.*

**Table 6.4** Hydropower weighted-average capacity factors and ranges for small hydropower projects by country/region, 2010-2020

| | 2010-2014 | | | 2015-2019 | | |
|---|---|---|---|---|---|---|
| | 5th percentile (%) | Weighted-average (%) | 95th percentile (%) | 5th percentile (%) | Weighted-average (%) | 95th percentile (%) |
| **Africa** | 33 | **56** | 68 | 50 | **55** | 61 |
| **Brazil** | 42 | **63** | 88 | 53 | **56** | 59 |
| **Central America** | 45 | **59** | 75 | n.a. | **n.a.** | n.a. |
| **China** | 33 | **46** | 60 | 38 | **38** | 38 |
| **Eurasia** | 44 | **58** | 74 | 52 | **61** | 70 |
| **Europe** | 23 | **48** | 70 | 33 | **44** | 68 |
| **India** | 28 | **50** | 71 | 48 | **57** | 61 |
| **Other Asia** | 37 | **50** | 79 | 35 | **54** | 80 |
| **Other South America** | 43 | **65** | 82 | n.a. | **n.a.** | n.a. |

*Source: IRENA Renewable Cost Database.*

## OPERATION AND MAINTENANCE COSTS

Annual O&M costs are often quoted as a percentage of the investment cost per kW per year, with typical values ranging from 1% to 4%.

IRENA previously collected O&M data on 25 projects (IRENA, 2018) and found average O&M costs varied between 1% and 3% of total installed costs per year, with an average that was slightly less than 2%.

Larger projects have O&M costs below the 2% average, while smaller projects approach the maximum, or are higher than the average O&M cost.

Table 6.5 presents the cost distribution of individual O&M items in the sample. As can be seen, operations and salaries take the largest slices of the O&M budget. Maintenance varies from 20% to 61% of total O&M costs, while salaries vary from 13% to 74%. Materials are estimated to account for around 4% (Table 6.5).

The International Energy Agency (IEA) assumes O&M costs of 2.2% for large hydropower projects and 2.2% to 3% for smaller projects, with a global average of around 2.5% (IEA, 2010). This would put large-scale hydropower plants in a similar range of O&M costs – expressed as a percentage of total installed costs – as those for wind, although not as low as the O&M costs for solar PV. When a series of plants are installed along a river, centralised control, remote management and a dedicated operations team to manage the chain of stations can also reduce O&M costs to much lower levels.

Other sources, however, quote lower or higher values. For a conventional, 500 MW hydropower plant commissioned in 2020, the Energy Information Agency (EIA), for example, assumes 0.06% of total installed costs as fixed annual O&M costs, along with USD 0.003/kWh as variable O&M costs (EIA, 2017a).

Other studies (EREC/Greenpeace, 2010) indicate that fixed O&M costs represent 4% of the total capital cost. This figure may represent small-scale hydropower, with large hydropower plants having significantly lower O&M costs. An average value for O&M costs of 2% to 2.5% is considered the norm for large-scale projects (IPCC, 2011), which is equivalent to average costs of between USD 20/kW/year and USD 60/kW/year for an average project, by region, in the IRENA Renewable Cost Database.

O&M costs usually include an allowance for the periodic refurbishment of mechanical and electrical equipment, such as turbine overhaul, generator rewinding and reinvestments in communication and control systems. Yet, they usually exclude major refurbishments of the electro-mechanical equipment, or the refurbishment of penstocks, tailraces, etc. Replacement of these is infrequent, with design lives of 30 years or more for electro-mechanical equipment and 50 years or more for penstocks and tailraces. This means that the original investment has been completely amortised by the time these investments need to be made, and therefore they are not included in the LCOE analysis presented here. They may, however, represent an economic opportunity before the full amortisation of the hydropower project, in order to boost generation output.

**Table 6.5** Hydropower project O&M costs by category from a sample of 25 projects

| Project Component | Share of total O&M costs (%) | | |
|---|---|---|---|
| | Minimum | Weighted average | Maximum |
| **Operation costs** | 20 | **51** | 61 |
| **Salary** | 13 | **39** | 74 |
| **Other** | 5 | **16** | 28 |
| **Material** | 3 | **4** | 4 |

*Source: IRENA Renewable Cost Database.*

## LEVELISED COST OF ELECTRICITY

Hydropower has historically provided the backbone of low-cost electricity in a significant number of countries around the world. These range from Norway to Canada, New Zealand to China, and Paraguay to Brazil and Angola – to name just a few. Investment costs are highly dependent on location and site conditions, however, which explains the wide range of plant installed costs, and also much of the variation in LCOE between projects. It is also important to note that hydropower projects can be designed to perform very differently from each other, which complicates a simple LCOE assessment.

As an example, a plant with a low installed electrical capacity could run continuously to ensure high average capacity factors, but at the expense of being able to ramp up production to meet peak demand loads. Alternatively, a plant with a high installed electrical capacity and low capacity factor, would be designed to help meet peak demand and provide spinning reserve and other ancillary grid services. The latter strategy would involve higher installed costs and lower capacity factors, but where the electricity system needs these services, hydropower can often be the cheapest and most effective solution for these needs.

The strategy pursued in each case will depend on the characteristics of the site inflows and the needs of the local market. This is before taking into account the increasing value of hydropower systems with significant reservoir storage, which can provide very low cost and long-term electricity storage to help facilitate the growing share of variable renewable energy.

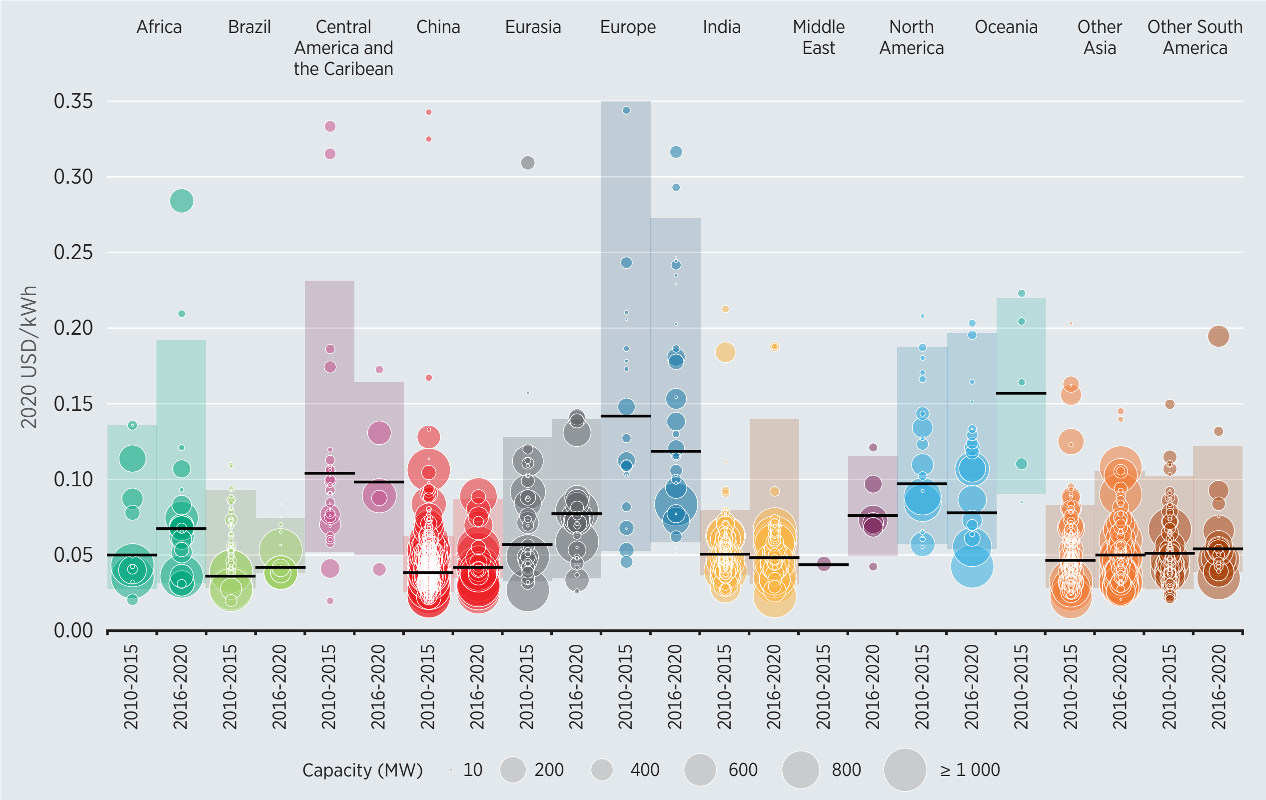
In 2020, the global weighted-average cost of electricity from hydropower was USD 0.044/kWh, up 16% from the USD 0.038/kWh recorded in 2010. The global weighted-average cost of electricity from hydropower projects commissioned in years 2010 to 2015 averaged USD 0.038/kWh. This increased to an average of USD 0.044/kWh for projects commissioned over the years 2016 to 2020.

Despite these increases through time, however, 99% of the hydropower projects commissioned in 2020 had an LCOE within or lower than this range. Moreover, 56% of the hydropower projects commissioned in 2020 had an LCOE lower than the cheapest new fossil fuel-fired cost option. This was before considering that a significant proportion of those projects with costs above the lowest fossil fuel cost may have been deployed in remote areas, where it was still the cheapest source of new electricity, given the extensive use of small hydropower, in particular, in providing low-cost electricity in remote locations, and for overall electrification.

The weighted-average country/regional LCOE of hydropower projects, large and small, in the IRENA Renewable Cost Database reflects the variation in site-specific and country-specific project installed costs and capacity factors. The figures for projects by country commissioned in 2020 range from a low of USD 0.034/kWh in India to a high of USD 0.14/ kWh in North America, where very little new capacity was added in 2019.

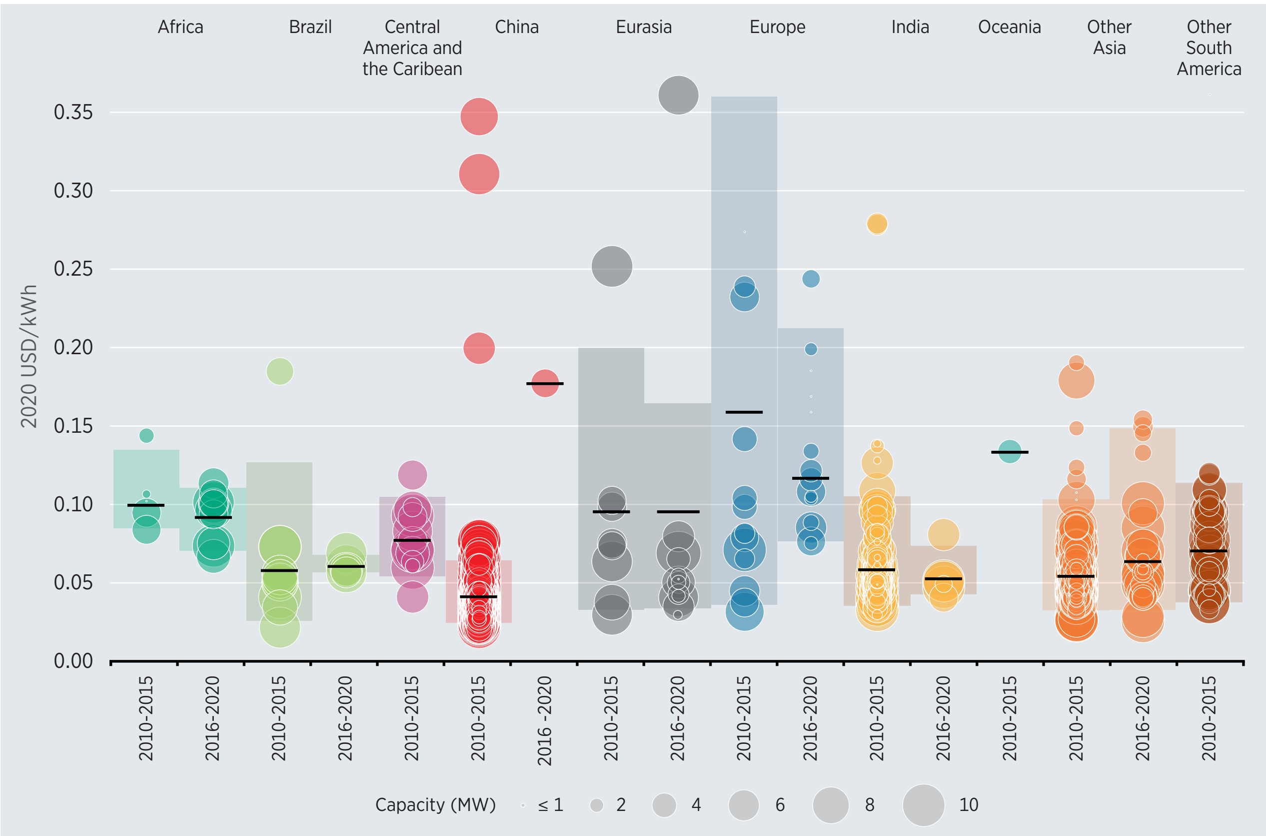
Figure 6.7 and Figure 6.8 present the LCOEs of large and small hydropower projects and the capacity weighted averages by country/region. For large hydropower projects, a number of countries/regions saw an increase in the weighted-average LCOE between the periods 2010 to 2015 and 2016 to 2020. The exceptions were Europe and North America, where the weighted-average LCOE decreased, while China maintained relatively the same weighted-average LCOE, albeit with a slight increase. Small hydropower projects showed similar trends in Brazil and Europe, but a different trend in Africa, where the weighted-average LCOE decreased.

