IRENA
International Renewable Energy Agency

RENEWABLE POWER GENERATION COSTS IN 2021

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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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The growing competitiveness of renewable energy continues to provide the most compelling pathway to the decarbonisation of the global energy system

FOREWORD

Francesco La Camera

Director-General

International Renewable Energy Agency

The competitiveness of renewables continued to improve in 2021, with data from the IRENA Renewable Cost Database indicating an ongoing decline in the cost of electricity generated by renewables and affirming their essential role in the journey towards a net zero future.

Renewables represent a vital pillar in the global effort to reduce and ultimately phase out fossil fuels, increasing national resilience in the face of fossil fuel price volatility.

High coal and fossil gas prices in 2021 and 2022 have further undermined the competitiveness of fossil fuels, making solar and wind even more attractive. With the unprecedented surge in European fossil gas prices, new fossil gas generation in Europe will increasingly become uneconomic over its lifetime, bringing the high risk of stranded assets.

Conversely, the world has witnessed a seismic shift in the competitiveness of renewable power generation options since 2010. The global weighted average levelised cost of electricity (LCOE) of newly commissioned utility-scale solar PV projects declined by 88% between 2010 and 2021, while onshore wind fell by 68%, Concentrating Solar Power (CSP) by 67% and offshore wind by 60%.

Rising commodity and renewable equipment prices are passed through into project costs with a lag, given the time difference between a financial investment decision and the commissioning of a project. Given this, the global weighted average costs of solar photovoltaics (PV), as well as onshore and offshore wind power fell in 2021.

The levelised cost of electricity from solar PV fell by 13%, whilst onshore and offshore wind fell by 15% and 13%, respectively, compared to 2020.

Almost two-thirds – or 163 gigawatts (GW) – of newly installed renewable power in 2021 had lower costs than the world's cheapest coal-fired options in the G20, confirming the critical role of cost-competitive renewables in addressing today's energy and climate crises.

The global weighted average LCOE of new utility-scale solar PV and hydropower was 11% lower than the cheapest new fossil fuel-fired power generation option in 2021, and 39% lower for onshore wind.

Cost reductions were not universal, however, as the weighted average total installed costs of utility-scale solar PV increased year-on-year in 3 of the top 25 markets, and in 7 for onshore wind in 2021.

Furthermore, geothermal and bioenergy remained, on average, more expensive than the cheapest fossil fuel-fired option globally – albeit highly competitive in some non-OECD regions.

IRENA's data also suggest that some material cost increases are yet to be passed through into equipment prices and project costs. If materials prices remain elevated, the price pressures in 2022 will be more pronounced and overall costs may rise.

Nonetheless, extremely high fossil fuel prices mean that any plausible scenario for renewable cost increases are outweighed by the extensive economic benefits of new renewable capacity overall.

This only strengthens the conclusion of IRENA's *World Energy Transitions Outlook 2022* that low-cost renewable energy provides the most compelling pathway to the decarbonisation of the global future energy system and the achievement of both the 1.5°C target and the goals of the Paris Agreement.

If ever there was a year to dramatically increase the deployment of renewable power generation, it is 2022. Renewables will reduce fossil import bills and average electricity system costs, and lessen the damaging impacts of high electricity prices on consumers and industry. This year's fossil fuel price crisis demands a response; renewables and energy efficiency provide the answer, bringing unprecedented benefits for consumers, the environment and the global economy.

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ABBREVIATIONS

AC	alternating current
BoS	balance of system
CCGT	combined-cycle gas turbine
CCS	carbon capture and storage
CHP	combined heat and power
CO_2	carbon dioxide
COD	commercial operation date
CSP	concentrating solar power
DC	direct current
DCF	discounted cash flow
DNI	direct normal irradiation
DWS	diamond wire sawing
EEA	European Economic Area
EIA	The U.S. Energy Information Administration
EPC	engineering, procurement and construction
ETS	Emissions Trading Scheme
EU	European Union
FF	fossil fuel
GW	gigawatts
HJT	heterojunction
HTF	heat transfer fluid
IBC	interdigitated back contact
IEA	The International Energy Agency
IFC	The International Finance Corporation
ILR	inverter loading ratio
IMF	International Monetary Fund
IPCC	The Intergovernmental Panel on Climate Change
IPP	independent power producer
kg	kilogramme
kWh	kilowatt hour
LCOE	levelised cost of electricity
LNG	liquefied natural gas
mg	milligrammes
mm	millimetres
MW	megawatts
MWh	megawatt hour
O&M	operations and maintenance
OECD	the Organisation of Economic Co-operation and Development
OEM	original equipment manufacturer
OPEX	operational expenses
PERC	passivated emitter and rear cell
PPA	Power Purchase Agreement
PTC	parabolic trough collector
PV	photovoltaic
STs	Solar towers
TTF	Title Transfer Facility
TWh	terawatt hours
USD	US dollars
VRE	variable renewable energy
WACC	weighted average cost of capital
WACC	watt
µm	micrometre

HIGHLIGHTS

The global weighted average cost of newly commissioned solar photovoltaics (PV), onshore and offshore wind power projects fell in 2021. This was despite rising materials and equipment costs, given that there is a significant lag in the pass through to total installed costs.

The global weighted average levelised cost of electricity (LCOE) of new onshore wind projects added in 2021 fell by 15%, year-on-year, to USD 0.033/kWh, while that of new utility-scale solar PV projects fell by 13% year-on-year to USD 0.048/kWh and that of offshore wind declined 13% to USD 0.075/kWh. With only one concentrating solar power (CSP) plant commissioned in 2021, the LCOE rose 7% year-on-year to USD 0.114/kWh.

The period 2010 to 2021 has witnessed a seismic improvement in the competitiveness of renewables. The global weighted average LCOE of newly commissioned utility-scale solar PV projects declined by 88% between 2010 and 2021, whilst that of onshore wind fell by 68%, CSP by 68% and offshore wind by 60%.

The benefits from renewables in 2022 will be unprecedented, given the fossil fuel price crisis:

- The lifetime cost per kWh of new solar and wind capacity added in Europe in 2021 will average at least four to six times less than the marginal generating costs of fossil fuels in 2022.
- Globally, the new renewable capacity added in 2021 could reduce electricity generation costs in 2022 by at least USD 55 billion.
- Between January and May 2022 in Europe, solar and wind generation, alone, avoided fossil fuel imports of at least USD 50 billion.

The data suggests that not all of the materials cost increases witnessed to date have been passed through into equipment prices. This suggests that price pressures in 2022 will be more pronounced than in 2021 and total installed costs are likely to rise this year in more markets.

Table H.1 Global weighted average total installed cost, capacity factor and levelised cost of electricity trends by technology, 2010 and 2021

	Total installed costs (2021 USD/kW)			Capacity factor (%)			Levelised cost of electricity (2021 USD/kWh)		
	2010	2021	Percent change	2010	2021	Percent change	2010	2021	Percent change
Bioenergy	2 714	2 353	-13%	72	68	-6%	0.078	0.067	-14%
Geothermal	2 714	3 991	47%	87	77	-11%	0.050	0.068	34%
Hydropower	1 315	2 135	62%	44	45	2%	0.039	0.048	24%
Solar PV	4 808	857	-82%	14	17	25%	0.417	0.048	-88%
CSP	9 422	9 091	-4%	30	80	167%	0.358	0.114	-68%
Onshore wind	2 042	1 325	-35%	27	39	44%	0.102	0.033	-68%
Offshore wind	4 876	2 858	-41%	38	39	3%	0.188	0.075	-60%

EXECUTIVE SUMMARY

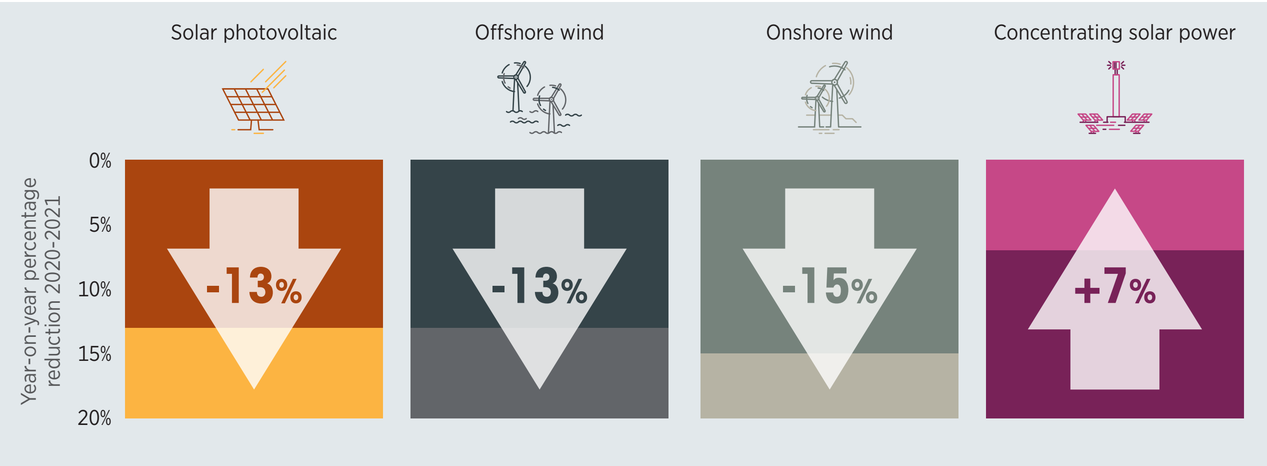
The competitiveness of renewables continued to improve in 2021. Data from the IRENA Renewable Cost Database and analysis of recent power sector trends affirm their essential role in the journey towards an affordable and technically feasible net zero future.

The global weighted average cost of electricity of newly commissioned solar photovoltaics (PV), and onshore and offshore wind power projects fell in 2021. This was despite rising commodity and renewable equipment prices in 2021, given the notable lag before these cost increases appear in project total installed costs. Meanwhile, significant improvements in performance in 2021 raised capacity factors, especially for onshore wind.

The global weighted average levelised cost of electricity (LCOE) of new utility-scale solar PV projects commissioned in 2021 fell by 13% year-on-year, from USD 0.055/kWh to USD 0.048/kWh. With only one concentrating solar power (CSP) plant commissioned in 2021, after two in 2020, deployment remains limited and year-to-year cost changes volatile. Noting this caveat, the average cost of electricity from the new CSP plant was around 7% higher than the average in 2020.

The global weighted average LCOE of new onshore wind projects added in 2021 fell by 15%, year-on-year, from USD 0.039/kilowatt hour (kWh) in 2020 to USD 0.033/kWh. China again dominated new onshore wind capacity additions in 2021 and also experienced, against the trend elsewhere, falling wind turbine prices. The cost of electricity for new onshore wind projects excluding China fell by a more modest 12% year-on-year to USD 0.037/kWh. The offshore wind market saw unprecedented expansion in 2021 (21 GW added), as China increased its new capacity additions and the global weighted average cost of electricity fell by 13% year-on-year, from USD 0.086/kWh to USD 0.075/kWh.

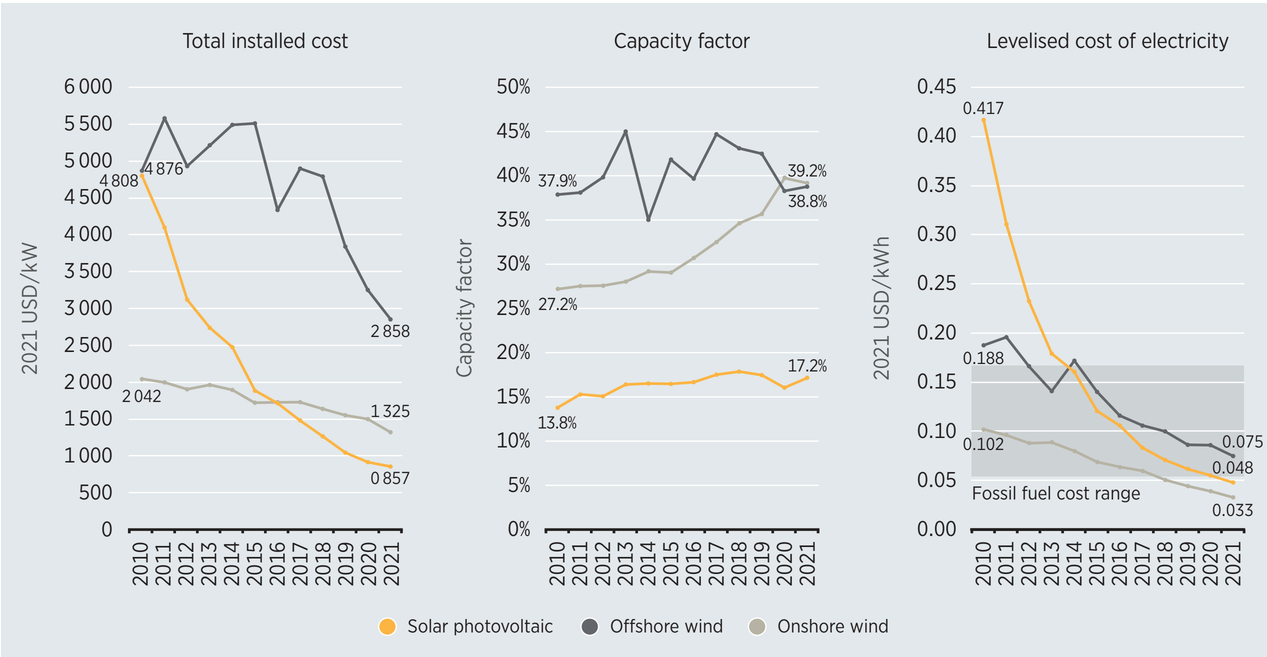
Figure S.1 Change in global weighted levelised cost of electricity by technology, 2020-2021



Cost reductions were not universal, however; the country weighted average total installed costs of utility-scale solar PV increased year-on-year in three of the top 25 markets, while for onshore wind this was true of seven of the top 25 markets in 2021.