**Figure 6.7** Large hydropower project LCOE and capacity weighted averages by country/region, 2010-2020




*Source: IRENA Renewable Cost Database.*

**Figure 6.8** Small hydropower project LCOE and capacity weighted averages by country/region, 2010-2020




*Source: IRENA Renewable Cost Database.*

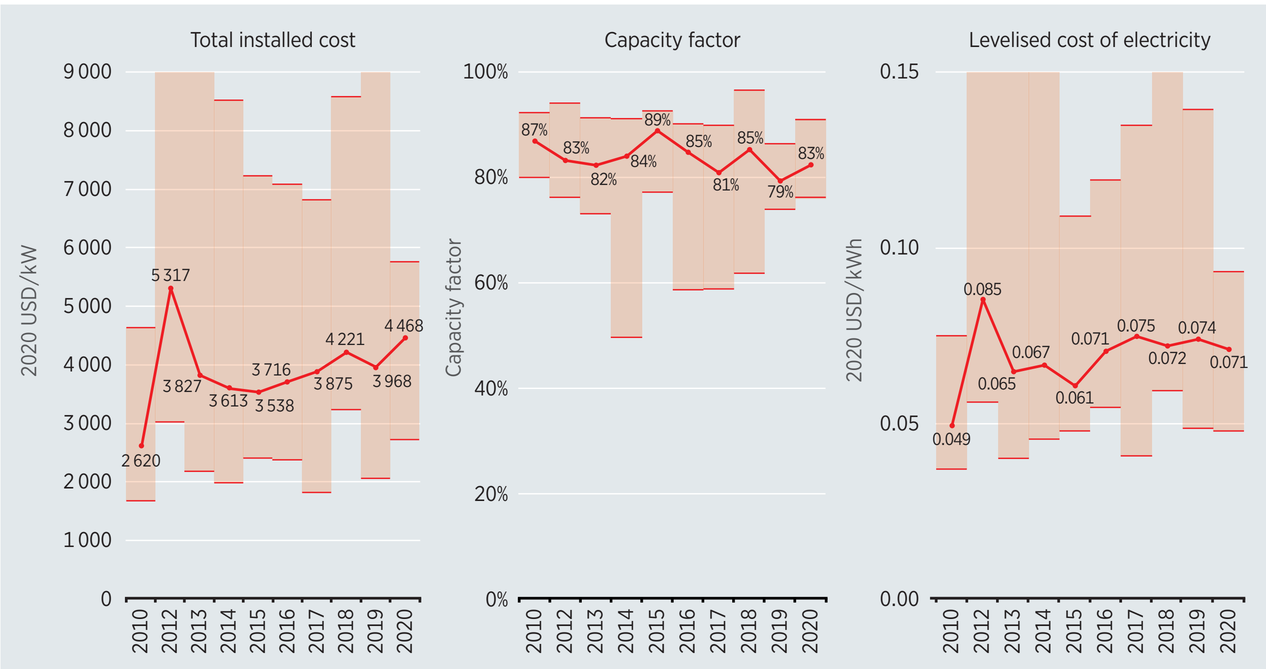
# 07

# GEOTHERMAL

## HIGHLIGHTS

- New geothermal power generation capacity commissioned in 2020 fell to 192 MW, down from the 682 MW added in 2019. The global weighted-average LCOE of the projects commissioned in 2020 was USD 0.071/kWh, slightly lower than in 2019, but broadly in line with values seen over the last four years.
- Between 2014 and 2019, annual new capacity additions were at least 440 MW. The lower deployment in 2020 means that weighted-average costs and performance are being determined by only a handful of plants. This is similar to the experience between 2010 and 2013, when annual new capacity additions varied between a low of 89 MW in 2011 and a high of 400 MW in 2012.
- In 2020, the global weighted-average total installed cost of the eight plants in IRENA's database was USD 4 486/kW, higher than the recent low of USD 3 538/kW set in 2015. The total installed costs of the eight projects commissioned in 2020 ranged from a low of USD 2 140/kW to a high of USD 6 248/kW.
- Geothermal plants are typically designed to run as often as possible to provide power round the clock. In 2020, the global weighted-average capacity factor for newly commissioned plants was 83%, while ranging from a low of 75% to a high of 91% for the projects in the IRENA database.

**Figure 7.1** Global weighted-average total installed costs, capacity factors and LCOE for geothermal, 2010-2020




*Source: IRENA Renewable Cost Database.*

## INTRODUCTION

The best geothermal resources are those found in active geothermal areas on or near the surface of the Earth's crust. These can be accessed at lower cost than the evenly distributed heat available at greater depths anywhere on the planet. By drilling into the earth's surface, the naturally occurring steam or hot water in active geothermal areas can be easily accessed and used to generate electricity in steam turbines.

Given the somewhat unique nature of geothermal resources, geothermal power generation is very different in nature to other renewable power generation technologies.

Indeed, developing a geothermal project presents a unique set of challenges when it comes to assessing the resource and how the reservoir will react once production starts. Sub-surface resource assessments are expensive to conduct and need to be confirmed by test wells that allow developers to build models of the reservoir's extent and flow. Much, however, will remain unknown about how the reservoir will perform and how best to manage it over the operational life of the project.

In addition to increasing development costs, these issues mean geothermal projects have very different risk profiles compared to other renewable power generation technologies, in terms of both project development and operation.

Geothermal resources consist of thermal energy, stored as heat in the rocks of the Earth's crust and interior. At shallow depths, fissures to deeper depths in areas saturated with water will produce hot water and/or steam that can be tapped for electricity generation at relatively low cost. Where this is not the case, geothermal energy can still be extracted, by drilling to deeper depths and injecting water into the hot area through wells — thus harnessing the heat found in otherwise dry rocks.

At the end of 2020, geothermal power generation stations accounted for 0.5% of the total installed renewable power generation capacity, worldwide, with a total installed capacity of 14 gigawatts (GW). Cumulative installed capacity at the end of 2020 was 41% higher than in 2010. This capacity is mostly located in active geothermal areas.

Geothermal is a mature, commercially proven technology. It can provide low cost, 'always-on' capacity in geographies with very good to excellent high-temperature conventional geothermal resources, close to the Earth's surface. The development of unconventional geothermal resources, however, using the 'enhanced geothermal' or 'hot dry rocks' approach, is much less mature. In this instance, projects come with costs that are typically significantly higher, due to the deep drilling required, rendering the economics of such initiatives currently much less attractive.

Research and development into more innovative, low-cost drilling techniques and advanced reservoir stimulation methodologies is needed. This would help lower development costs and realise the full potential of enhanced geothermal resources, by making them more economically viable.

One of the most important challenges faced when developing geothermal power generation projects lies in the availability of comprehensive geothermal resource mapping. Where it is available, this reduces the uncertainties that developers face during the exploration period, potentially reducing the development cost. This is because poorer than expected results during the exploration phase might require additional drilling, or wells may need to be deployed over a much larger area to generate the expected electricity. There is a potential role for governments in undertaking, at least some resource mapping and making this available to project developers, in order to reduce project development risks and costs to consumers.

Globally, around 78% of production wells drilled are successful, with the average success rate improving in recent decades. This is most likely due to better surveying technology, which is able to more accurately target the best prospects for siting productive wells, although greater experience in each region has also played a part. A key point is that adherence to global best practices significantly reduces exploration risks (IFC, 2013).

In addition, geothermal plants are very individual in terms of the quality of their resources and management needs. As a result, experience with one project may not yield specific lessons that can be directly applied to new developments. It may, however, provide broader industry knowledge that helps better inform other factors, from reservoir modelling to O&M practices. Nonetheless, adherence to best international practices for survey and management, with thorough data analysis from the project site, are the best risk mitigation tools available to developers (IFC, 2013).

Once commissioned, the management of a geothermal plant and its reservoir evolves almost constantly over time, as reservoir fluid is extracted and reinjected over the life of the project. Intervention in the reservoir creates a dynamic situation. With more information becoming available from operational experience, operators' understanding of how to best manage the reservoir will constantly evolve over time. An important consideration for geothermal power plants is that once productivity at existing wells declines, there might also be a need for replacement wells to make up for this loss.

*Geothermal power plants provide firm, 'always on' power, with capacity factors typically ranging between 60% to more than 90% depending on site conditions and plant design.*

## TOTAL INSTALLED COSTS

Just as with hydropower, solar and wind technologies, geothermal power plants are a capital-intensive. There are significant upfront costs for project development, field preparation, production and reinjection wells, the power plant and associated civil engineering. Geothermal projects are also subject to variations in drilling costs, the trends of which are often influenced by the business cycle in the oil and gas industry. These fluctuations have a direct impact on drilling costs and thus the costs of engineering, procurement and construction (EPC).

Geothermal power plant installed costs are highly site-sensitive, having more in common in this respect with hydropower projects than the more standardised, solar PV and onshore wind facilities. Geothermal power projects costs are heavily influenced by the reservoir quality, the type of power plant and the number of wells required. The nature and extent of the reservoir, the thermal properties of the reservoir and its fluids — and at what depths it lies — will all have an impact on project costs. The quality of the geothermal resource and its geographical distribution will determine the power plant type. This can range from flash, direct steam, binary, enhanced or a hybrid approach to provide the steam that will drive a turbine and create electricity. Typically, costs for binary plants designed to exploit lower temperature resources tend to be higher than those for direct steam and flash plants, as extracting the electricity from lower temperature resources is more capital intensive.

The total installed costs of geothermal power plants consist not only of the usual project development costs and the cost of the power plant and grid connection. They also include the costs of exploration and resource assessment (including seismic surveys and test wells), as well as drilling costs for the production and injection wells. Total installed costs also include field infrastructure, geothermal fluid collection and disposal systems and other surface installations.

In line with rising commodity prices and drilling costs, between 2000 and 2009, the total installed costs for geothermal plants increased by between 60% and 70% (IPCC, 2011). Project development costs followed general increases in civil engineering and EPC costs during that period, with cost increases in drilling associated with surging oil and gas markets. Costs appear to have stabilised in recent years, however. In 2009, the total installed costs of conventional condensing 'flash' geothermal power generation projects were between USD 2 044/kW and USD 4 078/kW. Binary power plants were more expensive and installed costs for typical projects were between USD 2 419/kW and USD 5 910/kW, that same year (IPCC, 2011).

Figure 7.2 presents the geothermal power total installed costs by project, technology and capacity, from 2007 to 2021. Based on the data available in the IRENA Renewable Cost Database, installed costs from 2010 onwards have generally fallen within the range of USD 2 000/kW to USD 7 000/kW, although there were a number of project outliers.[1] Since 2015, installation costs have shown an increasing trend, interrupted in 2019, when installed costs slightly decreased. In 2020, the global weighted-average total installed cost was USD 4 468/kW, up from the USD 3 968/kW recorded in 2019 and from the USD 2 620/kW reported in 2010. In the more exceptional case of projects where capacity is being added to an existing geothermal power project, the IRENA Renewable Cost Database suggests the cost of a geothermal power plant can be as low as USD 560/kW, but this by no means the norm.

1 *These outliers are typically either small projects in remote areas, or are not representative of typical costs for a variety of other reasons.*

**Figure 7.2** Geothermal power total installed costs by project, technology and capacity, 2007-2021


*Source: IRENA Renewable Cost Database.*

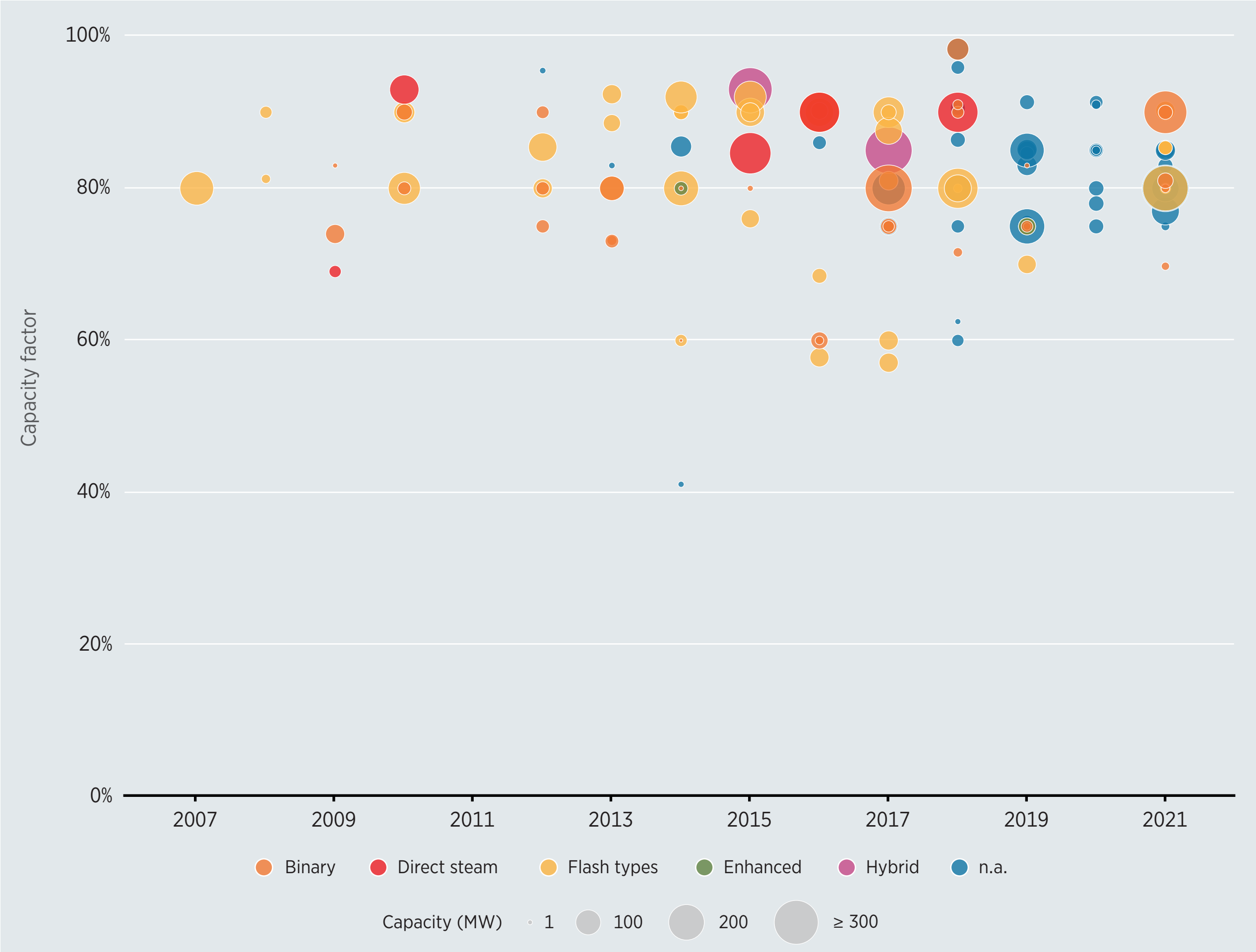
## CAPACITY FACTORS

For the years 2007-2021, the data from the IRENA Renewable Cost Database indicates that geothermal power plants typically have capacity factors that range between 60% to more than 90%. There are, however, significant variations by project, driven by resource quality issues and economic factors, to name just the two most important drivers.