The period 2010 to 2021 has witnessed a seismic shift in the balance of competitiveness between renewables and incumbent fossil fuel and nuclear options. The global weighted average LCOE of newly commissioned utility-scale solar PV projects declined by 88% between 2010 and 2021, whilst that of onshore wind and CSP fell by 68%, and offshore wind by 60% (Figure S.2).

Figure S.2 Global weighted average total installed costs, capacity factors and LCOE of newly commissioned utility-scale solar PV, onshore and offshore wind, 2010-2021



In 2021, the global weighted average LCOE of new utility-scale solar PV and hydropower was 11% lower than the cheapest new fossil fuel-fired power generation option, whilst that of onshore wind was 39% lower. Geothermal and bioenergy globally remain, on average, more expensive than the cheapest fossil fuel-fired option, but provide secure supply and can be very competitive in non-OECD regions.

Rising commodity prices – especially materials prices such as steel, copper, polysilicon and aluminium – saw module and wind turbine prices rise from around Q4 2020. Depending on materials prices and other supply chain pressures over the rest of this year, solar PV module prices might average a fifth more than they did in 2020. Yet, in 2021, the global weighted average cost of electricity from new solar PV and onshore wind fell. There are a number of potential reasons for this, including:

- Overall equipment cost increases were modest in late 2020 and into early 2021, when many projects commissioned in 2021 would have placed orders.

- Larger projects have greater purchasing power and longer lead times, and are increasingly dominating capacity additions outside Europe.

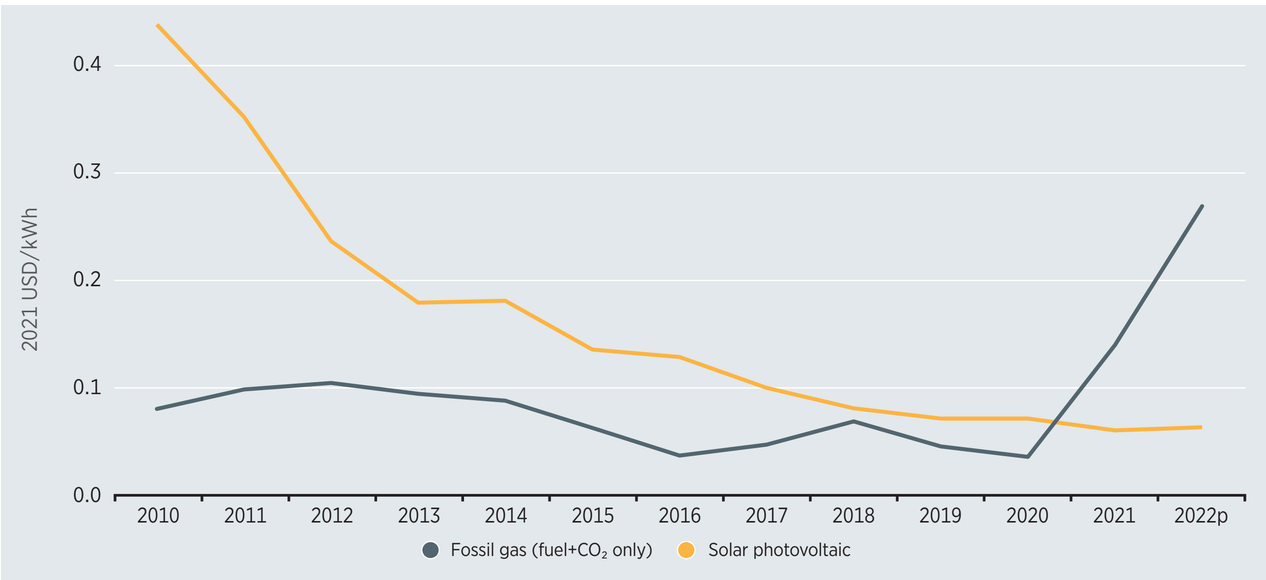
- Contingency allowances in many projects will have absorbed some or all of any increased costs.
- Technology improvements (*e.g.* more efficient PV modules and larger wind turbines) and improvements in manufacturing efficiency and scale continue.
- China remains the dominant market for new solar and wind and has lower commodity prices and transport costs, while wind project developers squeezed turbine price reductions from manufacturers in 2021.

However, the data suggests that not all of the materials cost increases witnessed to date have been passed through into equipment prices, and manufacturer's margins have also been squeezed. If materials prices remain elevated in 2022, this suggests – when combined with the lag between materials cost increases and project costs – that price pressures in 2022 will be more pronounced than in 2021 and total installed costs are likely to rise this year in more markets.

The impact on the levelised cost of electricity for solar PV and onshore wind is, however, likely to be modest – in the order of 2-4% for utility-scale solar PV and 4-9% for onshore wind. A return to the more sustainable profit margins seen in 2017 might increase this figure for onshore wind to an 8% to 12% increase, but it is not clear if all these cost increases could be passed through in 2022 alone. More importantly, with the extremely high fossil fuel prices already experienced in 2022 likely to continue, the additional cost is outweighed many times over by the economic benefits of new renewable capacity.

Indeed, the extent of the benefits from renewables in 2022 will be unprecedented. Assuming average wholesale fossil gas prices in 2022 of USD 0.109/kWh in Europe, the average generated fuel-only cost (excludes carbon dioxide [CO_2] prices) of existing fossil gas generators will be in the order of USD 0.23/kWh, or 540% higher than in 2020. The European Union (EU) Emissions Trading Scheme (ETS) emission price raises fuel costs to USD 0.27/kWh in 2022, or 645% higher than in 2020, (Figure S.3).

Figure S.3 The weighted average LCOE of utility scale solar PV compared to fuel and CO_2 cost only for fossil gas in Europe, 2010-2022



Note: 2022 values are possible outcomes for 2022 and not a forecast.

To put this figure of USD 0.27/kWh in context; this is 4 to 6 times more expensive than the new solar and onshore wind capacity added in Europe in 2021 and it exceeds the average retail tariff (excluding taxes and levies) paid by households in 13 of the 27 EU countries in 2020 to cover transmission, distribution, wholesale electricity purchases, marketing and overheads.

Countries, investments in renewables are paying huge dividends in 2022. Globally, new renewable capacity added in 2021 could save USD 55 billion this year alone, given the fossil fuel price crisis. Looking at the benefit of the cumulative stock of renewables draws an even starker picture. In Europe, between January and May 2022, solar PV and wind generation alone have likely avoided in the order USD 50 billion in fossil fuel imports – predominantly of fossil gas. The unprecedented extent of the fossil fuel price crisis in 2022 has overshadowed the fact that, without renewables, the situation for consumers, economies and the environment would be much worse.

Marginal fossil fuel electricity generating costs are so high in 2022 that renewable projects added in 2021 could return many times their required annual capital repayments. An onshore wind plant - online on or before 1 January 2022 and able to capture the marginal fossil fuel generation costs in 2022 - might receive between twice (in Mexico) to thirteen times (in Brazil) the required annual return on capital for the year. That countries have not prioritised accelerated renewable power generation capacity deployment, but left the response largely to individuals and businesses, will likely cost society billions of dollars this year and the next in direct energy costs. This is before accounting for the macroeconomic damage that accrues from the fossil fuel price crisis.

01 LATEST COST TRENDS

INTRODUCTION

As the world emerged from the first phase of the COVID-19 global pandemic – a period characterised by lockdowns, significant numbers of deaths and economic slowdowns – the year 2021 saw a 'new normal' begin in which vaccinations were ramped up – albeit unequally – and economic activity rebounded.

Yet, 2021 also brought its own challenges. The emergence of new, more transmissible variants of the virus marred recovery in many countries, while the rapid rebound in economic activity put pressure on utilities and supply chains around the world. The resulting increase in the price of commodities, including fossil fuels, developed into a fully-fledged crisis in Europe, as fossil fuel storage levels remained consistently low over the summer, causing significant concern and price rises ahead of the northern hemisphere winter.

Despite the supply chain challenges of 2021, new capacity additions, at 257 gigawatts (GW),[1] were only 3% lower than in 2020, but were 41% higher than the 182 GW added in 2019, which was a record year at the time (IRENA, 2022a). Between 2000 and 2021, renewable power generation capacity worldwide increased just over four-fold, from 754 GW to 3 064 GW (IRENA, 2022a).

Indeed, renewables are increasingly becoming the default source of least cost, new power generation. When this is combined with the impact of the fossil fuel crisis and net-zero emissions ambitions, capacity additions are expected to continue to rise in the years ahead.

[1] *All data in this report, unless expressly indicated, refers to the year a project was commissioned. This is sometimes referred to as the commercial operation date (COD). 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.*

In 2021, solar photovoltaic (PV) was once again the largest contributor to the total, with new capacity additions of 133 GW commissioned. Meanwhile, wind power capacity grew by 93 GW (with onshore wind power accounting for 72 GW of this growth). This was after record new onshore wind capacity additions in 2020, when 105 GW was added. That record had been driven by a surge in delayed connections in China, which accounted for 69 GW of the new projects that year. A reduction in new additions in 2021 was therefore always likely, China's onshore wind additions in 2021 amounted to 29 GW, a reduction of around 40 GW, year-on-year. Growth in other markets, however, limited the global decline, with notable additions in Brazil (up 4 GW) Viet Nam (up 2.7 GW), Sweden (up 2.1 GW), Türkiye (up 1.8 GW) and France (up 1.2 GW).

At the same time, in contrast to onshore, offshore wind additions surged to 17.4 GW in China, meaning global additions went from 6 GW in 2020 to 21 GW in 2021, with China accounting for 82% of the total.

In 2021, hydropower capacity increased by 23 GW – in contrast to the 16 GW added in 2019 and the 11 GW added in 2020. China added 14.6 GW of the 2021 total, while Canada added 1.3 GW.

Meanwhile, bioenergy power generation capacity increased by 10.3 GW in 2021, up from the 9.1 GW added in 2020. Most of the expansion for bioenergy also occurred in China, which commissioned 6.2 GW, with North America the only other region to make more than 1 GW of new additions.

Elsewhere, additions of geothermal power were modest and it appears that only 110 megawatts (MW) of concentrating solar power (CSP) capacity was connected to the grid in 2021, via a project in Chile.

Yet again, in 2021, the growth in new capacity additions for fossil and nuclear fuels lagged that of renewables. This resulted in renewables' share of total power generation capacity growth reaching 81% in 2021 – up from 79% in 2020. Indeed, since 2012, renewables have accounted for at least half of all new net capacity additions worldwide (IRENA, 2022a).

IRENA's cost analysis programme has been collecting and reporting the cost and performance data of renewable power generation technologies since 2012. The goal is to provide transparent, up-to-date cost and performance data from a reliable source given this data is vital in ensuring the potential of renewable energy is properly taken into account by policy makers, energy and climate modellers and other stakeholders. Without this data, these key decision makers in the energy sector will struggle to correctly identify the magnitude of the role renewable energy can play in meeting our shared economic, environmental and social goals for the energy transition. The reason for this is not new, with the high cost reduction rates and rapid growth in installed capacity of renewable energy technologies meaning that comprehensive and up-to-date data, by market and technology, is essential.

The share of renewables in total power generation capacity growth reached 81% in 2021, up from 79% in 2020

IRENA maintains two core databases. These have been created to ensure IRENA can respond to its member states' needs, while also ensuring that industry and civil society have easy access to the latest renewable power generation cost and performance data. The databases are:

- **The IRENA Renewable Cost Database:** This includes project-level cost and performance data for around 2 100 GW of capacity from around 21 000 projects,[2] commissioned up to and including 2021.