Figure 7.3 presents the capacity factors of geothermal power plant projects, the project size and technology. For the data in the IRENA Renewable Cost Database, the average capacity factor of geothermal plants using direct steam is around 85%, while the average for flash technologies is 82%. Binary geothermal power plants that harness lower temperature resources are expected to achieve an average capacity factor of 78%.[2]

*2 In terms of the efficiency of conversion of the primary energy content (heat) to electricity, geothermal power plants report a worldwide average of 12% efficiency, while the upper range is situated at 21% for a vapour dominated plant (Zarrouk and Moon, 2014).*

**Figure 7.3** Capacity factors of geothermal power plants by technology and project size, 2007-2021




*Source: IRENA Renewable Cost Database.*

## LEVELISED COST OF ELECTRICITY

The total installed costs, weighted-average cost of capital, economic lifetime and O&M costs of a geothermal plant determine its LCOE. Even more so than solar and wind technologies, geothermal power projects require continuous optimisation throughout the lifetime of the project, with sophisticated management of the reservoir and production wells to ensure output meets expectations.

Figure 7.4 presents the LCOEs of geothermal power projects by technology and size for the period 2007 to 2021. During this period, the LCOE varied from as low as USD 0.04/kWh for second stage development of an existing field to as high as USD 0.17/kWh for small greenfield developments in remote areas.

The LCOE analysis assumed a project economic life of 25 years and O&M costs of USD 115/kW/year. Capacity factors were based on project data, if available. If they were not, national averages were used.

O&M costs for geothermal projects are high relative to onshore wind and solar PV, in particular, because over time the reservoir pressure around the production well declines. Well productivity therefore reduces over time and eventually power generation production as well, if remedial measures are not taken. In order to maintain production at the designed capacity factor, the reservoir and production profile of the geothermal power plants requires agile management, which will also typically mean the need to incorporate additional production wells over the lifetime of the plant. The O&M cost assumption of USD 115/kW/year therefore includes two sets of wells for makeup and re-injection over the 25-year life of the project, in order to maintain performance.

The global weighted-average LCOE increased from around USD 0.05/kWh for projects commissioned in 2010 to around USD 0.07/kWh in 2020. Although there are annual variations in the global weighted-average capacity factor of newly commissioned projects, this is often less significant than for some other technologies. As a result, the LCOE of geothermal power projects tends to follow the trends in total installed costs. For the period 2019 to 2021, the data available suggests the LCOE would remain stable at around USD 0.07/kWh. This will, however, depend on whether projects meet their commissioning goals and if not, whether cost overruns are incurred, particularly for the larger projects in the pipeline.

**Figure 7.4** LCOE of geothermal power projects by technology and project size, 2007-2021


*Source: IRENA Renewable Cost Database.*

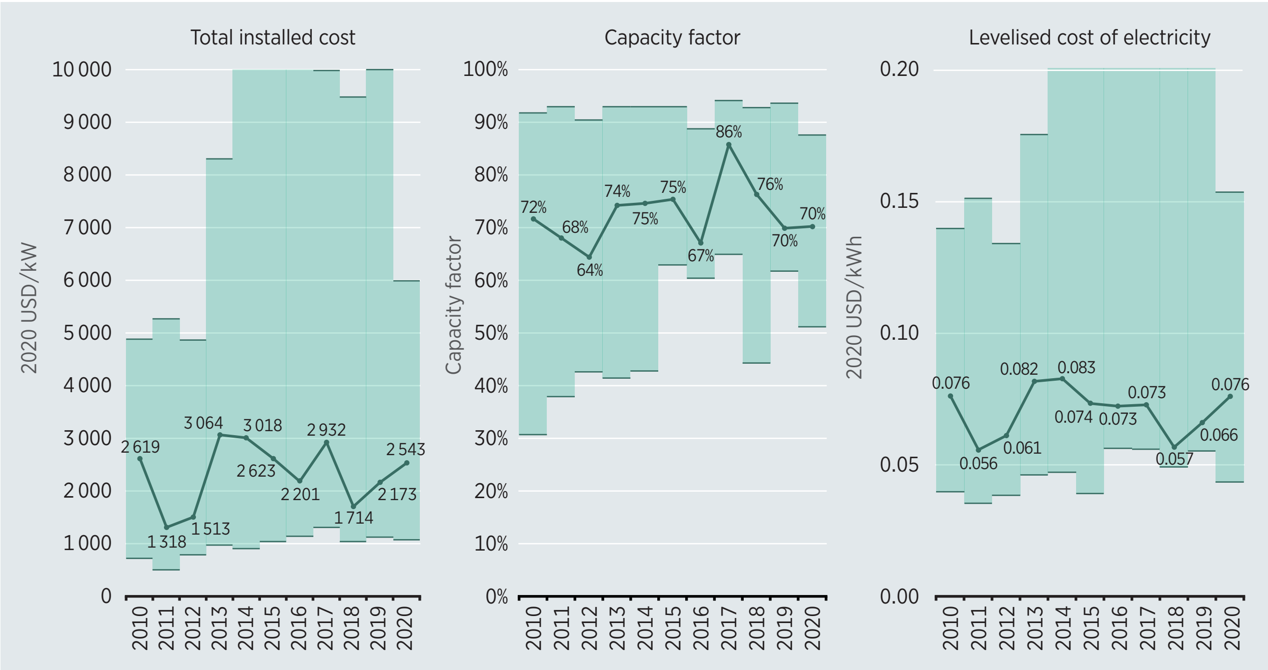
# 08

# BIOENERGY

## HIGHLIGHTS

- Between 2010 and 2020, the global weighted-average LCOE of bioenergy for power projects fell from USD 0.076/kWh in 2010 to USD 0.066/kWh in 2019. It then returned to USD 0.076/kWh in 2020. This was still a figure at the lower end of the cost of electricity from new, fossil fuel-fired projects.
- Bioenergy for electricity generation offers a suite of options, spanning a wide range of feedstocks and technologies. Where low-cost feedstocks are available – such as by-products from agricultural or forestry processes onsite – they can provide highly competitive, dispatchable electricity.
- For bioenergy projects newly commissioned in 2020, the global weighted-average total installed cost was USD 2 543kW (Figure 8.1). This represented an increase on the 2019 weighted-average of USD 2 173/kW.
- Capacity factors for bioenergy plants are very heterogeneous, depending on technology and feedstock availability. Between 2010 and 2020, the global weighted-average capacity factor for bioenergy projects varied between a low of 65% in 2012 to a high of 86% in 2017, decreasing to 70% in both 2019 and 2020.
- In 2020, the weighted-average LCOE ranged from a low of USD 0.057/kWh in India and USD 0.06/kWh in China, to highs of USD 0.087/kWh in Europe and USD 0.097/kWh in North America.

**Figure 8.1** Global weighted-average total installed costs, capacity factors and LCOE for bioenergy, 2010-2020




*Source: IRENA Renewable Cost Database.*

## BIOENERGY FOR POWER

Power generation from bioenergy can come from a wide range of feedstocks. It can also use a variety of different combustion technologies, running from mature, commercially available varieties with long track records and a wide range of suppliers, to less mature but innovative systems. The latter category includes atmospheric biomass gasification and pyrolysis, technologies that are still largely at the developmental stage but are now being tried out on a commercial scale. Mature technologies include: direct combustion in stoker boilers; low-percentage co-firing; anaerobic digestion; municipal solid waste incineration; landfill gas; and combined heat and power (CHP).

In order to analyse the use of biomass power generation, it is important to consider three main factors: feedstock type and supply; the conversion process; and the power generation technology. Although the availability of feedstock is one of the main elements for the economic success of biomass projects, this report's analysis focuses on the costs of power generation technologies and their economics, while only briefly discussing delivered feedstock costs.

## BIOMASS FEEDSTOCKS

The economics of biomass power generation is different from that of wind, solar or hydro. This is because biomass is dependent upon the availability of a feedstock supply that is predictable, sustainably sourced, low-cost and adequate over the long term.

An added complication is that there is a range of cases where electricity generation is not the primary activity of site operations. Instead, a site is tied to forestry or agricultural processing activities that may impact when and why electricity generation happens. For instance, with electricity generation at pulp and paper mills, a significant proportion of the electricity generated will be used to run these facilities' operations.

Biomass is the organic material of recently living plants, such as trees, grasses and agricultural crops. Biomass feedstocks are thus very heterogeneous, with the chemical composition highly dependent on the plant species.

The cost of feedstock per unit of energy is highly variable, too. This is because the feedstock can range from onsite processing residues that would otherwise cost money to dispose of, to dedicated energy crops that must pay for the land used, the harvesting and logistics of delivery, and storage on site at a dedicated bioenergy power plant.

Examples of low-cost residues that are combusted for electricity and heat generation include: sugarcane bagasse, rice husks, black liquor and other pulp and paper processing residues, sawmill offcuts and sawdust, and renewable municipal waste streams.

In addition to cost, the physical properties of the feedstocks matter, as they will differ in ash content, density, particle size and moisture, with heterogeneity in quality. These factors also have an impact on the transportation, pre-treatment and storage costs, as well as the appropriateness of different conversion technologies. Some of these are relatively robust and can cope with heterogeneous feedstocks, while others require more uniformity (*e.g.,* some gasification processes).

A key cost consideration for bioenergy is that most forms have relatively low energy density. Collection and transport costs often therefore dominate the costs of feedstocks derived from forest residues and dedicated energy crops. A consequence of this is that logistical costs start to increase significantly, the further from the power plant the feedstocks need to be sourced. In practical terms, this tends to limit the economic size of bioenergy powerplants, as the lowest cost of electricity is achieved once feedstock delivery reaches a certain radius around the plant.

For biomass technologies, the typical share of the feedstock cost in the total LCOE ranges between 20% and 50%. Prices for biomass sourced and consumed locally, however, are difficult to obtain. This means that whatever market indicators for feedstock costs are available must be used as proxies. Alternatively, estimates of feedstock costs from techno-economic analyses that may not necessarily be representative or up-to-date can be used (see IRENA, 2015, for a more detailed discussion of feedstock costs).

## TOTAL INSTALLED COSTS

Different regions have differing costs in biomass power generation, with both a technology component and a local cost component in total cost.

Projects in emerging economies tend to have lower investment costs when compared to projects in the OECD countries. This is because emerging economies often benefit from lower labour and commodity costs. This allows the deployment of lower cost technologies with reduced emission control investments, albeit with higher local pollutant emissions, in some cases.

The main categories in the total investment costs of a biomass power plant are: planning, engineering and construction costs; fuel handling and preparation machinery; and other equipment (*e.g.,* the prime mover and fuel conversion system). Additional costs are derived from grid connection and infrastructure (*e.g.,* civil works and roads).

Equipment costs tend to dominate, but specific projects can have high costs for infrastructure and logistics, or for grid connection when located in remote areas. CHP biomass installations have higher capital costs. Yet, their higher overall efficiency (around 80% to 85%) and their ability to produce heat and/or steam for industrial processes – or for space and water heating through district heating networks – can significantly improve their economics.

Figure 8.2 presents the total installed cost of bioenergy-fired power generation projects for different feedstocks for the years 2000 to 2020, where IRENA has sufficient data to provide meaningful cost ranges.

Although the pattern of deployment by feedstock varies by country and region, it is clear that total installed costs across feedstocks tend to be higher in Europe and North America and lower in Asia and South America. This often reflects the fact that bioenergy projects in OECD countries are often based on wood, or are combusting renewable municipal or industrial waste, where the main activity may be waste management. In these instances, energy generation (potentially heat and electricity) is a by-product of the fact that CHP has been found to be the cheapest way to manage waste.

For the 2000 to 2020 period, in China, the 5$^{th}$ and 95$^{th}$ percentile of projects across all feedstocks saw total installed costs range from a low of USD 634/kW for rice husk projects to a high of USD 5 304/kW for renewable municipal waste projects. In India, the range was from a low of USD 514/kW for bagasse projects to a high of USD 4 356/kW for landfill gas projects.

The range is higher for projects in Europe and North America. Costs in these two geographies ranged from USD 598/kW for landfill gas projects in North America, to a high of USD 7 940/kW for wood waste projects in Europe, during the period in question. This was because in these regions, the technological options used to develop projects are more heterogeneous and on average more expensive.

The data available by feedstock for the rest of the world were more limited, but the 5$^{th}$ and 95$^{th}$ percentile total installed cost range for wood waste projects was the widest. For these, the data stretched from USD 581/kW to USD 4 958/kW.[1] The weighted average total installed cost for projects in the rest of the world typically lay between the lower values seen in China and India and the higher values prevalent in Europe and North America, for the time period covered.

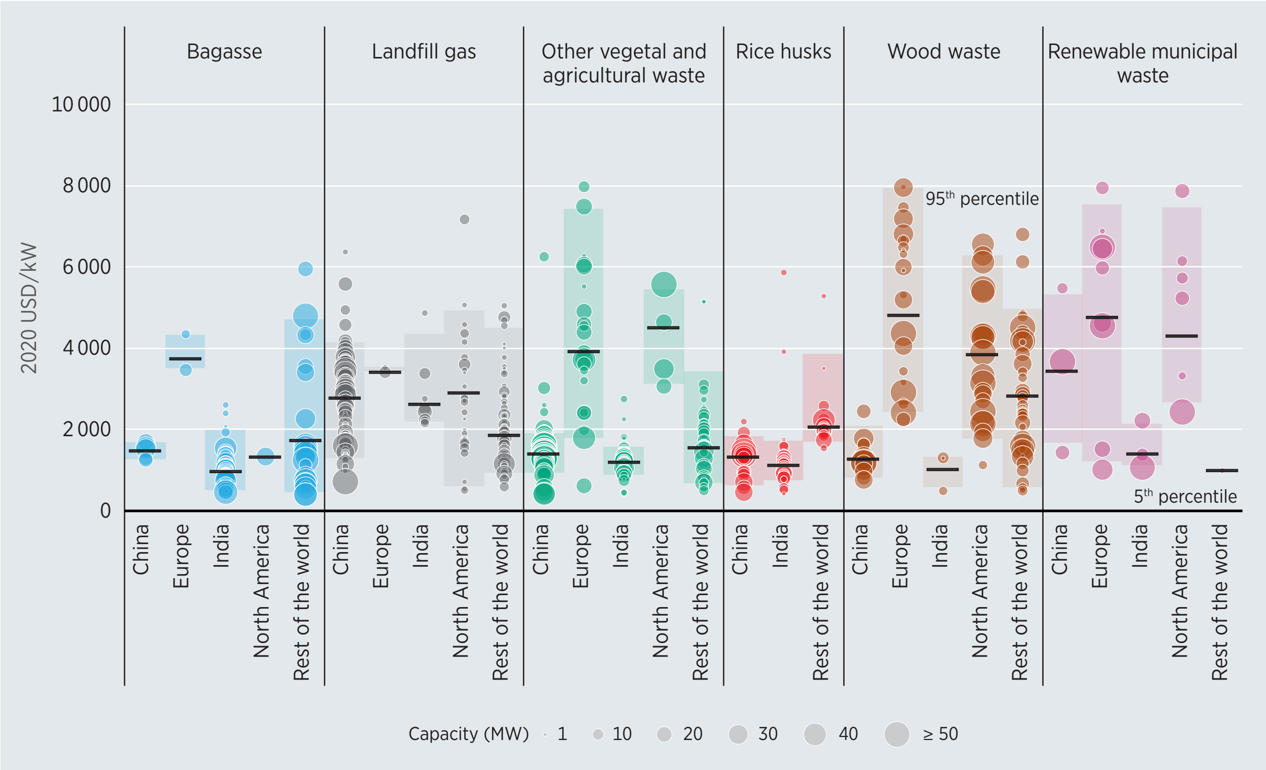
*There are clear economies of scale for bioenergy projects in China and India for projects above 25 MW*

Figure 8.3 presents the total installed cost by project, based on capacity ranges. It shows that in the power sector, bioenergy projects are predominantly small scale, with the majority of projects under 25 MW in capacity. There are, however, clear economies of scale evident for plants roughly above the 25 MW level, at least in the data for China and India.

The relatively small size of bioenergy for electricity plants is the result of the low energy density of bioenergy feedstocks and the increasing logistical costs involved in enlarging the collection area to provide a greater volume of feedstock to support large-scale plants. The optimal size of a plant to minimise the LCOE of a project, in this context, is a trade-off between the cost benefits of economies of scale and the higher feedstock costs – which grow as the average distance to the plant of the sourced feedstocks expands.

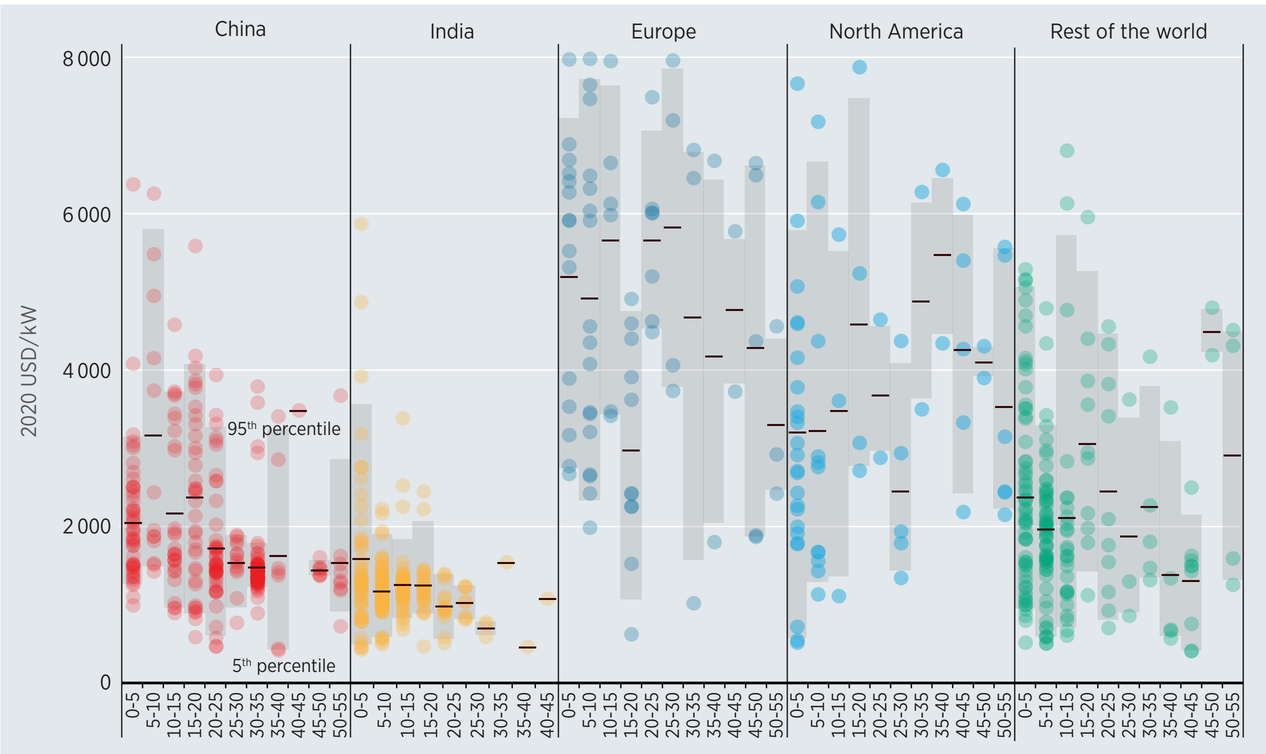
1 *Excluding the total installed costs for renewable municipal waste, which are not representative given that there are only two projects in the database.*

**Figure 8.2** Total installed costs of bioenergy power generation projects by selected feedstocks and country/region, 2010-2020




*Source: IRENA Renewable Cost Database.*

**Figure 8.3** Total installed costs of bioenergy power generation projects for different capacity ranges by country/region, 2010-2020




*Source: IRENA Renewable Cost Database.*

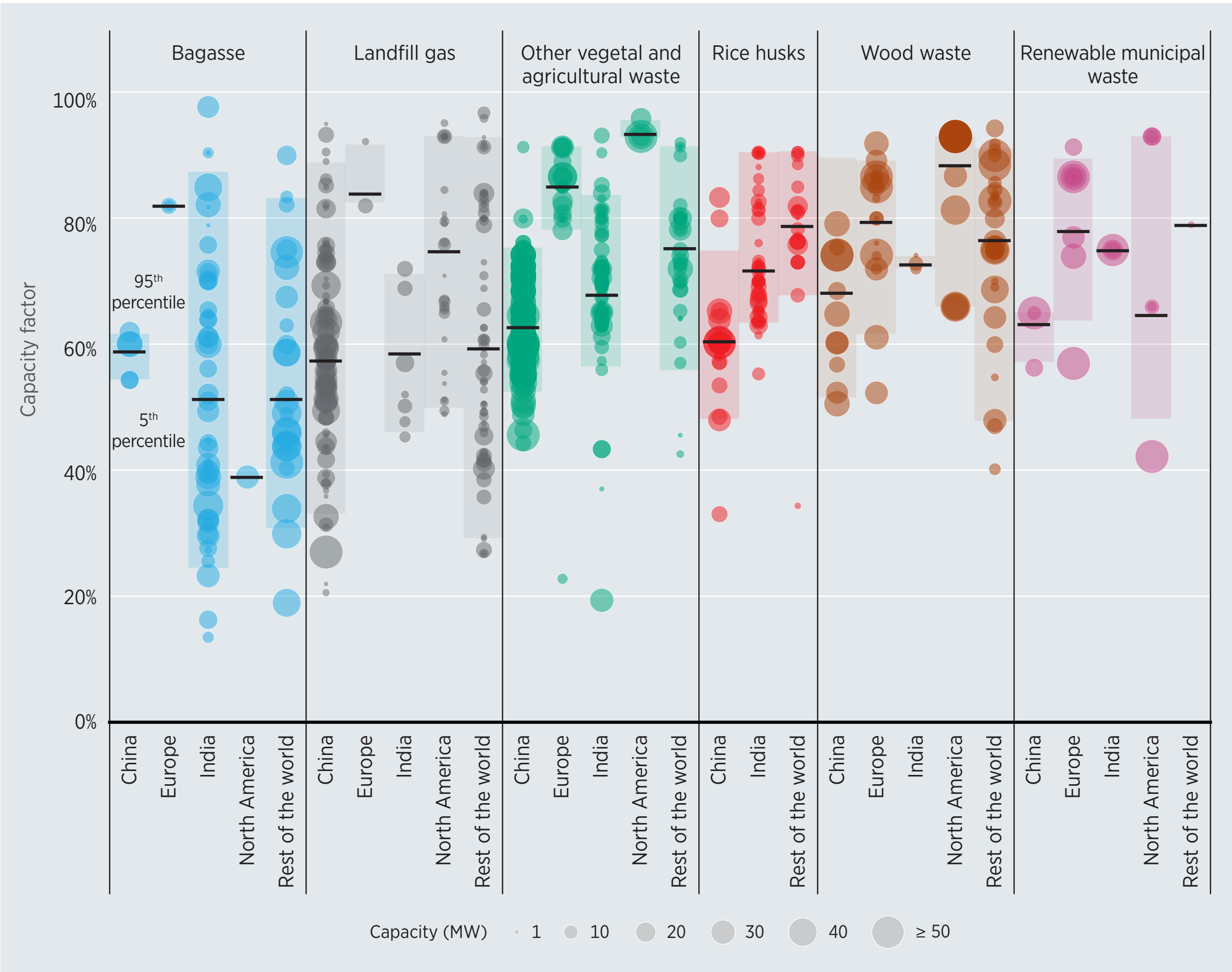
## CAPACITY FACTORS AND EFFICIENCY

When feedstock availability is uniform over the entire year, bioenergy-fired electricity plants can have very high capacity factors, ranging between 85% and 95%. When the availability of feedstock is based on seasonal agricultural harvests, however, capacity factors are typically lower.

An emerging issue for bioenergy power plants is the impact climate change may have on feedstock availability and how this might effect the total annual volume available, as well as its distribution throughout the year. This is an area where the need for research will be ongoing, as the climate changes.

Figure 8.4 shows that biomass plants that rely on bagasse, landfill gas and other biogases tend to have lower capacity factors (around 50% to 60%). Plants relying on wood, fuel wood, rice husks, and other vegetal and agricultural, industrial and renewable municipal waste, however, tend to have weighted-average capacity factors by region in the range of 60% to 93%.

**Figure 8.4** Project capacity factors and weighted averages of selected feedstocks for bioenergy power generation projects by country and region, 2010-2020




*Source: IRENA Renewable Cost Database.*

After accounting for feedstock handling, the assumed net electrical efficiency of the prime mover (the generator) averages around 30%. This does, however, vary from a low of 25% to a high of around 36%. CHP plants that produce heat and electricity achieve higher efficiencies, with an overall level of 80% to 85% not uncommon.

In developing countries, less advanced technologies – and sometimes suboptimal maintenance when revenues are less than anticipated – result in lower overall efficiencies. These can be around 25%, but many technologies are available with higher efficiencies. The latter can range from 31% for wood gasifiers to a high of 36% for modern, well-maintained stoker, circulating fluidised bed (CFB), bubbling fluidised bed (BFB) and anaerobic digestion systems (Mott MacDonald, 2011). These assumptions are unchanged from the last two IRENA cost reports (IRENA, 2018 and 2019).

Table 8.1 presents data for project weighted-average capacity factors of bioenergy-fired power generation projects for the period 2000 to 2020. According to the IRENA cost database, North America showed the highest weighted-average capacity factor – 85% – followed by Europe, with 82%, India with 68%. China and the rest of the world showed lower weighted-average capacity factors of 64% and 67%, respectively.

**Table 8.1** Project weighted-average capacity factors of bioenergy-fired power generation projects, 2010-2020

| | 2000-2020 | | |
|---|---|---|---|
| | 5th percentile (%) | Weighted average (%) | 95th percentile (%) |
| **China** | 39 | **64** | 82 |
| **Europe** | 48 | **82** | 92 |
| **India** | 32 | **68** | 87 |
| **North America** | 39 | **85** | 94 |
| **Rest of the world** | 34 | **67** | 92 |

*Source: IRENA Renewable Cost Database.*

## OPERATION AND MAINTENANCE COSTS

Fixed operation and maintenance (O&M) costs include: labour, insurance, scheduled maintenance and routine replacement of plant components (*e.g.,* boilers and gasifiers), feedstock handling equipment, and other items. In total, these O&M costs account for between 2% and 6% of the total installed costs per year. Large bioenergy power plants tend to have lower per-kW fixed O&M costs, due to economies of scale.

Variable O&M costs, at an average of USD 0.005/kWh, are usually low for bioenergy power plants, when compared to fixed O&M costs. Replacement parts and incremental servicing costs are the main components of variable O&M costs, although these also include non-biomass fuel costs, such as ash disposal. Due to its project-specific nature and the limited availability of data, in this report, variable O&M costs have been merged with fixed O&M costs.

## LEVELISED COST OF ELECTRICITY

The wide range of bioenergy-fired power generation technologies, installed costs, capacity factors and feedstock costs results in a wide range of observed LCOEs for bioenergy-fired electricity.

Figure 8.5 summarises the estimated LCOE range for biomass power generation technologies by feedstock and country/region, where the IRENA Renewable Cost Database has sufficient data to provide meaningful insights.

Assuming a cost of capital of between 7.5% and 10% and feedstock costs between USD 1/Gigajoule (GJ) and USD 9/GJ (the LCOE calculations in this report are based on an average of USD 1.50/GJ), the global weighted-average LCOE of biomass-fired electricity generation for projects commissioned in 2020 was USD 0.076/kWh. This was an increase from USD 0.066/kWh in 2019 and the same value as in 2010.

Looking at the full dataset for the period from 2000 to 2020, the lowest weighted-average LCOE of biomass-fired electricity generation was found in India, where it stood at USD 0.057/kWh. In addition, India's $5^{th}$ and $95^{th}$ percentile values were USD 0.040/kWh and USD 0.098/kWh (Figure 8.5). The highest weighted-average for this period was the USD 0.097/kWh recorded in North America, where the $5^{th}$ and $95^{th}$ percentiles of projects fell between USD 0.048/kWh and USD 0.173/kWh.

The weighted average LCOE of bioenergy projects in China was USD 0.060/kWh, with the $5^{th}$ and $95^{th}$ percentiles of projects falling between USD 0.045/kWh and USD 0.115/kWh. The weighted average in Europe over this period was USD 0.088/kWh, while in the rest of the world it was USD 0.070/kWh.

Bioenergy can provide very competitive electricity where capital costs are relatively low and low-cost feedstocks are available. Indeed, this technology can provide dispatchable electricity generation with an LCOE as low as around USD 0.04/kWh.

The most competitive projects make use of agricultural or forestry residues already available at industrial processing sites, where marginal feedstock costs are minimal, or even zero. Where onsite, industrial process steam or heat loads are required, bioenergy CHP systems can also reduce the LCOE for electricity to as little as USD 0.03/kWh, depending on the alternative costs for heat or steam available to the site.[2] Even higher cost projects in certain developing countries can be attractive, however, because they provide security of supply in conditions where brownouts and blackouts can be particularly problematic for the efficiency of industrial processes.