- **The IRENA Auction and Power Purchase Agreement (PPA) Database:** This database contains data on around 13 500 projects, or programme results, where pricing data is not disclosed for individual winners.

In summarising the latest cost and performance data for projects commissioned in 2021, as well as the costs and trends for important equipment benchmarks (*e.g.* solar PV modules) and technology characteristics (*e.g.* onshore wind turbine capacity sizes), this report presents a consistent set of core metrics with which to measure the cost and performance of renewable power generation technologies. The latest data from the IRENA Auction and PPA Database is not included in this report, but will be the subject of a forthcoming data release by IRENA.

The breadth and depth of the data in the IRENA Renewable Cost Database allows for a meaningful understanding of variations between countries and technologies, as well as through time. These variations are reported across each technology, and allow an analysis of how differences have changed through time between particular technologies (*e.g.* solar PV and onshore wind) and the markets for those technologies.

In recent years, IRENA has also invested more resources in collecting benchmark equipment costs and total installed cost breakdowns, particularly for solar PV, in order to understand underlying cost reduction drivers and the differences between markets. IRENA has also expanded the range of cost and performance metrics it tracks. It now reports regularly on an increasing range of cost and performance metrics.

In expanding this data collection process, IRENA has benefitted from the support of the European Commission and this report includes a number of insights resulting from that (IRENA, 2022b). 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. For solar PV, increases in cell and module sizing, reduced wafer thickness, lower silver usage, and other developments all help better understand the underlying technology factors that are contributing to cost reductions. This is in addition to enabling better understanding of market drivers, such as increased economies of scale, that also impact renewables.

[2] *This excludes projects that have that have a planned capacity of less than 1 MW.*

The primary goal of this report remains, however, the reporting of the constituent drivers of renewable power generation projects that enable an assessment of the levelised cost of electricity (LCOE)[3] and its underlying influences. 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 technology chapters therefore include:

- total installed costs (including cost breakdowns, when available) that represent the total cost of completing a project (*e.g.* including project development costs, grid connection, equipment, installation, civil engineering, contingency, etc.);

- capacity factors, calculated as the ratio of annual generation relative to the theoretical continuous maximum output of the plant, expressed as a percentage;

- operations and maintenance costs (O&M); and

- the LCOE.

Annex I discusses in more detail the metrics used, the boundary conditions for cost calculations and the key assumptions taken in relation to the weighted average cost of capital, project economic life and O&M costs.

These varied metrics allow IRENA not only to 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 a technology's generation profile means that its value is higher or lower than the average market price. As an example, CSP with thermal energy storage has the flexibility to target output during high cost periods in 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, in some markets, hydropower and CSP with storage could earn significant revenue 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, along with 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 that is optimal in minimising overall system costs, while meeting overall demand, minute-by-minute, over the year. This should be taken into account when interpreting the data presented in this report.

[3] *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.*

Other key points regarding the data presented in this report that should be borne in mind at all times are:

- All project data is for the year of commissioning, sometimes referred to as the 'commercial operation date' (COD).[4] In some cases this means a project connected to the grid may not qualify for inclusion if no meaningful generation occurs.[5] Lead times are important, with planning, development and construction sometimes taking one to three years, or more if legal challenges occur, for solar PV and onshore wind; while it can take five years or more for CSP, fossil fuels, hydropower and offshore wind.

- All monetary values are in real, 2021 US dollars (USD) – that is to say, taking into account inflation.

- Results for LCOEs are calculated using technology and country-specific benchmark values for 100 countries from IRENA's weighted average cost of capital (WACC) benchmark tool. This has been calibrated with the results of the IRENA, IEA Wind Task 26 and ETH Zurich cost of finance survey (forthcoming). For countries not covered by the WACC benchmark tool, simpler assumptions about the real cost of capital have been made for the Organisation of Economic Co-operation and Development (OECD) countries and China on the one hand, and the rest of the world on the other. See Box 1.1 and Annex I for more details.

- Capacity factor data are project developers' estimates of the average lifetime yield of projects, or where this data is not available, estimates by IRENA based on the technology and project location. The capacity factor is for newly commissioned projects in a given year, not the stock of installed capacity.[6]

- All total installed cost data and LCOE calculations exclude the impact of any financial support available to them.

- All data presented here are for the year of commissioning and are for new capacity added.

- All data contained within this report is for utility-scale projects of at least 1 MW.

- All capacity data is from IRENA's capacity statistics (IRENA, 2022a).

- Data for costs and performance for 2021 is preliminary and subject to change.

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[4] *It is worth noting that bottom-up benchmark analyses undertaken by other organisations and institutions (e.g. BNEF, IEA, Lazrad, etc.) may refer to costs at the time a financial investment decision is made. There is therefore potentially a significant time difference between IRENA estimates and others. For instance, the cost of a onshore wind project for Q1 of a year based on financial investment decision might appear as a commissioned project cost point 6-18 months later, or even longer in some cases. It is of course more complicated than this, as actual costs depend on when equipment and EPC contracts are signed.*

[5] *This is occasionally an issue where contract requirements or support policies use grid connection as the basis for meeting contract terms or qualifying for support.*

[6] *The data is therefore not a measure of the specific annual capacity factor of each year for each project, which depends on the relative wind resource in a given year. Project-specific actual generation data by year is available in some countries, but is not universally available and therefore not reported by IRENA.*

SOLAR PV AND WIND POWER COSTS FALL AGAIN IN 2021

The emerging supply chain challenges and rising commodity costs in 2021 did not result in higher total installed project cost data for projects commissioned in 2021 due to the lag between equipment cost increases appearing in commissioned projects. As a result of this and due to falling costs in China, the global weighted average cost of electricity from utility-scale solar PV, onshore and offshore wind projects commissioned in 2021 all fell.

In terms of onshore wind projects, the global weighted average LCOE of those commissioned in 2021 fell by 15%, year-on-year, (Figure 1.1), from USD 0.039/kWh in 2020 to USD 0.033/kWh. China was once again the largest market for new onshore wind capacity additions in 2021, although its share of new deployment fell to 41%, resulting in markets with higher installed costs increasing their share relative to 2020. Excluding China, the LCOE fell 12% year-on-year in 2021 to USD 0.037/ kWh.

In China, over-capacity among Chinese wind turbine manufacturers and the end of some subsidies saw project developers aggressively negotiate lower turbine prices, in contrast to the trend elsewhere. Outside of China, seven of the top 25 wind markets saw their weighted average total installed costs rise. The increased market share in 2021 of countries with very good-to-excellent wind resources – notably Argentina, Brazil, Canada, Chile, Norway, Türkiye, Sweden and the United States[7] - saw a sharp increase in the global weighted average capacity factor of newly commissioned onshore wind farms in 2021. The global weighted average capacity factor increased from 36% in 2020 to 39% in 2021 for newly commissioned projects.

The lower total installed costs for onshore wind in China and a range of other important markets in 2021, as well as the sharp increase in capacity factors, meant the global weighted average LCOE of onshore wind fell.

For utility-scale solar PV, in 2021, the global weighted average LCOE of newly commissioned projects fell by 13%, year-on-year, from USD 0.055/kWh to USD 0.048/kWh. This was driven by a decline in the global weighted average total installed cost for this technology of 6%, from USD 916/kW in 2020 to USD 857/kW for the projects commissioned in 2021. This was less than the 12% decline experienced in 2020, as rising PV module prices at the end of 2020 appear to have had some impact on total costs for a significant number of projects. Overall, the impact was muted, however, with only three markets in the top 25 for new installations in 2021 seeing their country-level weighted average total installed costs increase. It is notable that the increased total installed costs occurred in very competitive markets, such as Spain, where developer margins are extremely thin and project costs proportionately more exposed to materials and equipment price increases.

[7] *In 2021, these countries combined accounted for one-third of new deployment.*

The 13% reduction in LCOE in 2021 for utility-scale solar PV was higher than the 11% decline recorded in 2020. This was because the global weighted average capacity factor of new projects in 2021 returned to a figure above 17%.[8] This was driven partly by some changes in the share of deployment in areas with better solar resources, compared to 2020, while it was also due to the increasing use of single axis trackers and bifacial PV modules.

Similar to the situation for onshore wind, China was the largest market for new capacity added in utility-scale solar PV, accounting for an estimated 35% of the global total in 2021.

The offshore wind market, which added 6 GW in 2020, saw unprecedented expansion in 2021, with 21 GW added. China increased its new capacity additions by a factor of 5.7 over an already-record 2020 expansion, adding 17.4 GW in 2021. This deployment saw the global weighted average cost of electricity of new projects fall by 13%, year-on-year, from USD 0.086/kWh to USD 0.075/kWh. This was driven by a fall in global weighted average total installed costs from USD 3 255/kW in 2020 to USD 2 858/kW in 2021, while the global weighted average capacity factor increased from 38% to 39%, restrained by the relatively poor wind resource sites, relative to elsewhere, of Chinese projects.

With China accounting for 82% of global offshore capacity additions in 2021, the story of the global offshore wind sector in 2021 is essentially one where the data reflects Chinese offshore wind market conditions in global weighted averages. Looking at the situation in Europe, the weighted average LCOE of newly commissioned projects fell 29% from USD 0.092/kWh to USD 0.065/kWh. This was driven by a 25% reduction in total installed costs year-on-year to USD 2 775/kW in 2021 and an increase in the weighted average capacity factor of new projects from 42% in 2020 to 48% in 2021. For Europe, the benefit of economies of scale in large projects, as well as supply chain and O&M optimisation over the last five years can clearly be seen. However, with long lead times, many forthcoming projects will be highly exposed to commodity price increases.[9]

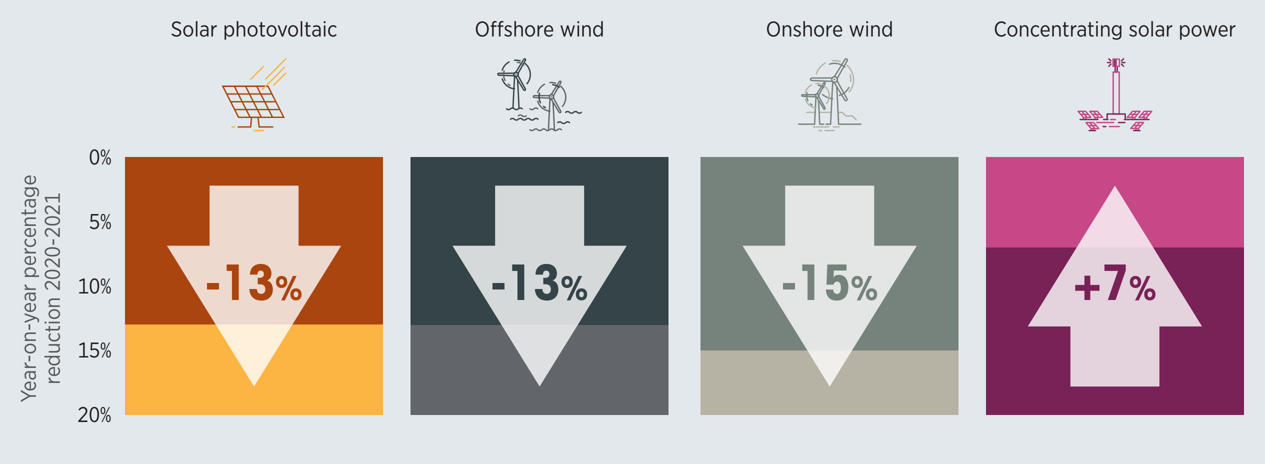
Chapter 4 provides a more nuanced view of the offshore wind sector in 2021 by market, highlighting Viet Nam, which emerged from 2021 with 1 GW of commissioned capacity.

With only one CSP plant commissioned in 2021, after two were commissioned in 2020, deployment remains limited and year-to-year cost changes volatile. Noting this caveat, the average cost of electricity from the one project was around 7% higher in 2021, year-on-year. However, given the project commissioned in 2021 was the long delayed Cerro Dominador project in Chile, this had an installed cost structure that is more indicative of projects commissioned three to four years ago and achieved a relatively competitive LCOE due to its very high capacity factor, given the world class solar resource at its site.

[8] *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 in per-watt DC, sometimes referred to as ‘per Watt peak’.*

[9] *Those with contracts for differences or PPAs that are not indexed to inflation are likely to be much more exposed and project delays or renegotiations of contract terms may be justified given the extraordinary circumstances of 2022.*

Figure 1.1 Global LCOE from newly commissioned utility-scale solar and wind power technologies, 2020-2021



Source: IRENA Renewable Cost Database.