*2 This is an area of weakness of the data available to IRENA, as in many cases the details of any onsite heat use or sales is not readily available. Future work by IRENA will focus on research that will try and collect this information for a greater number of projects. Until that time, these LCOE values should be consider upper ranges, as an increased heat credit would materially reduce weighted-average LCOE values.*

Projects using low-cost feedstocks such as agricultural or forestry residues, or the residues from processing agricultural or forestry products, tend to have the lowest LCOEs. For projects in the IRENA Renewable Cost Database, the weighted average project LCOE by feedstock is USD 0.06/kWh or less for those using black liquor, primary solid bioenergy (typically wood or wood chips), renewable municipal solid waste and other vegetal and agricultural waste.

Projects relying on municipal waste come with high capacity factors and are generally an economic source of electricity. Yet, the LCOE for projects in North America is significantly higher than the average. Given that these projects have been developed mostly to solve waste management issues, though, and not primarily for the competitiveness of their electricity production, this is not necessarily an impediment to their viability.

In Europe, such projects also sometimes supply heat either to local industrial users, or district heating networks, with the revenues from these sales bringing the LCOE below that presented here. Many of the higher cost projects in Europe and North America using municipal solid waste as a feedstock rely on technologies with higher capital costs, as more expensive technologies are used to ensure local pollutant emissions are reduced to acceptable levels. Excluding these projects – which are typically not the largest – reduces the weighted average LCOE in Europe and North America by around USD 0.01/kWh and narrows the gap with the LCOE of non OECD regions.

**Figure 8.5** LCOE by project and weighted averages of bioenergy power generation projects by feedstock and country/region, 2010-2020

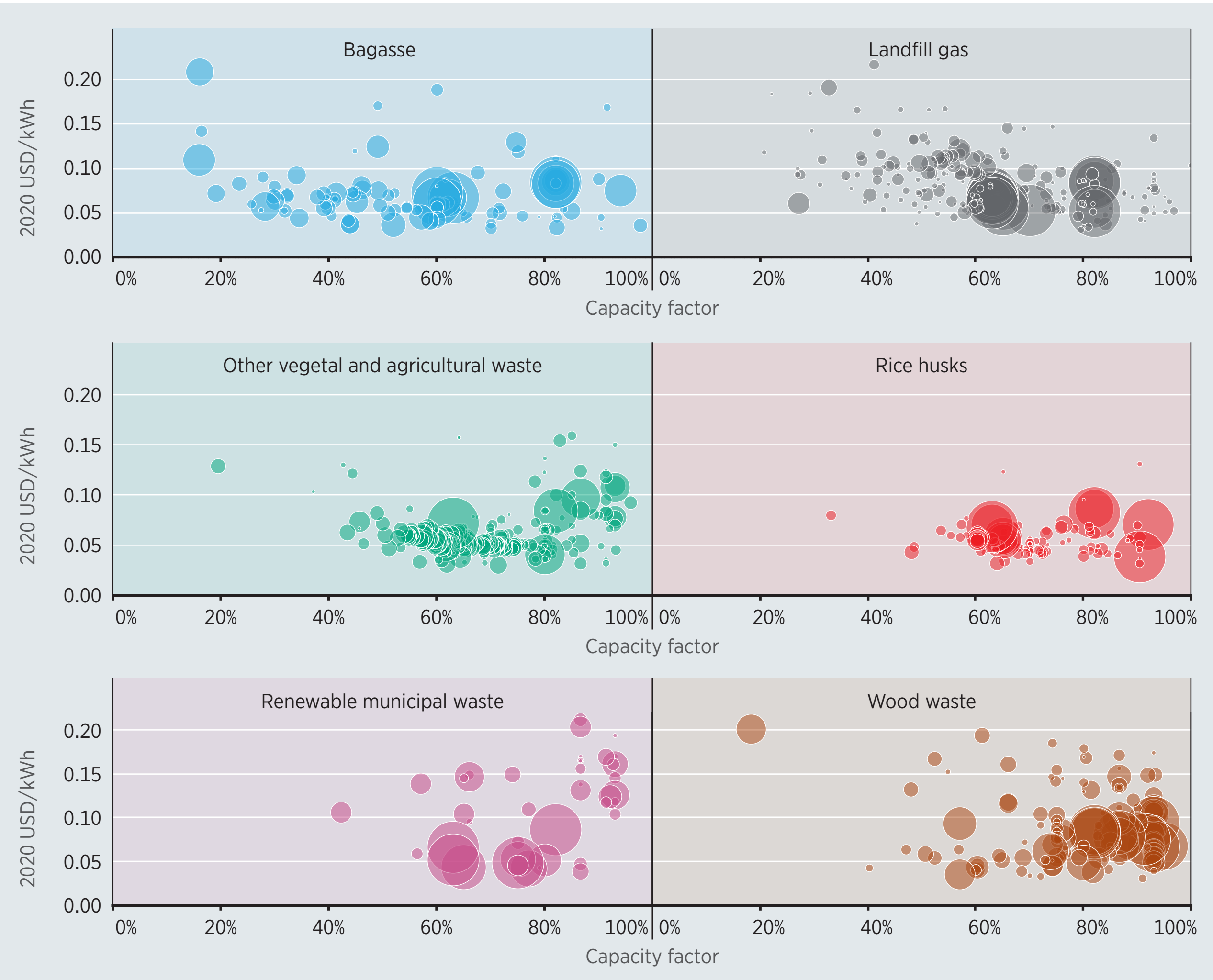

*Source: IRENA Renewable Cost Database.*

Figure 8.6 presents the LCOE and capacity factor by project and weighted averages for bagasse, landfill gas, rice husks and other vegetal and agricultural waste, in addition to renewable municipal waste and wood waste used as feedstock for bioenergy-fired power generation projects. The figure shows how the dynamic relationship between feedstock availability influences the economic optimum for a project. The data for bagasse plants shows this clearly. Where the capacity factor is more than 30%, there is no strong relation between the capacity factor and the LCOE of the project.

This indicates that the availability of a continuous stream of feedstock allows for higher capacity factors, but is not necessarily more economic, if it means that low-cost seasonal agricultural residues need to be supplemented by more expensive feedstocks. Importantly, the LCOE of these projects is comparable to projects relying on more generic, woody biomass feedstocks, such as wood pellets and chips, which can be more readily purchased, year round.

Thus, access to low cost feedstock offsets the impact on LCOE of lower capacity factors. For projects using other vegetal and agricultural wastes as the primary feedstock, the data tends to suggest that there is a correlation between higher capacity factors and lower LCOEs in developing countries, given that the higher cost projects with capacity factors above 80% are all located in OECD countries.

**Figure 8.6** LCOE and capacity factor by project of selected feedstocks for bioenergy power generation projects, 2010-2020




*Source: IRENA Renewable Cost Database.*

# 09

# RENEWABLE HEAT COSTS

## COMMERCIAL AND INDUSTRIAL SOLAR THERMAL

Solar thermal technologies are used in all regions of the world to provide low and medium temperature heat in industry and buildings.

Solar thermal technologies are highly modular and can be installed on the rooftops of individual buildings for residential use, or in hospitals or hotels. They can also be found in large, MW-scale ground-mounted systems in industry, agriculture and district heating networks.

The market for solar thermal is still at an early stage of development, but at least 120 large-scale heat projects were added in 2020 in the commercial and industrial sectors. These feed renewable heat into district heating networks, or supply heat to processes in the manufacturing sector. Compared to what is needed to achieve the Paris Agreement goals, deployment rates remain woefully inadequate. For instance, IRENA's 1.5°C pathway requires global solar thermal capacity to increase from around 4 gigawatts thermal ($GW_{th}$) in 2018 to 890 $GW_{th}$ in 2030 and 1290 $GW_{th}$ in 2050.

Modest growth – total solar thermal heat capacity in Europe grew by only 3% in 2020 (Solar Heat Europe/ESTIF, 2021) – is therefore insufficient. Like many of the technologies necessary for decarbonising the building and industrial sectors, solar thermal is typically held back by the absence of co-ordinated and sustained policy support to decarbonise heat. The result of erratic and inconsistent support levels over time, has been insufficient market growth and the subsequent lack of scale that would otherwise stem from more consistent policy support and allow lower costs.

Solar thermal has also been held back by a lack of transparency regarding the cost and performance of systems and their potential for cost reduction. This raises information costs, introduces uncertainty and deters investors and policy makers from seriously investigating the opportunity that solar thermal represents in contributing to a 1.5°C pathway.

To fill this gap with accurate, timely, verifiable cost and performance data for solar heat technologies, IRENA has partnered with the Solar Payback to survey industry participants. The data collection process targeted the largest 32 project developers and technology suppliers for solar heat worldwide, as well as funding agencies in Europe.

The project has been successful in collecting comprehensive cost and performance data for large[1] solar thermal heat projects that have been commissioned in roughly the last 10 years. The database currently contains data for over 1 750 commercial and industrial solar heat projects, totalling 935 megawatts thermal ($MW_{th}$). The database contains 115 district heating projects, totalling 686 $MW_{th}$, 259 solar heat for industrial processes (SHIP) projects totaling 92 $MW_{th}$, with the remaining projects covering space heating and hot water.

The data come from 24 different countries, but the majority are from the major markets for commercial and industrial solar heat projects: Austria, China, Denmark, France, Germany, India, Mexico, Spain and the United States.

In terms of collector technology, flat plate collectors represent 1 570 projects, totalling 776 $MW_{th}$, with 93 projects and 103 $MW_{th}$ using concentrating collectors and 104 projects and 54 $MW_{th}$ using vacuum tube collectors. To the best of the project partners' knowledge, this is the most comprehensive database of the cost and performance characteristics of large-scale solar thermal heat projects in existence.

The following section highlights some of the early findings from the data collection process. The full dataset will be presented and analysed in a forthcoming report by IRENA and Solar Payback in 2021. Next years Renewable Power Generation Cost report will include a more detailed discussion than presented here based on the full database, updated to include data for 2021 where possible.

## SOLAR THERMAL FOR DISTRICT HEATING IN DENMARK

Denmark leads the world for total district heating capacity in operation, with more than 1 $GW_{th}$ at the end of 2020. Around 120 villages, towns and cities use solar heat in their municipality-owned district heating networks.

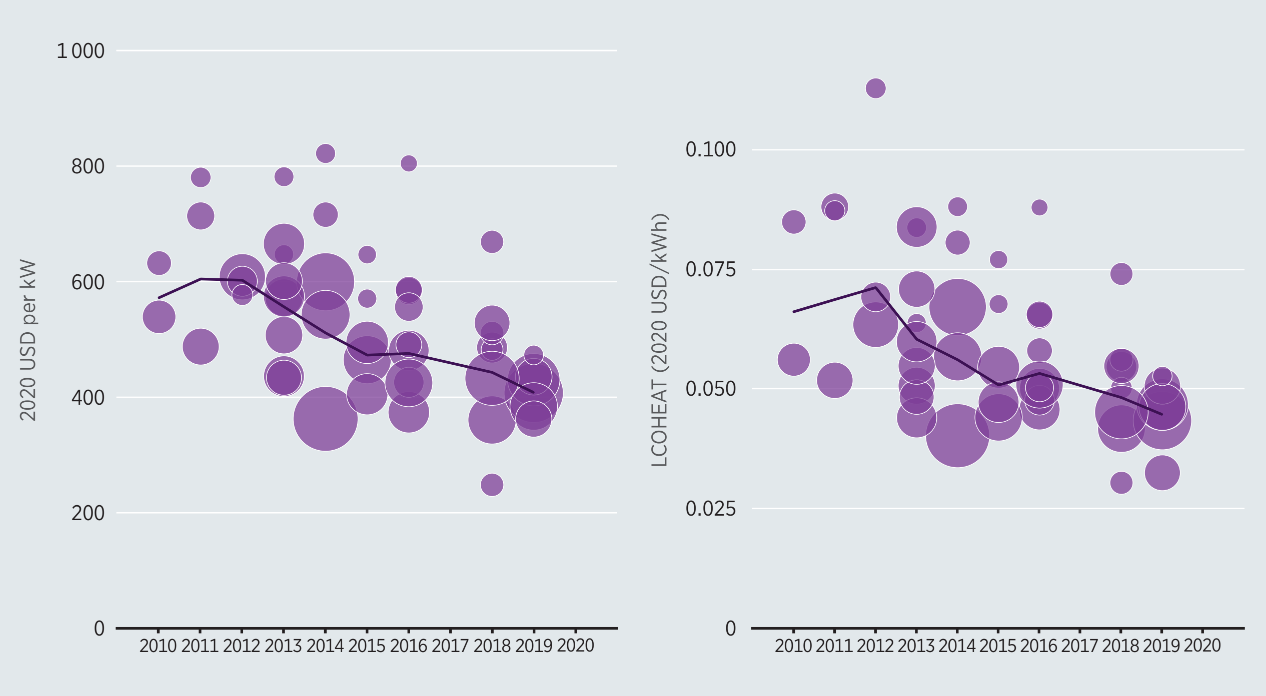
The total installed cost of district heating scale solar heat in Denmark fell from a weighted average of USD 573/kW in 2010 to USD 409/kW in 2019. This represents a learning rate for the period of around 17% – slightly higher than that of onshore wind for the period 2010 to 2020. These cost reductions have made solar thermal heating systems a competitive source of heat for district heating, as the weighted-average levelised cost of heat (LCOHEAT) fell from USD 0.066/kWh in 2010 to USD 0.045/kWh in 2019 (Figure 9.1).

In the first years of this period, prices were fairly stable. Then, there was a steep decline of LCOHEAT after 2014, driven by an increasingly competitive supply chain and growing developer experience amongst a small number of highly competitive project developers. Economies of scale are also evident in the most recent years.

The figure excludes a 110 $MW_{th}$ project commissioned in 2016, as this project has lower costs and is something of an outlier in the database. Including this project in the chart would increase the learning rate to 19%. The other important point to note is that since 2016, 55% of the projects commissioned have included storage tanks to meet demand throughout the entire day.

*1 Given the nascent nature of the market for these systems, the threshold is set as low as 50 square metres ($m^2$) of collector area for solar industrial heat systems. This is in order to collect as much relevant data as possible, particularly in Europe, where support schemes for these systems are an important source of data.*

**Figure 9.1** Total installed costs and LCOHEAT for solar thermal district heating plants in Denmark, 2010-2019




*Source: IRENA and Solar Payback, 2021.*
*Note: Data is for 50 projects commissioned between 2010 and 2019 ranging in size from 1.8 $MW_{th}$ to 26 $MW_{th}$.*

## LARGE-SCALE SOLAR THERMAL IN AUSTRIA, GERMANY AND MEXICO

Figure 9.2 presents the data for all of the large-scale solar thermal heat projects in the database for Austria, Germany and Mexico. The data for Austria (89 projects) are a mix of all applications for which data was collected, including central space heating and hot water systems, process heat (air, liquid and steam), as well as for district heating systems.

The data for Germany (209 projects) are predominantly for central hot water and space heating systems, but also include a number of district heating systems and process heat (air or liquid) systems. Mexico (108 projects) is somewhat different, with most of the large systems there being for process heat (liquid or process heat (steam), with some data for large central hot water systems. The data for Austria has a gap in 2019, for which data from the support scheme were not available.

*In Austria, total installed costs fell by 55% between 2013 and 2020. In Germany, they fell by 45% between 2014 and 2020*

**Figure 9.2** Total installed costs and LCOHEAT for commercial and industrial-scale solar thermal plants in Austria, Germany and Mexico, 2010-2020


*Source: IRENA and Solar Payback, 2021.*

In Austria, total installed costs fell by 55% between 2013 and 2020. In Germany, they fell by 45% between 2014 and 2020, while in Mexico, they fell by 17% between 2010 and 2020. Data for 2020 and 2021 is still sparse, while care must be taken interpreting the data – notably for Austria, where only a handful of data points is available. By 2020, however, total installed costs had converged somewhat, with, on average, larger projects in Austria having a slightly lower weighted average in those two years than in Germany and Mexico. When we come to LCOHEAT, however, the superior solar resources available in Mexico become readily apparent, as the weighted-average LCOHEAT of the solar thermal plants in Mexico in 2020 was USD 0.039/kWh. The increase in Germany in 2020 for LCOHEAT is due to one outlier, with very high installed costs, while the decline for Austria in the weighted-average LCOHEAT between 2018 and 2020 is predominantly due to the much larger average size of systems deployed in the latter period, compared to the period prior to 2018. This is a graphic illustration of the benefits of economies of scale.

## ECONOMIES OF SCALE

Despite the small-scale of the market for solar thermal in Europe, the data for district heating projects in Europe helps to show the impact that economies of scale can have on project costs.

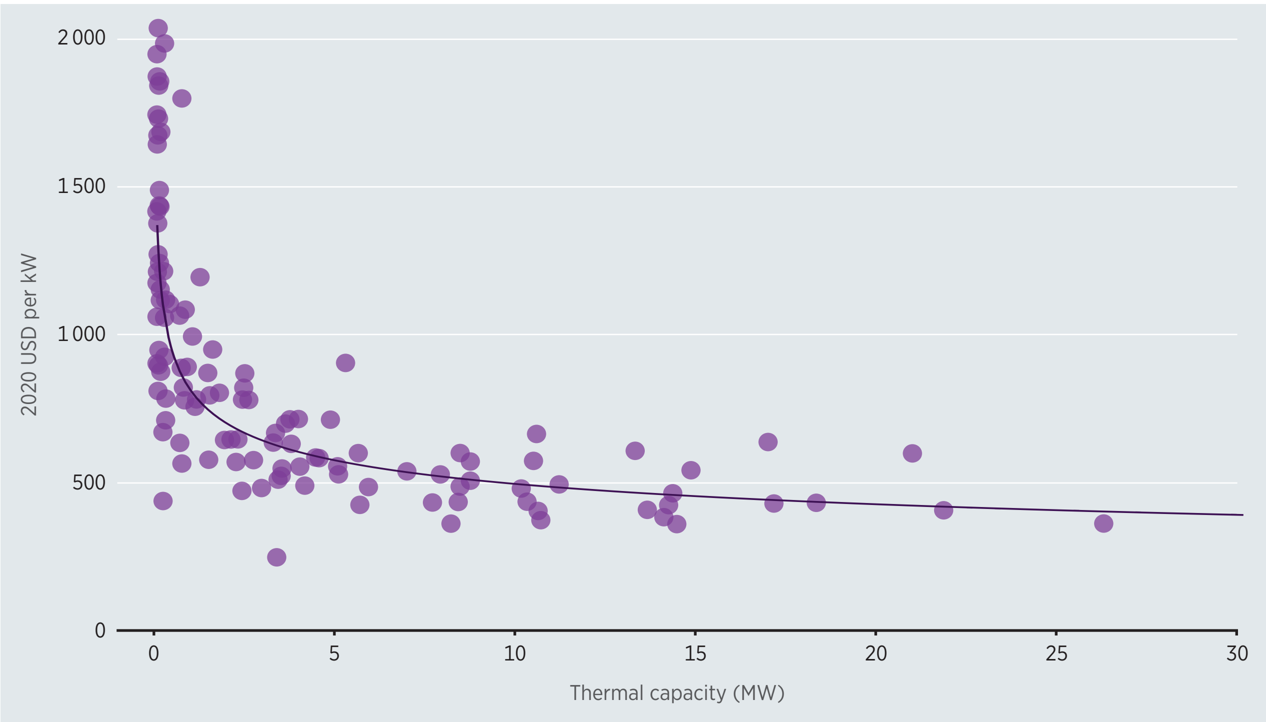
The Danish district heating market has been marked by experienced suppliers and manufacturers, competing to deliver competitive MW-scale projects to district heating schemes. Between 2010 and 2020, the weighted-average project size for those in our database ranged from a low of 5.4 $MW_{th}$ in 2010 to a high of 17 $MW_{th}$ in 2016 and was 12 $MW_{th}$ in 2019. For Europe, these are large project sizes and as can be seen from Figures 9.1 and 9.2, the result is that Denmark has a very competitive LCOHEAT.

Costs are higher in Austria and Germany and this is directly related to project size, although other factors no doubt also play a role. In Austria, the weighted-average size of district heating projects ranged from a low of 0.1 $MW_{th}$ in 2012 to a high of 0.4 $MW_{th}$ in 2017. Germany's district heating schemes sit in between Austria and Denmark, ranging from a low of 0.8 MW in 2017 to a high of 2.1 $MW_{th}$ achieved in the previous year, 2016.

Figure 9.3 shows the total installed cost data for 118 district heating projects, plotted against the project capacity in MW. Austria, Denmark and Germany account for 97% of the district heating projects in the database, and the clear economies of scale in project size are quite evident. Austrian district heating projects lie almost exclusively in the range up to 1 $MW_{th}$, while most German projects are situated between 0.4 $MW_{th}$ and 1.9 $MW_{th}$. Denmark dominates the far right of the figure, with most projects in the 2 $MW_{th}$ to 15 $MW_{th}$ range. Not shown on the chart is the 110 $MW_{th}$ plant from Denmark, but it is included for the calculation of the trend line. The fitted line for economies of scale suggests that for every doubling in the size of the plant, total installed costs will decline by 14%.

Policies to support larger-scale projects would likely have immediate benefits for consumers in terms of lower renewable heat costs in most of Europe, as the example of Denmark demonstrates. This is before considering the benefits to economies of scale in manufacturing that would occur if a more ambitious programme of support for renewable heat was pursued.

**Figure 9.3** Total installed costs for district heating projects by installed capacity in Europe, 2010-2020




*Source: IRENA and Solar Payback, 2021*

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# ANNEX I
## COST METRIC METHODOLOGY

Cost can be measured in different ways, with different cost metrics bringing their own insights. The costs that can be examined include equipment costs (*e.g.,* photovoltaic modules or wind turbines), financing costs, total installed costs, fixed and variable operating and maintenance costs (O&M), fuel costs (if any), and the levelised cost of electricity (LCOE).

The analysis of costs can be very detailed, but for comparison purposes and transparency, the approach used here is a simplified one that focusses on the core cost metrics for which good data are readily available. This allows greater scrutiny of the underlying data and assumptions, improves transparency and confidence in the analysis, while facilitating the comparison of costs by country or region for the same technologies, enabling the identification of the key drivers in any cost differences.

The five key indicators that have been selected are:

- equipment cost (factory gate, free onboard [FOB], and delivered at site)
- total installed project cost, including fixed financing costs
- capacity factor by project
- the LCOE.

The analysis in this paper focuses on estimating the costs of renewables from the perspective of private investors, whether they are a state-owned electricity generation utility, an independent power producer (IPP), or an individual or community looking to invest in small-scale renewables. The analysis excludes the impact of government incentives or subsidies, system balancing costs associated with variable renewables and any system-wide cost-savings from the merit order effect. Furthermore, the analysis does not take into account any $CO_2$ pricing or the benefits of renewables in reducing other externalities (*e.g.,* reduced local air pollution or contamination of the natural environment). Similarly, the benefits of renewables being insulated from volatile fossil fuel prices have not been quantified. These issues are important but are covered by other programmes of work at IRENA.

Clear definitions of the technology categories are provided, where this is relevant, to ensure that cost comparisons are robust and provide useful insights (*e.g.,* small hydropower vs. large hydropower). Similarly, functionality has to be distinguished from other qualities of the renewable power generation technologies being investigated (*e.g.,* concentrating solar power [CSP] with and without thermal energy storage). This is important to ensure that system boundaries for costs are clearly set and that the available data are directly comparable. Other issues can also be important, such as cost allocation rules for combined heat and power plants, and grid connection costs.

The data used for the comparisons in this paper come from a variety of sources, such as IRENA Renewable Costing Alliance members, business journals, industry associations, consultancies, governments, auctions and tenders. Every effort has been made to ensure that these data are directly comparable and are for the same system boundaries. Where this is not the case, the data have been corrected to a common basis using the best available data or assumptions. These data have been compiled into a single repository – the IRENA Renewable Cost Database – that includes a mix of confidential and public domain data.

An important point is that, although this report examines costs, strictly speaking, the data points available are actually prices – which are sometimes not even true market average prices, but price indicators (*e.g.,* surveyed estimates of average module selling prices in different markets).

The difference between costs and prices is determined by the amount above, or below, the normal profit that would be seen in a competitive market.

The rapid growth of renewables markets from a small base means that the market for renewable power generation technologies is sometimes not well balanced. As a result, prices can rise significantly above costs in the short term if supply is not expanding as fast as demand, while in times of excess supply, losses can occur, and prices may be below production costs. This can make analysing the cost of renewable power generation technologies challenging for some technologies in given markets at certain times. Where costs are significantly above or below where they might be expected to be in their long-term trend, every effort has been made to identify the causes.

Although every effort has been made to identify the reasons why costs differ between markets for individual technologies, the absence of the detailed data required for this type of analysis often precludes a definitive answer. IRENA conducted a number of analyses focusing on individual technologies and markets in an effort to fill this gap (IRENA, 2016a and 2016b).

The LCOE of renewable energy technologies varies by technology, country and project, based on the renewable energy resource, capital and operating costs, and the efficiency/performance of the technology. The approach used in the analysis presented here is based on a discounted cash flow (DCF) analysis. This method of calculating the cost of renewable energy technologies is based on discounting financial flows (annual, quarterly or monthly) to a common basis, taking into consideration the time value of money. Given the capital-intensive nature of most renewable power generation technologies and the fact that fuel costs are low, or often zero, the weighted average cost of capital (WACC) used to evaluate the project – often also referred to as the discount rate – has a critical impact on the LCOE.

There are many potential trade-offs to be considered when developing an LCOE modelling approach. The approach taken here is relatively simplistic, given the fact that the model needs to be applied to a wide range of technologies in different countries and regions. This has the advantage, however, of producing a transparent and easy-to-understand analysis. In addition, more detailed LCOE analyses result in a significantly higher overhead in terms of the granularity of assumptions required. This can give the impression of greater accuracy, but when the model cannot be robustly populated with assumptions, and if assumptions are not differentiated based on real-world data, then the accuracy of the approach can be misleading.

The formula used for calculating the LCOE of renewable energy technologies is:

$$\mathrm{LCOE} = \frac{\sum_{t=1}^{n} \frac{I_t + M_t + F_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{E_t}{(1+r)^t}}$$

Where:
LCOE = the average lifetime levelised cost of electricity generation
$I_t$ = investment expenditures in the year $t$
$M_t$ = operations and maintenance expenditures in the year $t$
$F_t$ = fuel expenditures in the year $t$
$E_t$ = electricity generation in the year $t$
$r$ = discount rate
$n$ = life of the system.

All costs presented in this report are denominated in real, 2020 US dollars; that is to say, after inflation has been taken into account, unless otherwise stated. The LCOE is the price of electricity required for a project where revenues would equal costs, including making a return on the capital invested equal to the discount rate. An electricity price above this would yield a greater return on capital, while a price below it would yield a lower return on capital, or even a loss. The same formula is used for calculating the levelised cost of heat, assuming a WACC of 5%, a 25 year economic life and O&M costs of 0.5% of total installed costs for plants with more than 700 kW of capacity and 1% for those below.

As already mentioned, although different cost measures are useful in different situations, the LCOE of renewable energy technologies is a widely used first order measure by which power generation technologies can be compared. More detailed DCF approaches – taking into account taxation, subsidies and other incentives – are used by renewable energy project developers to assess the profitability of real-world projects but are beyond the scope of this report.

The calculation of LCOE values in this report is based on project-specific total installed costs and capacity factors, as well as the O&M costs. The data for project specific-total installed costs for the most recent years is a mix of *ex ante* and *ex post* data. The data for project-specific capacity factors for, in virtually all cases, the last two years *ex ante* data and subject to change.

Though the terms "O&M" and "OPEX" (operational expenses) are often used interchangeably. The LCOE calculations in this report are based on "all-in-OPEX", a metric that accounts for all operational expenses of the project including some that are often excluded from quoted O&M price indices, such as insurance and asset management costs. Operational expense data for renewable energy projects are often available with diverse scope and boundary conditions.

These data can be difficult to interpret and harmonise depending on how transparent and clear the source is around the boundary conditions for the O&M costs quoted. However, every effort has been made to ensure comparability before using it to compute LCOE calculations. The standardised assumptions used for calculating the LCOE include the WACC, economic life and cost of bioenergy feedstocks.

### Weighted-average cost of capital

The analysis in previous IRENA cost reports assumed a 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 regulatory and economic policies tend to reduce the perceived risk of renewable energy projects and a WACC of 10% for the rest of the world.

These WACC 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.