The cost declines seen in 2021 may not be repeated for solar PV and wind power in 2022, as supply chain constraints have been having an impact since late 2020, while commodity price rises accelerated in late 2021. These two factors saw equipment prices increase after experiencing lows in the first half of 2020, when the pandemic first took hold.

Yet, as noted above, the impact of these factors on projects commissioned in 2021 was not enough to raise the full year weighted average LCOE in many individual markets, nor at a global level.[10] That is not to say that individual projects commissioned towards the end of 2021 did not experience higher costs than in 2020, but that on average the cost of electricity for all projects in 2021 were still lower than in 2020. Although there are limits to what can be extrapolated from IRENA's data, this is likely to be predominantly explained by five key factors:

- Overall equipment cost increases were modest in late 2020 and into early 2021, when many projects commissioned in 2021 would have placed their orders.

- Larger projects have greater purchasing power and longer lead times, blunting price increases and delaying the impact of price hikes on commissioned projects. Such larger projects are also increasingly dominating capacity additions outside Europe.

- Contingency allowances in most projects will have absorbed some or all of any increased costs.

- Technology improvements (*e.g.* more efficient PV modules and larger wind turbines) and improvements in manufacturing efficiency and scale continue, reducing the impact of commodity price increases.

[10] *Global weighted averages can vary without any underlying costs changes, where different markets have structurally different costs. Assuming no cost or performance changes, the global weighted average cost can change if the share of new capacity in 'high' or 'low' cost markets changes.*

- China remains the dominant market for new solar and wind capacity additions and has lower commodity prices and transport costs, while in 2021, its local market/policy dynamics also favoured lower pricing – at least for onshore wind.

There are additional factors at play for some technologies and markets and these will be discussed in more detail in the specific technology chapters.

Looking in more detail at the trends in equipment costs, it becomes more apparent why the first two bullet points in the above list are important. After lows in mid-2020, solar PV module and wind turbine pricing had already started to increase, if modestly initially, and was followed by a sustained rise in 2021.

In 2020, delivered wind turbine prices outside of China increased by a modest 0% to 3% over the year, with a further 1% to 11% increase in 2021 – albeit with Class I turbines experiencing a decline in price that year (BNEF, 2022). In 2020, the average sales price of Vestas' order intake in USD terms fell 9%, year-on-year, but rose by 16% in 2021, returning the price to levels not seen since Q4 2017. With lead times for orders of 7 to 12 months, the impact of these order price rises will be more keenly felt in total installed costs in 2022. The experience in China, however, has been quite different, with an end to subsidies there seeing developers aggressively negotiate lower prices in 2021. The result was that Chinese wind turbine prices rose 8% over the year in 2020, then fell by 28% or more in 2021 (BNEF, 2022 and Wood Mackenzie, 2022).

In December 2020, solar PV module prices were broadly unchanged from one year earlier for 'all black', 'high-efficiency' and 'mainstream' modules (pvXchange, 2022). At the same time, the prices of 'low cost' modules were 9% lower, those of bifacial modules 11% lower, and thin-film modules 23% lower. As supply chain constraints and polysilicon shortages relative to growing demand became apparent, the price of polysilicon increased from a low of USD 7/kg in June 2020 to over USD 30/kg by the end of 2021 as cell manufacturers rushed to secure supplies. With industry expansion efforts, prices have recently stabilised for polysilicon, but module prices increased by between 5% and 14% over the year for 2021 for all types, with the exception of 'low cost' modules, where prices were broadly flat. With modules typically accounting for between 30% and 40% of total installed costs, these price increases were, however, to some extent, diluted in total installed costs. The impact of freight and commodity price increases on other hardware costs (*e.g.* on the copper in cabling, or the steel and aluminium used in racking and mounting) were also muted in 2021, but there may be more pass-through of these costs in 2022 if commodity prices remain elevated. These trends are discussed in more detail in the following sections.

After lows in mid-2020, solar PV module and wind turbine pricing started to increase modestly, followed by a sustained rise in 2021

COST TRENDS, 2010-2021

The period 2010 to 2021 saw a seismic shift in the balance of competitiveness between renewables and incumbent fossil fuel and nuclear options. The discussion has gone from one of how long it will take for renewables to become competitive to one where stakeholders around the world are identifying ways to integrate the maximum amount of solar and wind power possible into their electricity systems. As the fossil fuel price crisis continues, solar and wind – with their relativity short project lead times – represent vital planks in countries' efforts to reduce their exposure to fossil fuels and limit the economic and social damage these fuels are causing. This is not to mention renewables' additional environmental benefits in terms of reduced local pollutants and carbon dioxide (CO_2) emissions.

In 2010, onshore wind was the only solar or wind technology to fall within the cost range of new fossil fuel-fired power generation[11] options in the G20. During the period from then until 2021, CSP, offshore wind and utility-scale solar PV all also joined the range of costs for new capacity fired by fossil fuels. This analysis excludes any financial support for renewable technologies, so the economic case for the consumer or project developer is often more compelling.

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 2018, the global weighted average LCOE of onshore wind fell below the level of the cheapest new fossil fuel-fired electricity generation option in the G20, while solar PV achieved that feat in 2020. It is not just in new capacity that solar PV and onshore wind are competitive, however; they are also increasingly cheaper than even the marginal operating costs of existing fossil fuel plants using coal and fossil gas. This was also the case even before the current fossil fuel price crisis.

Since 2010, solar PV has experienced the most rapid cost reductions, with the global weighted average LCOE of newly commissioned utility-scale solar PV projects declining by 88% between 2010 and 2021, from USD 0.417/kWh to USD 0.048/kWh (Figure 1.2). This cost reduction occurred as global cumulative installed capacity of all solar PV (utility scale and rooftop) increased from 40 GW to 843 GW. This represented a precipitous decline, from a level more than twice that of the most expensive fossil fuel-fired power generation option to a level in 2021 that undercut by USD 0.008/kWh the bottom of the range for new fossil fuel-fired capacity in the G20.[12]

This reduction has been primarily driven by declines in module prices which have – despite the recent uptick – fallen by 91% since 2010. This has been driven by module efficiency improvements, increased manufacturing economies of scale, manufacturing optimisation and reductions in materials intensity.

[11] This excludes the cost of CO_2 emissions in jurisdictions where a meaningful price is applied to ensure a direct comparison across fossil fuel options in different countries.

[12] The fossil fuel-fired power generation cost range by country and fuel for the G20 is estimated to be between USD 0.054/kWh and USD 0.167/kWh. This assumes the current fossil fuel price crisis doesn't cause a fundamental shift in 30-year fossil gas price expectations. If long-term US gas price expectations rose to USD 5/gigajoule (GJ) at the Henry Hub, the lower bound would rise to USD 0.064/kWh.

Total installed costs have also declined due to reductions in balance of system costs, helped by module efficiency improvements and a host of other factors, as documented in Chapter 3. As a result, the global weighted average total installed cost of utility-scale solar PV fell by 82% between 2010 and 2021, from USD 4 808/kW to just USD 857/kW in 2021.

Utility-scale solar PV capacity factors have also risen over time. Initially, this was driven predominantly by 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 also played a small but important role in this, but in recent years, it is the increased use of trackers and bifacial modules – which increase yields for a given resource – that has played a more significant role.[13]

Between 2010 and 2021, the global weighted average cost of electricity for onshore wind projects fell by 68%, from USD 0.102/kWh to USD 0.033/kWh. This decline occurred as cumulative installed capacity grew from 178 GW to 769 GW. Cost reductions for onshore wind were driven by falls in turbine prices and balance of plant costs, as the industry scaled-up, average project sizes increased (notably outside Europe), supply chains became more competitive, and the cost of capital fell (including the technology premium for onshore wind); as well as the higher capacity factors achieved by 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, and improved preventative maintenance programmes. Improvements in technology have also resulted in more reliable turbines, with increased availability. At the same time, higher capacity factors mean that the fixed O&M costs per unit of output have fallen even faster than the fixed O&M costs measured as USD/kW/year.

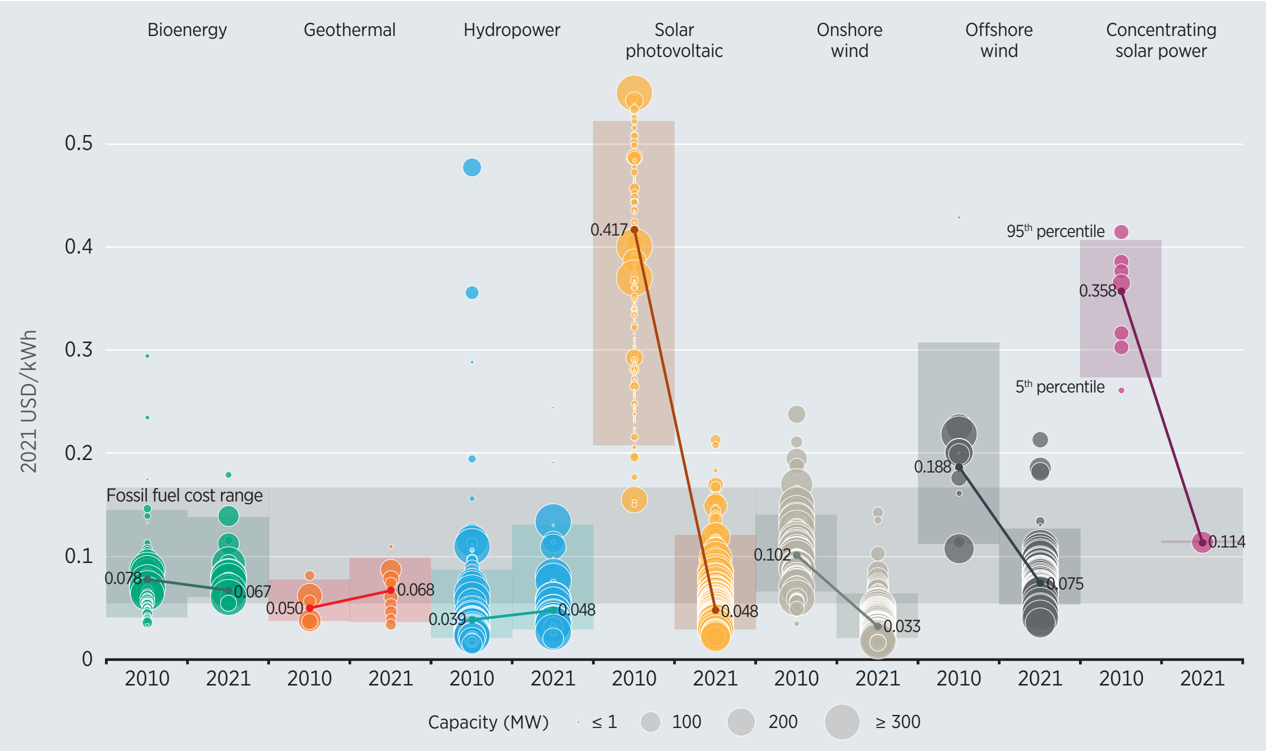
The global weighted average total installed cost of newly-commissioned onshore wind projects fell from USD 2 042/kW in 2010 to USD 1 325/kW in 2021, a decline of 35%. At the same time, continued improvements in wind turbine technology, wind farm siting and reliability have led to an increase in average capacity factors, with the global weighted average of newly commissioned projects increasing from 27% in 2010 to 39% for those commissioned in 2021. 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.

Compared to 2020, there was also a significant increase in the global 2021 weighted average capacity factor. In 2021, the share of new deployment in China declined and that of areas with excellent wind resources rose. The technology improvement since 2010 is greater than that implied by the increase in the global weighted average capacity factor too, because, on average, major markets in 2020 – and, likely, in 2021 – were deploying in areas of poorer wind resources than in 2010 (see Chapter 2 for more details).[14]

[13] *Unfortunately, project-level data on the use of trackers and module types is less comprehensive and its availability is subject to a greater time lag than for project costs, meaning the overall impact is difficult to quantify.*

[14] *The analysis of the change in wind speed quality is based on a sub-set of projects in the IRENA Renewable Cost Database, so some caution should be used in interpreting these conclusions.*

Figure 1.2 Global weighted average LCOEs from newly commissioned, utility-scale renewable power generation technologies, 2010-2021



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 LCOE is calculated with project-specific installed costs and capacity factors, while the other assumptions are detailed in Annex I. 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.

The offshore wind sector experienced unprecedented growth in 2021. While Europe added around 3 GW of new capacity – a figure similar to 2020's additions – China added an unprecedented 17.4 GW. Between 2010 and 2021, the global weighted average LCOE of newly commissioned offshore wind projects declined from USD 0.188/kWh to USD 0.075/kWh, a reduction of 60%. Over the same period, the global weighted average total installed costs of offshore wind farms fell 41%, from USD 4 876/kW to USD 2 858/kW.