For this edition of the report, the WACC assumptions have been reduced to reflect recent market conditions. This report assumes a WACC of 7.5% in 2010 for the OECD and China, declining to 5% in 2020. For the rest of the world a WACC of 10% is assumed in 2010, falling to 7.5% in 2020. The analysis behind this shift is discussed in more detail in the following section.

The increasing importance of Power Purchase Agreements (PPAs), auctions and tenders in the competitive procurement landscape of renewable energy has led to important differences among their designs between markets. Data available from these sources often reflect these differences. Where they are important, they have been corrected for a fair comparison between markets before their inclusion in IRENA's Auction and PPA Database and its analysis in this report. Examples of this include: harmonising indexed vs. non-indexed auction or PPA data, correcting for tax-credits influenced cost data (*e.g.,* US Investment or Production Tax Credit schemes), and excluding outliers. In these and other similar corrections, care has been taken to maintain the integrity of the data, while enabling the possibility of a more robust comparison that presents 'like-for-like' data.

**Table A1.1** Standardised assumptions for LCOE calculations

| Technology | Economic life (years) | Weighted average cost of capital (real) | |
|---|---|---|---|
| | | OECD and China | Rest of the world |
| Wind power | 25 | 7.5% in 2010 falling to 5% in 2020 | 10% in 2010 falling to 7.5% in 2020 |
| Solar PV | 25 | | |
| CSP | 25 | | |
| Hydropower | 30 | | |
| Biomass for power | 20 | | |
| Geothermal | 25 | | |

## CHANGING FINANCING CONDITIONS FOR RENEWABLES AND THE WEIGHTED AVERAGE COST OF CAPITAL

As already highlighted in, the value of the WACC assumed plays a critical role in determining the cost of electricity. Having more accurate WACC assumptions not only improves the advice IRENA can give its member countries, but also fills a gap for the broader energy modelling community. This is in critical need of improved renewable energy cost of capital data (Egli, Steffen and Schmidt, 2019). Changes in the cost of capital that are not properly accounted for over time – between countries or technologies can result in significant misrepresentations of the LCOE, leading to distorted policy recommendations.

Today, however, reliable data that comprehensively covers individual renewable technologies, across a representative number of countries and/or regions and through time remains remarkably sparse (Donovan and Nunez, 2012). This is typically due to the extreme difficulty in getting project-level financial information due its proprietary nature (Steffen, 2019). While evidence for declining and lower WACCs than assumptions previously used by is extensive (Steffen, 2019), it can be challenging to extract meaningful insights from the data contained in today's literature, as the majority of studies to date use inconsistent methodologies and may refer to different years, countries and technologies. A key challenge is the small number of countries for which data is available for each technology, and the relatively narrow 'snapshot' of financing conditions many studies provide.

Typically, existing studies have assessed only a single country, with just a few studies extending their analysis to five or more states. Most studies have also focused on onshore wind and solar PV only and limited their assessment to historical data, as opposed to developing a method and data basis for projections and associated scenarios. A broader coverage of countries/regions and technologies and the capability to develop scenarios that include the future cost of capital is critical for IRENA and other stakeholders, if a proper assessment of the LCOE across different world regions, technologies and over time is to be made.

In November 2019, IRENA conducted a workshop with experts in the field to discuss these issues and current WACC assumptions, in order to identify a way to improve data availability. In 2020, this resulted in IRENA, IEA Wind and ETH Zurich working together to benchmark WACC values by country, while also formulating a survey on the cost of finance for renewable energy projects that can be implemented online, but will also be supported by a number of semi-structured interviews with key stakeholders in order to understand the drivers behind financing costs and conditions. The goal is to develop a survey methodology which can be repeated periodically in the future.

The goal of this work is to arrive at detailed country and technology-specific WACC data for solar PV, onshore and offshore wind. This will be achieved by a three-pronged approach to data collection, that includes using data from:

*The energy modelling community need accurate Weighted Average Cost of Capital assumptions to improve renewable energy cost of capital data*

- **Desktop analysis**: This will combine two analytical methods to better understand WACCs. The first matches projects in the IRENA Renewable Cost Database and IRENA Auctions and PPA Database. It takes the adjusted PPA/auction price as the benchmark to vary the WACC in the LCOE calculation, with the other components of that calculation at the project level (*e.g.,* economic life, capacity factors, O&M costs and total installed costs) remaining fixed. This allows IRENA to reverse engineer an indicator of WACC. The second analytical method takes financial market data on risk-free lending rates, country risk premiums, lenders margins and equity risk premiums to develop country-specific WACC benchmarks for renewables.

- **An online survey**: Currently being undertaken by IRENA, IEA Wind Task 26 and ETH Zurich, this asks stakeholders with experience of financing renewable projects about the individual components that contribute to the WACC.

- **Semi-structured interviews**: These are designed to extract deeper insights about what is driving the differences in financing conditions for technologies in different countries. These will also seek to understand the variation in costs within countries based on factors such as the type of project, the organisation developing the project, etc. These interviews will be invaluable in understanding the nuances that impact financing conditions and the policy recommendations that can help ensure competitive financing conditions and low-cost electricity for the transition.

The desktop analysis aiming to derive benchmark WACC components (*e.g.,* debt cost, equity cost, debt-to-equity ratio, etc.) serves as a precursor to the online survey and the semi-structured interviews. The benchmarking process is also part of developing an enhanced understanding of the constituents of WACC and their key drivers, while also serving two goals: first, to provide insights into the underlying drivers of the WACC components; and second, the creation of a benchmarking cost of capital tool that can be used to fill in gaps in the survey analysis.[1] In addition to using the benchmark values created in this process to seed the online survey, the survey process itself will help refine the benchmarking tool, therefore improving its robustness.

For the first part of the benchmarking work, IRENA and ETH Zurich worked together to match utility-scale solar PV projects in the IRENA Renewable Cost Database and IRENA Auctions and PPA Database, with project-level total installed costs and capacity factors, country O&M values and standardised economic lifetimes. We then arrived at a WACC that yielded an LCOE that matched the adjusted PPA/auction price.

The results for India for planned years of commissioning from 2016 to 2020 were presented in Figure 1.11. The results for India are perhaps the most robust of the analyses conducted, as the extensive use of auctions in India and the relatively good availability of project-level data for total installed costs and capacity factors means there is less uncertainty over whether the LCOE variables in the project database are close to 'actual' for the project. However, the approach also yielded results that aligned with the literature in Germany and the United States. As an example, for Germany, the project data is much sparser, but the intense competition in Germany and efficient total installed cost structures reduce variation and yield values, hence resulting in figures that were in alignment with other studies that have surveyed the financial community for WACC values and compared across sources (Egli *et al.,* 2018 and Steffen, 2019).

*1 It is not feasible for survey stakeholders' project partners to provide real-world WACC components for solar PV, onshore and offshore wind in even a majority of the countries of the world. Therefore, the benchmark cost of capital tool will be essential in fleshing out gaps in the survey results to provide climate and energy modellers with data for all the countries/regions in their models.*

IREA, IEA Wind and ETH Zurich have also developed a benchmark cost of capital tool. The benchmark approach uses the following approach to calculate the WACC for renewable power generation projects:

$$WACC = c_e \frac{E}{D+E} + c_d * (1-T) * \frac{D}{D+E}$$

Where:
$C_e$ = Cost of equity
$C_d$ = Cost of debt
D = Market value of debt
E = Market value of equity
T = Corporate tax rate.

The cost of debt is calculated by combining the global risk-free rate (provided by current US government 10-year bonds at 1.68%) with a country risk premium for debt (based on credit default swap values[2]) and lenders' margins (a standardised assumption of 2% as a global baseline for lending margins for large private infrastructure debt). The cost of equity is the sum of the US long-run equity rate of return of 6.4% (or a premium of 4.7% over risk-free rate) plus country equity premium (if any), plus the technology equity risk premium (if any), plus the US risk-free rate. Debt-to-equity ratios and the technology risk premium are varied by technology, based on local market maturity.

Market maturity levels are based on the share of penetration of each technology. These have been arbitrarily defined as 'new', 'intermediate' and 'mature', depending on thresholds of 0%-5%, 5%-10% and 10%+ of cumulative installed capacity, respectively, and using fixed values of 60%, 70% and 80% for the debt-to-equity ratio, along with equity technology risk premiums of 1.5%, 2.4% and 3.25%, depending on market maturity.[3]

The benchmark tool creates nominal values for each WACC parameter, but assuming 1.8% inflation (roughly the value in the United States over the last decade), we can transform the results into real values, as shown in Figure 1.11.

The benchmark tool can work well,[4] but it tends to be less robust when encountering non-OECD countries with stable exchange rates and significant domestic financial liquidity. An example is Saudi Arabia, where a fixed exchange rate to the US dollar – along with the presence of a significant domestic financial sector – appears to show that the cost of capital benchmark tool yields WACC results that appear higher than those being demanded for projects in recent years. This highlights the importance of the three-pronged approach to populating a database of cost of capital for renewable projects. The benchmark tool no doubt works well for some countries, but less so for others and therefore, in some cases, needs data to tweak the settings to local values.

2 *This is based on work by Prof. A. Damodaran, the methodology used is described at https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3653512*

3 *This is an area where it is hoped the survey will yield new insights, as data for debt-to-equity ratios and implied technology risk premiums remains extremely poor. These values have been chosen as representative and are anecdotally supported, to some extent, by the available data (e.g., Egli, 2019 and Zhou, Wilson and Caldecott, 2021). Some results from the benchmark tool, however, do not appear to fit well when compared to dissimilar countries. It is clearly a priority area for better data.*

4 *There are obvious examples where this will not be the case, however. For instance, a large European utility with access to very low cost finance today can potentially finance a project off their balance sheet in countries with high financing costs, if they feel the project risks are low. This is clearly happening in some markets, where implied WACCs for some projects are lower than in-country finance cost data would suggest.*

Given the evidence supporting a revision of the WACC assumptions used by IRENA, for this report, we have lowered the WACC assumptions by 2.5% (in real terms) across the board, to 5% for the OECD and China and 7.5% for the rest of the world. This is merely an interim step before next year's report, which will use the results of the cost of finance survey and semi-structured interviews, as well as the desktop benchmarking analysis, to create a database of WACC assumptions that is differentiated by country and technology for all countries present in the IRENA Renewable Cost Database (a total of 166 countries at this time).

### Normalising auction and PPA prices

IRENA's Auction and PPA Database contains data on around 13 000 individual winning[5] auction or tender bids, as well as PPA contracts. The data are predominantly at the project level, but where the details of individual winning bids are not disclosed, the entries represent the total capacity of that particular auction.

The database also includes 16 600 projects of less than 1 MW in size, totalling around 4.5 GW of predominantly solar PV projects. These small-scale systems are not covered by the discussion below.

The database contains information on the project size, duration of payment, level of pricing and indexation method (if any), where available. This database provides a complementary view to the IRENA Renewable Cost Database, with its project installed cost, capacity factor and LCOE data.

The auction and PPA prices need to be treated with caution, however, as they do not necessarily fit the boundary conditions that would mean the prices revealed are comparable with the lifetime project cost as calculated in an LCOE.

To account for this, the data presented for auction and PPA prices in this report has been corrected, where sufficient data is available, to more closely reflect the boundary conditions for the LCOE calculations in this report. This is done in three primary areas:

1. Excluding projects which have auction/PPA conditions that are clearly incomparable with LOCE (*e.g.,* contract lengths of 10 years). This also excludes eliminating projects that are outliers, where IRENA cannot verify how realistic the contracted price is (*e.g.,* high prices might be realistic on islands, but not the mainland).

2. Deflating auction and PPA prices where no indexation to inflation is provided for in the contract, or where they are partially indexed to a price index (consumer or producer).

3. Removing the impact of financial support, where this impact can be robustly calculated.

Once these corrections are made, the auction and PPA pricing data does, however, provide unique insights into where market prices for renewable electricity are trending, given delivery is typically for two or more years in the future. Crucially, although auction prices conceal all the assumptions that are necessary to calculate an LCOE, these prices can be benchmarked against LCOE trends to improve our understanding of cost trends and, in some cases, levels in different markets.

5 *Only data on the price trends of winning bids are presented in this report, although the database also contains some information on losing bids for a subset of auctions. Additionally, the database also includes the subsidy values for Chinese solar PV projects awarded support in 2019 and 2020, given the importance of the Chinese market in total deployment.*

Looking at point 2 above, there are two main areas where the terms and conditions of the projects in the IRENA Auction and PPA Database are subject to divergence from LCOE boundary conditions. The first is in the contract period over which the price holds, while the second is in the method of indexation.

The contract periods of the winning bids (where known) range from 10 to 35, in some cases diverging from the economic life assumed for solar and wind power technologies for the LCOE calculations in this report, as noted above. Correcting for this can be extremely difficult, as the WACC is unknown and the so-called 'merchant tail' of revenues, which occurs 15 or 20 years in the future, is difficult to know with any certainty.[6] IRENA has excluded projects with contract durations of 10 years or less in the charts presented in this report.

The second challenge is the method of indexation used on the 'strike' price of the auction. In the majority of cases, there is no indexation, so prices received are nominal. All the data presented in this report are corrected for this, using the consumer price index average annual inflation rate for the last decade of 1.8% per year in order to ensure they are at least calculated on a real basis – the same as the LCOE values presented in this report.

Finally, the impact of other financial support that would impact contract pricing is removed if possible. This is most important for the United States, and IRENA has therefore removed the impact of the Investment Tax Credit (ITC) on solar PV and Production Tax Credit (PTC) on onshore wind auction and PPA prices in the United States.

## O&M COSTS

### Solar PV

Depending on the commissioning year, a different O&M cost assumption is used for the calculation of the solar PV LCOE estimates calculated in this report. An additional distinction is made depending on whether the project has been commissioned in a country belonging to the OECD or not (Table A1.2).

### Onshore wind

Based on the annual range of O&M onshore wind costs in China, India and the rest of the world for the 448 project subset with O&M data in the IRENA Renewable Cost Database, the largest share of O&M costs is represented by maintenance operations, which have a weighted average of 67%, followed by salaries at 14% and materials at 7% (IRENA, 2018). Based on IRENA's O&M data and data from IEA Wind Task 26 and others for new project- and country-level data IRENA has gathered, country or regional O&M costs are calculated. For the majority of countries and projects, the average O&M cost falls between USD 0.006/kWh and USD 0.02/kWh.

### Offshore wind

The O&M cost assumptions used are based on estimates that fall between USD 0.017/kWh and USD 0.030/kWh, when converted from average costs in USD/kW/year (IEA *et al.*, 2018; Ørsted, 2019; Stehly *et al.*, 2018). The lower range is seen in projects in China and established European markets with sites closer to shore, while the latter, higher-cost range is seen in less-established offshore wind markets or markets with harsher ocean and meteorological conditions.