With relatively modest capacity additions each year prior to 2021, however, annual values for global weighted average total installed costs, capacity factors and LCOEs had been relatively volatile, over the years. More recently, growth in new markets – both within Europe, where offshore wind markets first developed, and globally – have also added more 'noise' to the data. Yet, in the last two years, with China accounting for 50% of new capacity additions in 2020 and 82% in 2021, the global-weighted average cost and performance metrics have therefore increasingly represented Chinese circumstances.[15]

[15] *See Chapter 4 for a more nuanced discussion that presents how the cost and performance metrics for offshore wind have evolved in individual markets in Europe, China and elsewhere.*

This is particularly true for the evolution of the global weighted average capacity factor of newly commissioned offshore wind farms, which rose to between 42% and 43% between 2015 and 2019, but declined to 38% in 2020 and 39% in 2021. This was not due to any regression in technology performance or poorer resources in individual markets, but due to the poorer resources and smaller turbines used by China in their near-shore and inter-tidal developments along China's coastal zones. With modest wind resources in comparison to Europe and elsewhere, China's overwhelming share in global deployment in 2020 and 2021 saw the global weighted average capacity factor settle at around 38% to 39%.

Regarding CSP, over the period 2010 to 2021, its global weighted average cost of electricity fell from USD 0.358/kWh to USD 0.114/kWh – a decline of 68%. After two projects came online in 2020 – both in China – just one project was commissioned in 2021, however, the long-delayed Cerro Dominador project in Chile.

The above decline in the cost of electricity from CSP, which has placed it in the mid-cost range of new capacity from fossil fuels, remains a remarkable achievement, however, given the cumulative global capacity of just 6.4 GW, which is a 130 times smaller than the capacity of solar PV installed at the end of 2021. Similarly to solar PV, the decline in the 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. This is abundantly evident in the Cerro Dominador project, which has 17.5 hours of storage and a location that has one of the highest direct normal irradiance (DNI) resources in the whole world.[16] As a result, Cerro Dominador has an annual capacity factor of at least 80% – slightly less than twice the weighted average of the two Chinese projects commissioned in 2020.

The Cerro Dominador project also has higher total installed costs than the Chinese projects having suffered cost increases due to delays. Although the Chilean CSP plant was never expected to record Chinese cost levels, Cerro Dominador's total installed cost of USD 9 019/kW is more in line with projects developed between 2010 and 2015, than with recent ones.[17] The very high capacity factor offsets these high installed costs to a large extent, though, with the project's LCOE only slightly higher than the weighted average of the two Chinese plants commissioned in 2020.

For bioenergy, geothermal and hydropower, installed costs and capacity factors are highly project and site 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, particularly when deployment is relatively thin and the share of different countries/regions in new deployment varies significantly, year-to-year. This is true almost every year for geothermal, where new capacity additions have ranged between 140 MW/year and 655 MW/year since 2010, while – depending on the year – this wide variation can be more or less pronounced for bioenergy and hydropower.

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[16] *The DNI for the Cerro Dominador project has been estimated at 3 186 KWh/square metre (m^2)/year (SolarPaces, 2021).*

[17] *Construction of Cerro Dominador started in 2014, but after industrial action onsite and financial problems beset the project contractor, Abengoa, construction halted in 2016. EIG partners took over the project, raised the necessary financing and restarted construction in 2018.*

For 2010 to 2021 inclusive, hydropower added 333 GW of new capacity, with 19 GW commissioned in 2021. Over the same period, the global weighted average LCOE rose by 24%, from USD 0.039/kWh to USD 0.048/kWh. This was still lower than the cheapest new fossil fuel-fired electricity option, despite the fact that costs increased by 5% in 2021, year-on-year. With the global weighted average capacity factor largely unchanged at 44% to 45% between 2010 and 2021, this LCOE increase has been predominantly driven by the 62% increase in total installed costs per kW over that period (10% year-on-year in 2021). This occurred as developments increasingly shifted to projects in less ideal areas, further from existing infrastructure and/or with challenging conditions that have higher development costs.

Between 2010 and 2021 inclusive, 72 GW of new bioenergy for power capacity was added, including the 9 GW added in 2021. The global weighted average LCOE of bioenergy for power projects experienced a certain degree of volatility during this period, but without a notable trend upwards or downwards. In 2021, however, bioenergy's global weighted average LCOE of USD 0.067/kWh was 14% lower than the 2010 value of USD 0.078/kWh, given that this value was at the upper end of the range of USD 0.055/kWh to USD 0.082/kWh experienced by the global weighted average for the period.

The global weighted average LCOE of geothermal was USD 0.068/kWh in 2021, 34% higher than in 2010, but well within the range seen between 2013 and 2021, of USD 0.054/kWh to USD 0.071/kWh. Annual new capacity additions remain modest, allowing one project with an atypically low capacity factor – 42% – to drag down the global weighted average capacity factor of projects commissioned in 2021 to 77%.

RENEWABLE POWER: THE COMPETITIVE SOLUTION FOR NEW CAPACITY

Between 2001 and 2021, CSP, offshore wind and utility-scale solar PV all joined onshore wind within the cost range of new, fossil fuel-fired capacity, when calculated without the benefit of financial support. Indeed, the data suggest that since 2018, the trend is not only one of renewables competing with fossil fuels, but significantly undercutting them when new electricity generation capacity is required. In areas with excellent solar and wind resources, we are also seeing an increasing number of projects undercutting even the marginal operating costs of coal and fossil gas-fired power plants – even before the latest fossil fuel price crisis is factored in.

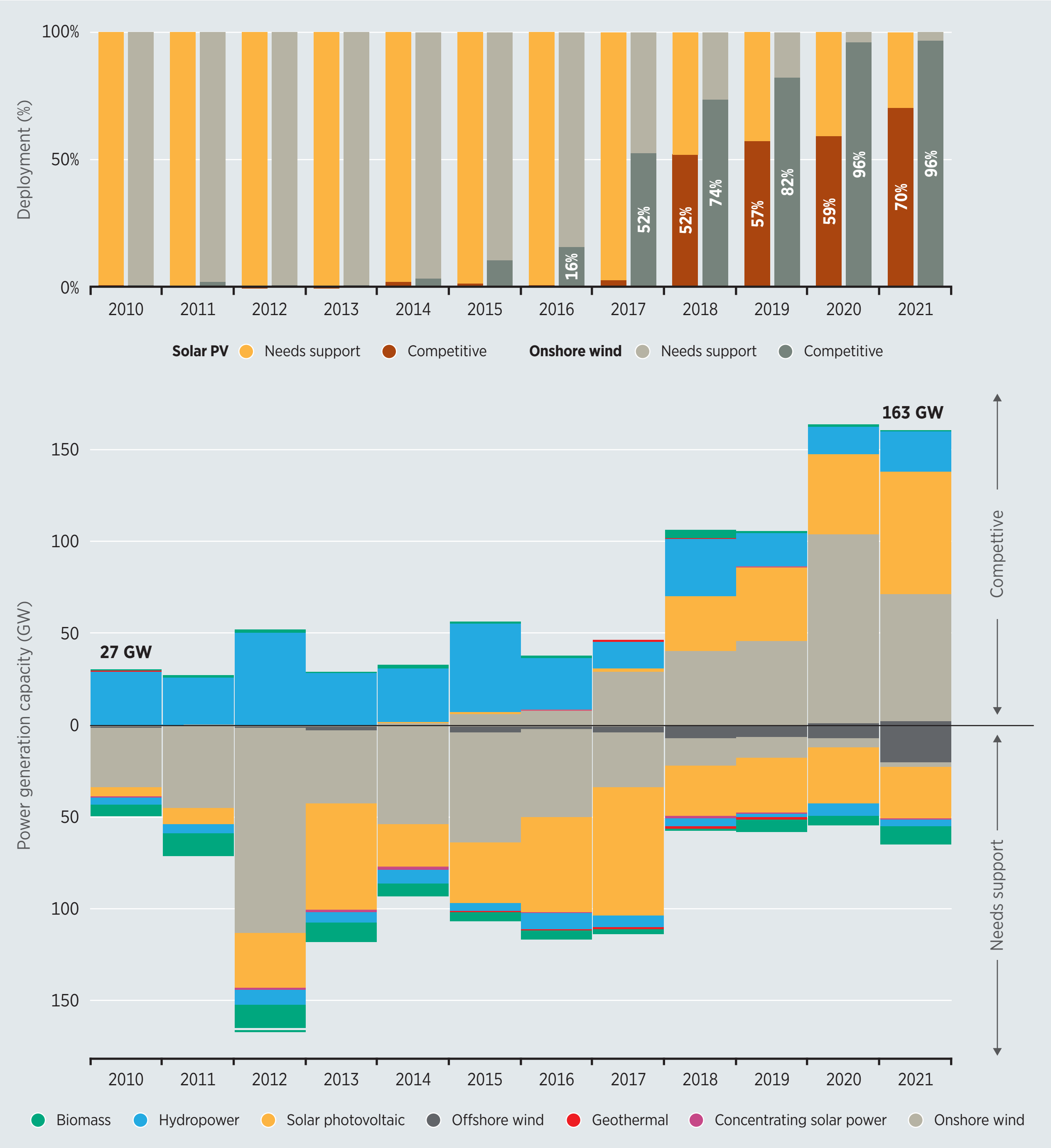
In 2021, around 73% (163 GW) of newly commissioned, utility-scale[18] renewable power generation capacity had costs of electricity lower than the cheapest fossil fuel-fired option in the G20 (Figure 1.3).[19] This is only slightly lower than the estimate for competitive renewable electricity capacity[20] deployed in 2020.

[18] This includes all projects with a capacity of 1 MW or more and includes IRENA's assessment of 95 GW of new utility-scale solar PV deployment in 2021.

[19] As previously noted in 2021, the lower bound of USD 54/megawatt hour (MWh) (USD 0.054/kWh) is set by a combined-cycle gas turbine in the United States, assuming a lifetime fossil gas cost of USD 3.6/GJ.

[20] For the purposes of the analysis presented in this section and Figures 1.3 and 1.4, 'competitive' in this context is defined as individual renewable power generation projects having an LCOE lower than the cheapest fossil fuel-fired power generation option in the G20, by year.

Figure 1.3 Annual and cumulative total new renewable power generation capacity added at a lower cost than the cheapest fossil fuel-fired option, 2010-2021



Source: IRENA Renewable Cost Database.

Note: All capacity above zero in this figure represents projects with a lower LCOE than the cheapest fossil fuel-fired new generation option, at USD 54/MWh for a CCGT in the United States, and all capacity below the zero line had higher costs than this.

In 2021, 69 GW of the onshore wind projects commissioned had electricity costs that were lower than the cheapest fossil fuel-fired option. This was an amount lower than the figure of 103 GW recorded in 2020, due to the decline in new capacity additions in China in 2021, but represents an almost identical percentage of global new onshore wind capacity additions (96% in both years).

The continued decline in the costs of solar PV also meant that in 2021 a record 67 GW of utility-scale solar PV projects commissioned had lower costs than the cheapest fossil fuel-fired option, up from 44 GW in 2020 and 40 GW in 2019.

The year 2018 was also a seminal one for onshore wind and utility-scale solar PV, as it was the first year when both technologies saw over half of their new capacity additions register below the cost of the most competitive new fossil fuel-fired option. For wind, this breakthrough had been building up over the three previous years, but for solar PV, it was a more rapid result. To some extent, this highlighted the more homogeneous nature of the competitive cost structure for solar PV (although, despite this, wide discrepancies in installed cost for solar PV still exist) when compared to onshore wind, given larger variations in the latter's installed costs (per kW) and capacity factors in mature markets.[21]

In 2021, too, for the first time, significant offshore wind capacity was estimated to have a lower cost of electricity than the cheapest fossil fuel-fired costs, with 2.3 GW in total – all outside of China – and 1.8 GW of that capacity in Europe. Although this total was only 11% of 2021's total global new capacity additions, given a surge in Chinese deployment that year, the 2.3 GW represented around 60% of global new capacity additions outside of China. This is a sign of future deployment trends, as the increasing number of projects that have been procured at very competitive prices in auctions and tenders comes online in the next few years.

For hydropower, in 2021, 22 GW of the projects commissioned had costs that were less than the lowest-cost fossil fuel-fired power generation option. In geothermal and bioenergy, around 440 MW of power plants also had an LCOE lower than the cheapest new fossil fuel-fired capacity option that year.