*6 Having said this, with the data for the last three years in the IRENA Auction and PPA Database having a weighted-average contract length of around 20 years for both onshore wind and utility-scale solar PV, the impact these 'merchant tails' have on the implied LCOE would not be large, except in the case of projects with either a very low WACC or a very large discrepancy.*

**Table A1.2** O&M cost assumptions for the LCOE calculation of PV projects

| Year | OECD 2020 USD/kW/year | Non-OECD 2020 USD/kW/year |
|---|---|---|
| 2010 | 26.2 | 24.7 |
| 2011 | 23.2 | 22.7 |
| 2012 | 22.6 | 17.6 |
| 2013 | 22.1 | 14.8 |
| 2014 | 21.6 | 13.2 |
| 2015 | 20.9 | 12.0 |
| 2016 | 20.4 | 10.9 |
| 2017 | 20.8 | 10.5 |
| 2018 | 19.4 | 10.0 |
| 2019 | 18.5 | 9.6 |
| 2020 | 17.6 | 9.3 |

*Source: IRENA Renewable Cost Database*

## TOTAL INSTALLED COST BREAKDOWN: DETAILED CATEGORIES FOR SOLAR PV

IRENA has for some years collected cost data on a consistent basis at a detailed level for a selection of PV markets. In addition to tracking average module and inverter costs, the balance of system costs are broken down into three broad categories: non-module and inverter hardware, installation costs, and soft costs. These three categories are composed of more detailed sub-categories which can greater understanding of the drivers of solar PV balance of system (BoS) costs and are the basis for such analysis in this report.

Anlaysis of coal-fired power plant operating costs in Bulgaria, China, Germany and India, when it comes to generation levels (in order to calculate capacity factors, and with the exception of the Bulgarian lignite plants) and in 2021 for fuel costs, where plants are exposed to market prices.[7] The figure also includes the weighted-average PPA price for projects to be commissioned in 2021, or in the case of Bulgaria, an estimate of the LCOE of solar and onshore wind utilisation costs – representative for South East Europe – based on projects currently in development.[8]

The calculations presented here should therefore be treated with caution, because a number of uncertainties exist. When looking at fuel costs, there are uncertainties around the exact delivered cost of coal to many plants. This is because, outside the analysis for the United States and for coastal plants using imported coal, plant-level fuel costs are not reported. In their absence, cost-plus models of mining and delivery costs are estimated. These may be accurate in aggregate, but not for individual plants. Similarly, the availability of plant-level O&M costs outside the United States and Bulgaria is patchy, and assumptions derived from plant age, technology and country are used.

7 *This analysis is predominantly based on updating the following sources: Carbon Tracker, 2018; Szabó, L., et al., 2020; Öko-Institut, 2017; DIW Berlin, Wuppertal Institut and EcoLogic, 2019; and Vibrant Clean Energy, 2019. The updates draw on a number of sources, including Booz&Co, 2014; Coal India, 2020; Energy-charts.de, 2021; IEA, 2021; NPP, 2021; and US EIA, 2021.*

8 *The assumptions for solar PV are EUR 740/kW (USD 830/kW) and a capacity factor of 13%, while for wind, the assumptions are EUR 1 500/kW (USD 1 685/kW) and a 36% capacity factor.*

**Table A1.3** BoS cost breakdown categories for solar PV

| Category | Description |
|---|---|
| **Non-module hardware** | |
| Cabling | · All direct current (DC) components, such as DC cables, connectors and DC combiner boxes<br>· All AC low voltage components, such as cables, connectors and AC combiner boxes |
| Racking and mounting | · Complete mounting system including ramming profiles, foundations and all material for assembling<br>· All material necessary for mounting the inverter and all type of combiner boxes |
| Safety and security | · Fences<br>· Camera and security system<br>· All equipment fixed installed as theft and/or fire protection |
| Grid connection | · All medium voltage cables and connectors<br>· Switch gears and control boards<br>· Transformers and/or transformer stations<br>· Substation and housing<br>· Meter(s) |
| Monitoring and control | · Monitoring system<br>· Meteorological system (*e.g.,* irradiation and temperature sensor)<br>· Supervisory control and data system |
| **Installation** | |
| Mechanical installation (construction) | · Access and internal roads<br>· Preparation for cable routing (*e.g.,* cable trench, cable trunking system)<br>· Installation of mounting/racking system<br>· Installation of solar modules and inverters<br>· Installation of grid connection components<br>· Uploading and transport of components/equipment |
| Electrical installation | · DC installation (module interconnection and DC cabling)<br>· AC medium voltage installation<br>· Installation of monitoring and control system<br>· Electrical tests (*e.g.,* DC string measurement) |
| Inspection (construction supervision) | · Construction supervision<br>· Health and safety inspections |
| **Soft costs** | |
| Incentive application | · All costs related to compliance in order to benefit from support policies |
| Permitting | · All costs for permits necessary for developing, construction and operation<br>· All costs related to environmental regulations |
| System design | · Costs for geological surveys or structural analysis<br>· Costs for surveyors<br>· Costs for conceptual and detailed design<br>· Costs for preparation of documentation |
| Customer acquisition | · Costs for project rights, if any<br>· Any type of provision paid to get project and/or off-take agreements in place |
| Financing costs | · All financing costs necessary for development and construction of PV system, such as costs for construction finance |
| Margin | · Margin for EPC company and/or for project developer for development and construction of PV system includes profit, wages, finance, customer service, legal, human resources, rent, office supplies, purchased corporate professional services and vehicle fees |

*Source: IRENA.*

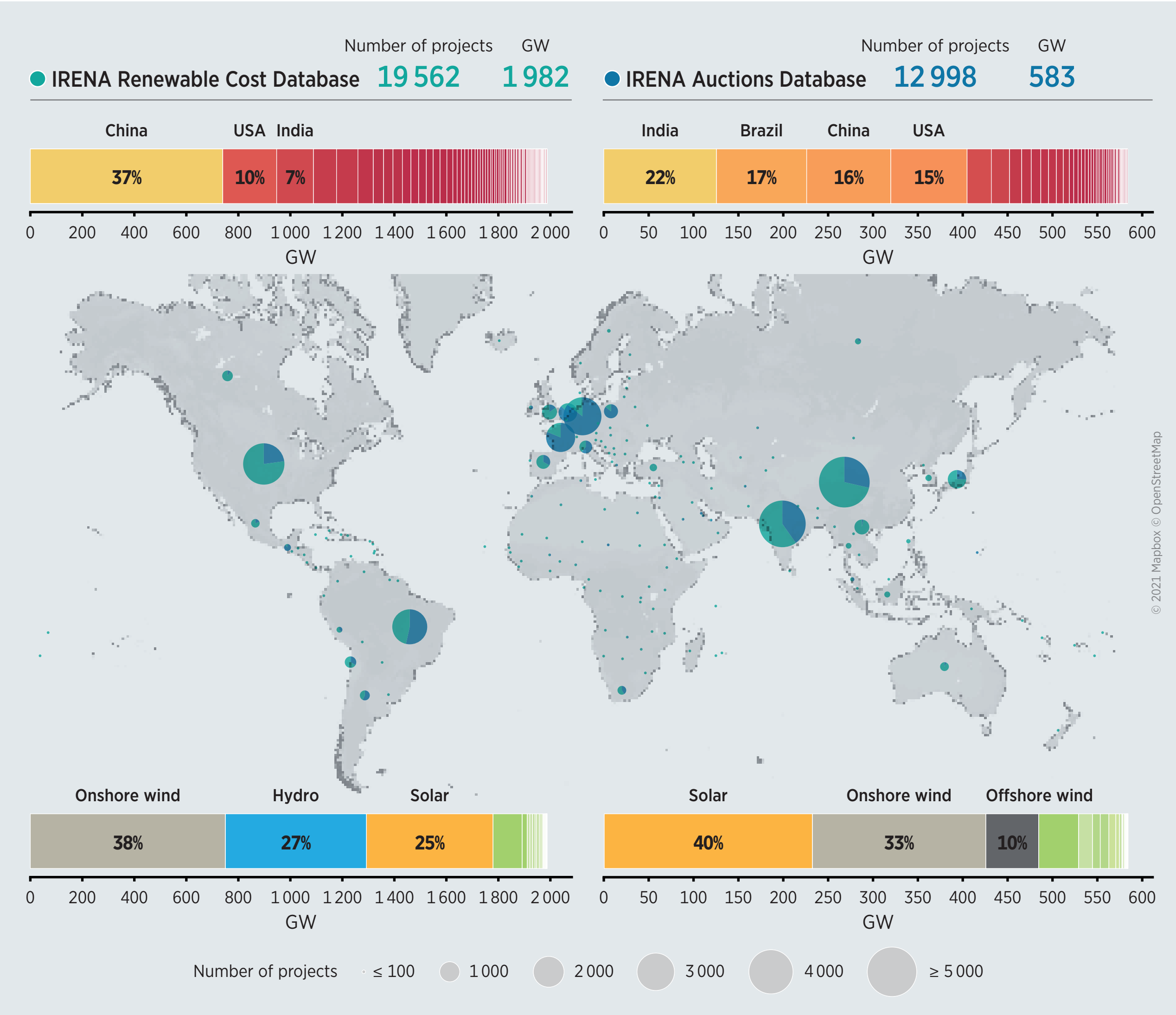
# ANNEX II

## THE IRENA RENEWABLE COST DATABASE

The composition of the IRENA Renewable Cost Database largely reflects the deployment of renewable energy technologies over the last ten to fifteen years. Most projects in the database are in China (740 GW), the United States (208 GW), India (140 GW), and Germany (90 GW).

Collecting cost data from OECD countries, however, is significantly more difficult due to greater sensitivities around confidentiality issues. The exception is the United States, where the nature of support policies leads to greater quantities of project data being available

**Figure A2.1** Distribution of projects by technology and country in IRENA's Renewable Cost Database and Auction and PPA Database




*Disclaimer: This map is provided for illustration purposes only. Boundaries and names shown on this map do not imply any official endorsement or acceptance by IRENA.*

After these four major countries, Brazil is represented by 81 GW of projects, the United Kingdom by 60 GW, Spain by 39 GW, Viet Nam and Japan are represented by 36 GW of projects, Italy by 33 GW, Australia by 29 GW and Canada by 28 GW of projects.

Onshore wind is the largest single renewable energy technology represented in the IRENA Renewable Cost Database, with 750 GW of project data available from 1983 onwards. Hydropower is the second largest technology represented in the database with 542 GW of projects since 1961, with around 90% of those projects commissioned in the year 2000 or later. Cost data is available for 488 GW of solar PV projects, 109 GW of commissioned and proposed offshore wind projects, 75 GW of biomass for power projects, 10 GW of geothermal projects and around 8 GW of CSP projects.

The coverage of the IRENA Renewable Cost Database is more or less complete for offshore wind and CSP, where the relatively small number of projects can be more easily tracked. The database for onshore wind and hydropower is representative from around 2007, with comprehensive data from around 2009 onwards. Gaps in some years for some countries that are in the top ten for deployment in a given year require recourse to secondary sources, however, in order to develop statistically representative averages. Data for solar PV at the utility-scale has only become available more recently and the database is representative from around 2011 onwards, and comprehensive from around 2013 onwards.

# ANNEX III
## REGIONAL GROUPINGS

**Asia**
Afghanistan, Bangladesh, Bhutan, Brunei Darussalam, Cambodia, People's Republic of China, Democratic People's Republic of Korea, India, Indonesia, Japan, Kazakhstan, Kyrgyzstan, Lao People's Democratic Republic, Malaysia, Maldives, Mongolia, Myanmar, Nepal, Pakistan, Philippines, Republic of Korea, Singapore, Sri Lanka, Tajikistan, Thailand, Timor-Leste, Turkmenistan, Uzbekistan, Viet Nam.

**Africa**
Algeria, Angola, Benin, Botswana, Burkina Faso, Burundi, Cabo Verde, Cameroon, Central African Republic, Chad, Comoros, Congo, Côte d'Ivoire, Democratic Republic of the Congo, Djibouti, Egypt, Equatorial Guinea, Eritrea, Ethiopia, Eswatini, Gabon, Gambia, Ghana, Guinea, Guinea- Bissau, Kenya, Lesotho, Liberia, Libya, Madagascar, Malawi, Mali, Mauritania, Mauritius, Morocco, Mozambique, Namibia, Niger, Nigeria, Rwanda, Sao Tome and Principe, Senegal, Seychelles, Sierra Leone, Somalia, South Africa, South Sudan, Sudan, Togo, Tunisia, Uganda, United Republic of Tanzania, Zambia, Zimbabwe.

**Central America and the Caribbean**
Antigua and Barbuda, Bahamas, Barbados, Belize, Costa Rica, Cuba, Dominica, Dominican Republic, El Salvador, Grenada, Guatemala, Haiti, Honduras, Jamaica, Nicaragua, Panama, Saint Kitts and Nevis, Saint Lucia, Saint Vincent and the Grenadines, Trinidad and Tobago.

**Eurasia**
Armenia, Azerbaijan, Georgia, Russian Federation, Turkey.

**Europe**
Albania, Andorra, Austria, Belarus, Belgium, Bosnia and Herzegovina, Bulgaria, Croatia, Cyprus, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Latvia, Liechtenstein, Lithuania, Luxembourg, Malta, Monaco, Montenegro, Kingdom of the Netherlands, Norway, Poland, Portugal, Republic of Moldova, Romania, San Marino, Serbia, Slovakia, Slovenia, Spain, Sweden, Switzerland, Ukraine, United Kingdom of Great Britain and Northern Ireland.

**Middle East**
Bahrain, Islamic Republic of Iran, Iraq, Israel, Jordan, Kuwait, Lebanon, Oman, Qatar, Kingdom of Saudi Arabia, Syrian Arab Republic, United Arab Emirates, Yemen.

**North America**
Canada, Mexico, United States of America.

**Oceania**
Australia, Fiji, Kiribati, Marshall Islands, Micronesia (Federated States of), Nauru, New Zealand, Palau, Papua New Guinea, Samoa, Solomon Islands, Tonga, Tuvalu, Vanuatu.

**South America**
Argentina, Bolivia (Plurinational State of), Brazil, Chile, Colombia, Ecuador, Guyana, Paraguay, Peru, Suriname, Uruguay, Venezuela (Bolivarian Republic of).

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# RENEWABLE POWER GENERATION COSTS IN 2020

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