In total, between 2010 and 2021, 786 GW of renewable power generation with a lower cost than the cheapest G20 fossil fuel-fired option was deployed. The rapidly improved economics of onshore wind in recent years means that both this and hydropower represent around 300 GW each of the total, with an additional 183 GW from utility-scale solar PV.

In markets where electricity demand is stagnant or falling, new renewables projects need to be able to earn sufficient revenue to match their lifetime costs. In this case, it is not new fossil fuel plants against which they are being benchmarked, but the revenue gained in these markets. In that respect, reform of electricity market structures is essential and increasingly urgent, if electricity markets are to be fit for a future dominated by large shares of variable renewables, rather than the current paradigm of the past based on an electricity system built around large, centrally despatched power stations.[22]

In 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.

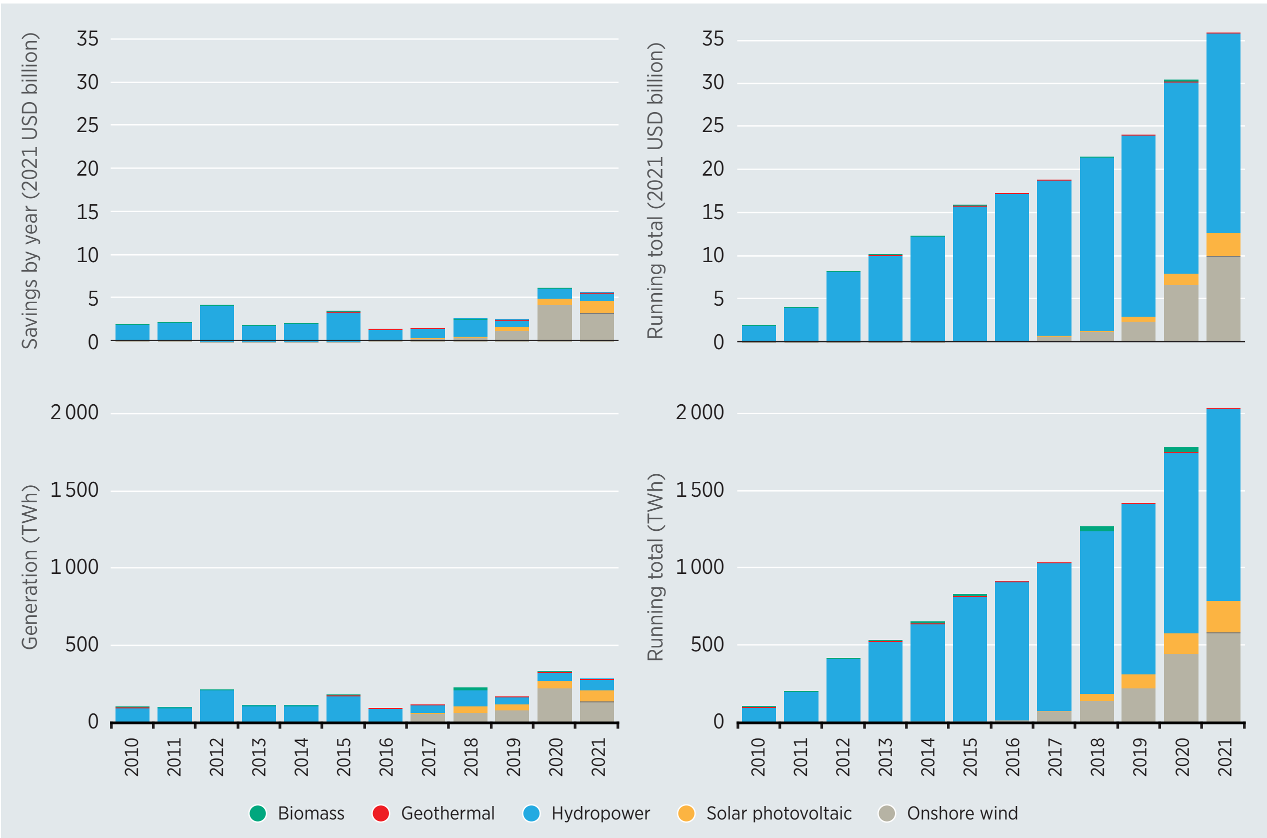
[21] *Having noted this, it is also noticeable that there has been a convergence in what a competitive installed cost structure looks like for onshore wind in recent years – setting aside, as always, China and India, which have quite different and generally lower cost structures.*

[22] *See* RE-organising power systems for the transition *for a discussion of this topic (IRENA, 2022b).*

In 2022, in non-OECD countries, the 109 GW of projects with costs lower than the cheapest fossil fuel-fired cost option will reduce costs in the electricity sector by at least USD 5.7 billion annually (Figure 1.4, left hand side), relative to the long-term cost of adding the same amount of fossil fuel-fired generation. The majority of these savings – a total of USD 3.4 billion – will come from onshore wind. Hydropower, with its higher capacity factors, contributes around USD 1 billion to these savings, with utility-scale solar PV accounting for most of the remaining USD 1.3 billion. The cumulative undiscounted savings of the new projects deployed in 2021, over their economic lives, will reach at least USD 149 billion. In addition to these direct cost savings, too, the substantial economic benefits of reducing carbon dioxide emissions and local air pollutants also need to be factored in, when considering the total benefits.

Between 2010 and 2021, inclusive, globally, around 635 GW of renewable power generation capacity has been added in non-OECD countries that had costs lower than the cheapest fossil fuel-fired option in that year.[23] Of this total, 294 GW is hydropower (46%), 189 GW onshore wind (30%) and 142 GW (22%) utility-scale solar PV. In 2022, this 635 GW will reduce electricity system costs by at least USD 36 billion (Figure 1.4, right hand side). With the highest capacity factor, it is hydropower that dominates the savings, contributing USD 23 billion, or 64% of the total. With USD 9.7 billion in savings annually, onshore wind is the second largest contributor, followed by solar PV, with USD 2.7 billion annually (7.5% of the total).

Figure 1.4 Annual and cumulative savings and generation from new renewable power generation capacity with lower costs than the cheapest fossil fuel-fired option, non-OECD countries, 2010-2021



Source: IRENA Renewable Cost Database.

[23] *Assuming that the cheapest fossil-fuel fired option in the G20 group of countries was a Chinese coal plant in 2010, which had an LCOE of USD 50/MWh, and in 2021 was a US gas combined cycle plant with an LCOE of USD 54/MWh.*

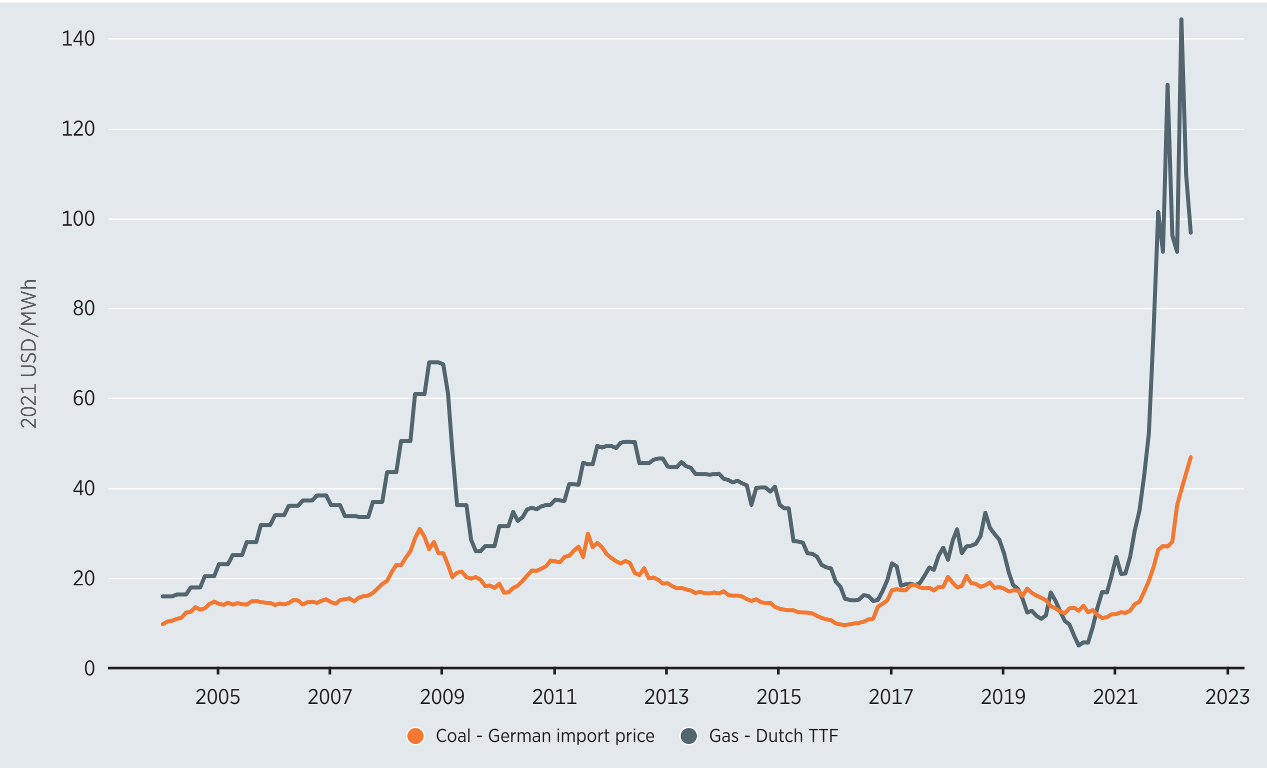
RISING FOSSIL FUEL PRICES IN 2022 HIGHLIGHT THE BENEFITS OF RENEWABLE POWER

Fossil gas prices in Europe averaged 4.9 times more in the period January to April 2022 than in the same period of 2021. At the same time, steam coal prices in Germany were 2.8 times higher in Q1 2022 compared to the same period the year before (Figure 1.5). The surge in European fossil gas prices is unprecedented. The monthly average price has stayed above USD 90/MWh since October 2021, with a record average of USD 145/MWh in March given the situation with gas supplies to Europe from Russia as a result of the war in Ukraine. This is 47% higher than the previous record monthly average fossil gas price of USD 68/MWh, set between October 2008 and January. Even this record may not last, with prices spiking again at the end of June and beginning of July 2022.

Thermal coal prices have risen less, but still by an eyewatering factor of 2.8, year-on-year, over January 2021 levels. The average price paid in Germany for thermal coal imports in March 2022 surpassed the USD 300/tonne mark for the first time, equating to a cost of USD 40/MWh. Traded futures prices dropped slightly in April from this high, but returned to similar levels in and have risen again in late June and early July to around USD 350/tonne.

With wholesale electricity markets driven by the marginal cost of the most expensive bid, fossil gas has typically been setting the marginal price during the working week, although on weekends and periods of very high renewable power generation this is not always the case.

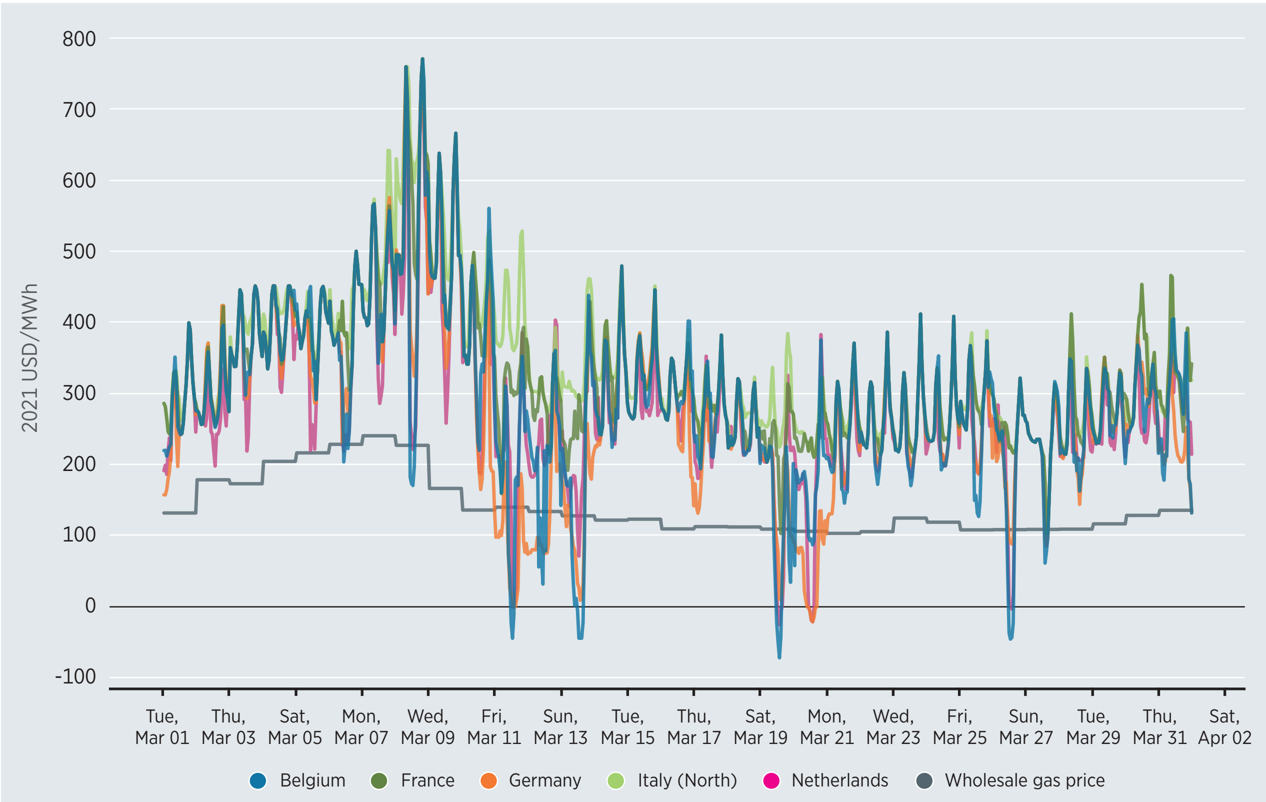
Figure 1.5 European fossil gas and thermal coal price trends by month, 2004-2022



Source: IRENA Renewable Cost Database.

Figure 1.6 presents hourly wholesale electricity market prices and wholesale fossil gas prices, showing their extremely elevated levels. The simple average wholesale price[24] for the month of March 2022 was USD 343/MWh in northern Italy, USD 325/MWh in France, USD 293/MWh in Belgium, USD 288/MWh in the Netherlands and USD 278/MWh in Germany. That same month, the fossil gas price averaged USD 145/MWh. In March 2022, wholesale electricity prices in these markets were 4.8 to 5.4 times higher than in the same month in 2021, when wholesale electricity prices averaged between USD 55/MWh and USD 72/MWh in these countries.

Figure 1.6 Wholesale electricity (hourly) and fossil gas (daily) prices for Belgium, France, Germany, Italy and the Netherlands, March 2022



Source: German Federal Network Agency (Bundesnetzagentur), 2022.

The situation in 2022 provides a stark example of just how economic new renewable power generation has become and the benefits it has in insulating economies from volatile fossil fuel prices. Figure 1.7 presents the marginal, fuel cost only,[25] possible generating cost for fossil gas-fired and coal-fired power plants in a range of different markets for 2022[26] and compares them to the weighted average full lifecycle cost (LCOE) of new solar and wind power plants commissioned in 2021.

[24] *With lower prices typically falling on weekends or other periods of low demand, a weighted average based on volume would yield somewhat higher prices.*

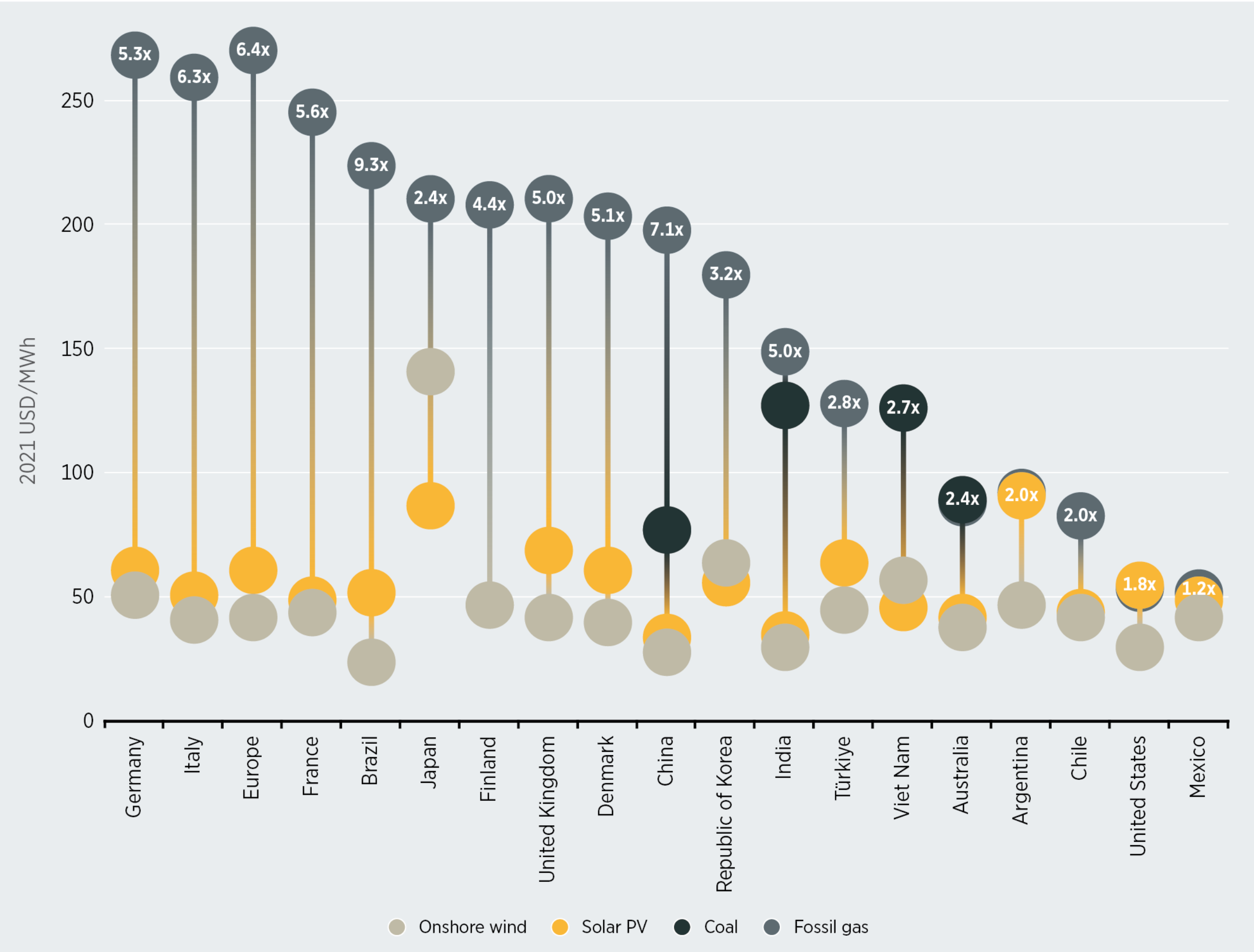
[25] *This is the 'as generated' value, not the wholesale cost of fossil gas (i.e. after allowing for the efficiency of the power plant generation).*

[26] *See Annex I for a discussion of the methodology and data sources. Actual wholesale fossil fuel price data is used for the period January 2022 to April/May 2022, with estimates for the remainder of that year. The data for Europe also includes the impact of the EU ETS prices, assumed to average EUR 90/tonne in 2022.*

Based on the data available up to May 2022, IRENA estimated that the average fuel-only cost for fossil gas-fired power plants in 2022 might range from a low of USD 50/MWh in Mexico to a high of USD 268/MWh in Germany. For coal-fired generation, the marginal cost could range from a low of USD 77/MWh in China, to a high of USD 127/MWh in India. In all cases, there is significantly more upside risk to these numbers than downside given the continued war in Ukraine and the lack of urgency in 2022 in accelerating renewable power deployment and energy efficiency options.

Another way of considering just how competitive renewables are in 2022 is to look at the revenue raising potential of the solar and wind capacity added in 2021, relative to the implied capital recovery requirement[27] in 2022, when based on WACC and economic lifetime assumptions (see Annex I). Figure 1.8 presents the results of this analysis for 17 countries for onshore wind and a subset for offshore wind and utility-scale solar PV. The analysis assumes that solar and wind projects generating in 2022 can capture: the annual marginal fuel only; fossil gas-fired electricity generation cost estimate by country; or, in some cases, the marginal coal-fired generation cost.[28]

Figure 1.7 Fuel-only generation costs for coal and fossil gas for 2022 relative to the LCOE of new solar PV, onshore and offshore wind power projects commissioned in 2021, by country



Sources: See Annex I.

[27] The capital recovery requirement is an annuity based on the WACC and economic lifetime of a project and yields the fixed annual payment that would be required to both repay the original capital investment and provide the rate of return to the owners specified in the WACC.

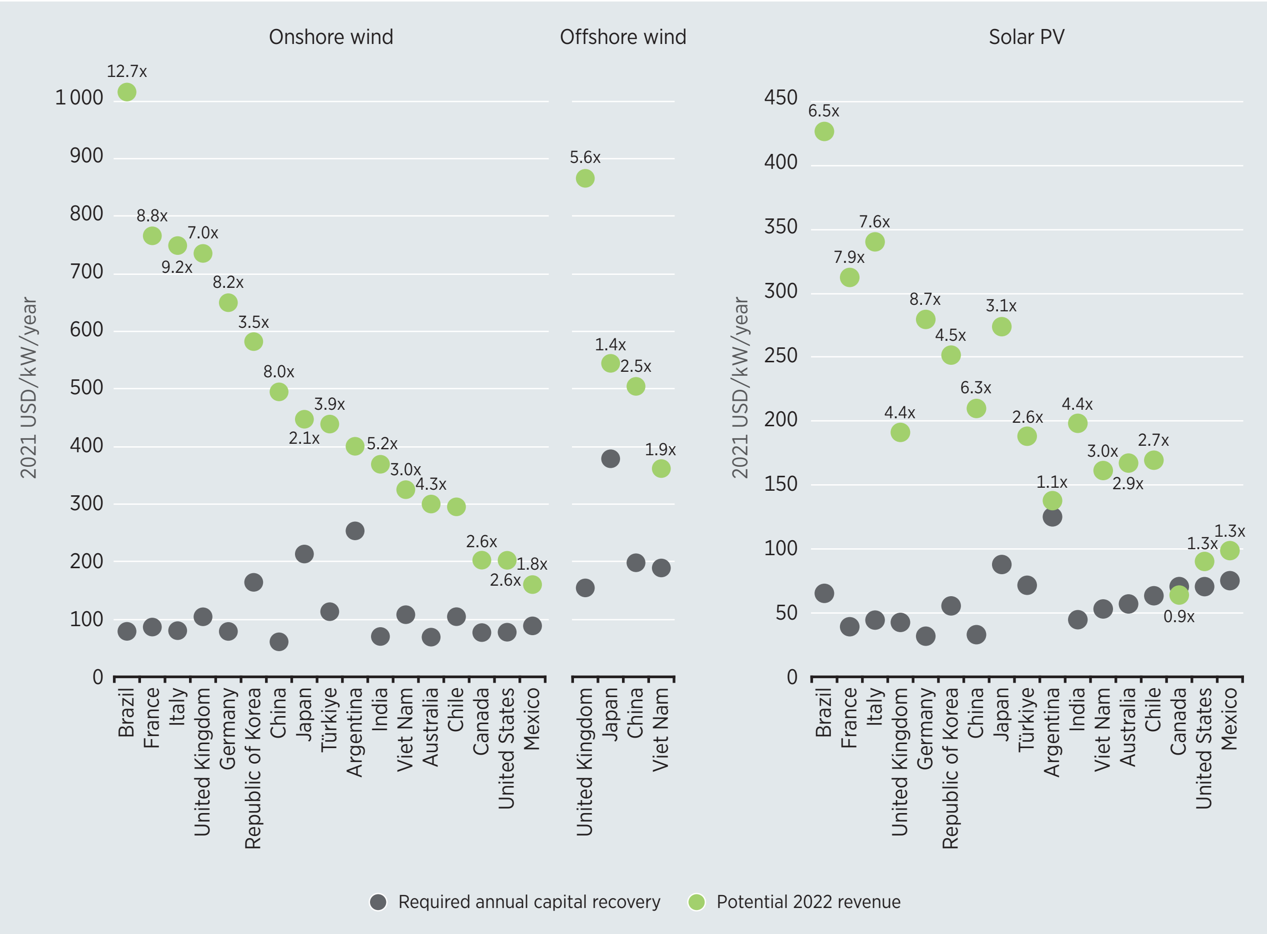
[28] This is a measure of the economic value of the avoided generation by renewables in 2022. It might not be possible for the projects themselves to capture this value, as it depends on the electricity system structures, but provides an order of magnitude estimate of the societal benefit.

At an extreme, if a wind power project commissioned in Brazil in 2021 could capture the marginal gas-fired electricity generation cost of Brazil this year, the project would recover the equivalent of 12.7 years of capital in 2022 alone. This is equivalent to around half of the total required repayments to capital of a project with a 25 year economic life in one year.

In Europe, that ratio for onshore wind ranges from 7 years in the United Kingdom to 9.2 years in Italy. For offshore wind, with its higher installed costs than onshore wind, the ratio is smaller for the countries with data, but might range from a low of 1.4 times the normal annual return in Japan to as much as 5.6 times in the United Kingdom.

The results for solar PV are more mixed, given the higher costs in many markets compared to onshore wind. In Europe, however, the solar PV projects commissioned in 2021 could recover between 4.4 times (in the United Kingdom) and 8.7 times the normal expected capital in 2022, if they can capture the marginal fossil gas-fired electricity price.

Figure 1.8 Implied 2022 revenue for solar and wind projects commissioned in 2021, relative to their annual capital recovery requirement



Source: IRENA analysis, based on IRENA Renewable Cost Database and fuel-only gas generation costs in Figure 1.8.

Note: Revenue in this figure is based on the assumption renewables projects capture the avoided marginal gas- or coal-fired electricity generation costs in 2022.

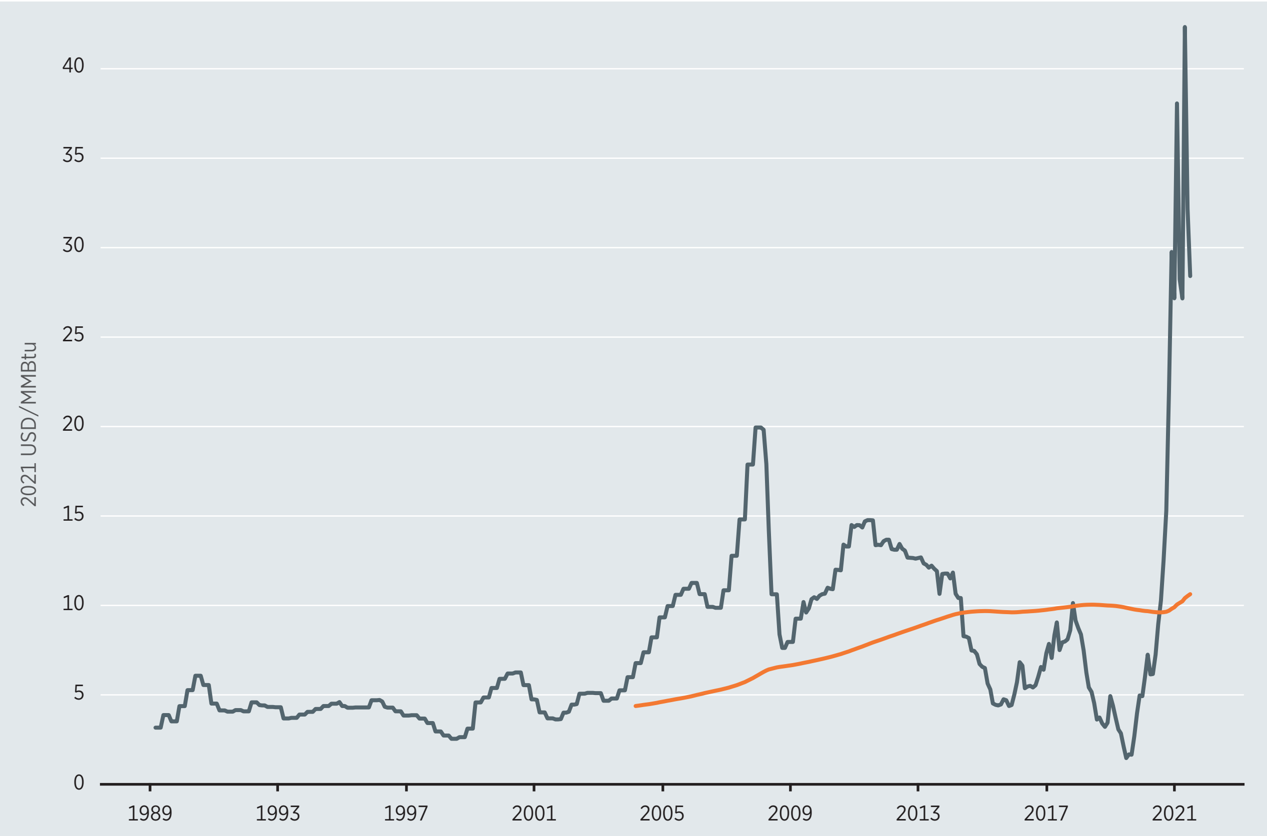
NATURAL GAS IS LOSING ITS TRANSITION ROLE IN POWER GENERATION IN EUROPE

The increase in coal and fossil gas prices in 2021 and to-date in 2022 has illuminated a trend that has been obscured by the volatility of fossil fuel prices over the last 15 years – namely, the fact that for Europe, the low-cost era of fossil gas ended in 2004.

Indeed, volatility in prices over the last 15 years – with peaks and troughs from 2008 to 2009, 2012 to 2016 and 2018 to 2020 – has masked the fact that fossil gas prices are now structurally higher. In part, this is due to growth in the trade of liquefied natural gas (LNG). This has served as a swing supplier, exposing markets to marginal prices set not just by regional production and demand balances – as well as pipeline imports – but by other regional markets dependant on imports.

The result is little talked about, but significant when considering the economics of the energy transition. Since November 2013, the 15-year running average fossil gas price in Europe, prior to the recent spike, has averaged more than twice that of January 2005 (Figure 1.9). The recent price increases, which are expected to be maintained throughout 2022, will only serve to send that rolling average higher.

Figure 1.9 European fossil gas prices by month and 15-year rolling average, 1989-2022



Source: IMF, 2022b.

Note: The orange line represents the 15-year rolling average of monthly Title Transfer Facility (TTF) gas prices.

The increase in coal and fossil gas prices in 2021 and to-date in 2022 has highlighted that for Europe, the low-cost era of fossil gas ended in 2004

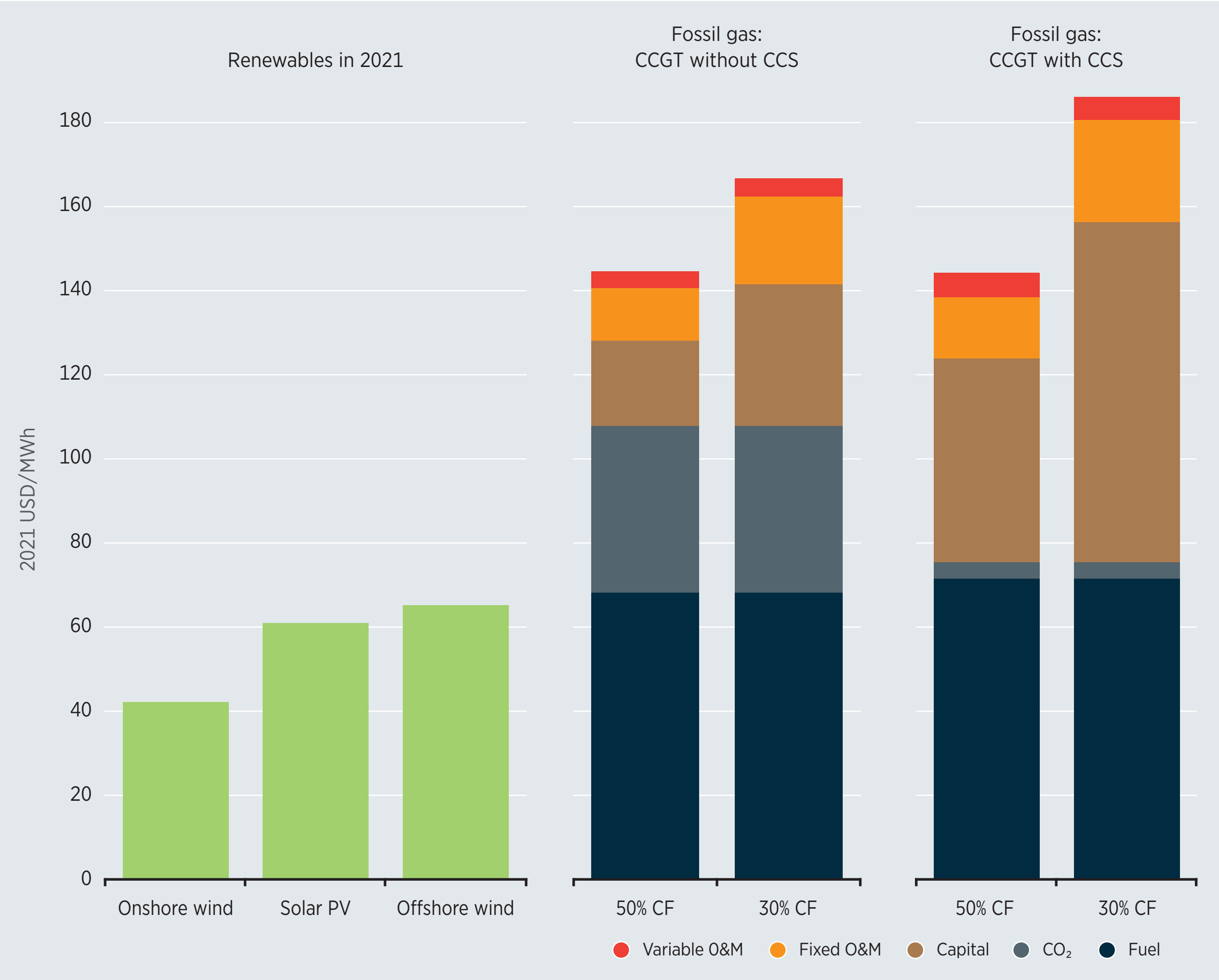
As the share of renewables grows, fossil gas-fired power plants are looking at worsening economics as capacity factors decline and even combined-cycle gas turbine (CCGT) power plants are likely to increasingly shift to shoulder and peak supply. In this context, taking the 15-year rolling average, long-run fossil gas costs for generation prior to the 2021 and 2022 price spike would stand at an implied USD 34/MWh. Given that, assuming an average efficiency of 50% over a plant's lifetime in shoulder/peaking mode and a European Union (EU) Emissions Trading Scheme (ETS) price of EUR 90/tonne (euros), a new fossil gas-fired CCGT would therefore have fuel and carbon-only costs of USD 107/MWh. This is a level 75% higher than the weighted average full lifetime cost (including capital repayment) for Europe of new solar PV commissioned in 2021, which was around USD 61/MWh. It is a full 155% higher than the cost of new onshore wind power commissioned in 2021 in Europe, which came in at USD 42/MWh.

In addition, another USD 37/MWh should be added to the CCGT costs when factoring in fixed and variable operating costs and a required real return on capital of 7%, assuming a 50% capacity factor. This brings the total cost of electricity for a new CCGT in Europe today to around USD 145/MWh (Figure 1.10), with higher costs in it's first years of operation given current fossil gas pricing. The gap between fossil gas and onshore wind is therefore at least USD 103/MWh, rising to USD 122/MWh if a capacity factor of only 30% is achieved by the CCGT given increased commitments to renewable power deployment in 2022. For solar PV, the gap then becomes from USD 84/MWh to USD 103/MWh, while for offshore wind, the gap is from USD 80/MWh to USD 99/MWh.

The situation changes somewhat if the hypothetical capital and operating costs of a fossil gas-fired CCGT for deployment in 2025 including carbon capture and storage (CCS) are included. With a EUR 90/tonne CO_2 price, a CCGT plant achieving a 50% capacity factor could potentially have costs broadly similar to an unabated one. In this case, the higher capital costs (USD 2 635/kW for a CCS equipped CCGT, compared to USD 1 100/kW for an unabated solution), along with higher fixed and variable O&M costs and efficiency penalties, are more or less exactly offset by the reduction in CO_2 emissions.[29]

[29] It is worth noting that if upstream emissions from the fossil gas system were apportioned to each sector and priced at the same price per tonne of CO_2 equivalent, the LCOE of unabated and abated fossil gas plants would rise by USD 10/MWh to USD 15/MWh over and above what has been presented here.

Figure 1.10 LCOE of new solar PV, onshore and offshore wind in Europe compared to fossil gas-fired CCGT plants, 2021/2025



Source: IRENA analysis based on IRENA Renewable Cost Database and Lyons, Durrant and Kochbar, 2021.

If countries are to meet their Paris Agreement commitments, however, there is little scope for new unabated fossil gas on any scale.

There are two critical conclusions from this for Europe:

1. On a standalone basis, new fossil gas-fired power generation in Europe does not look likely to be economic over its lifetime in the near future, although as a replacement for retiring (less efficient) gas-fired capacity, there might be a business case, depending on the market.

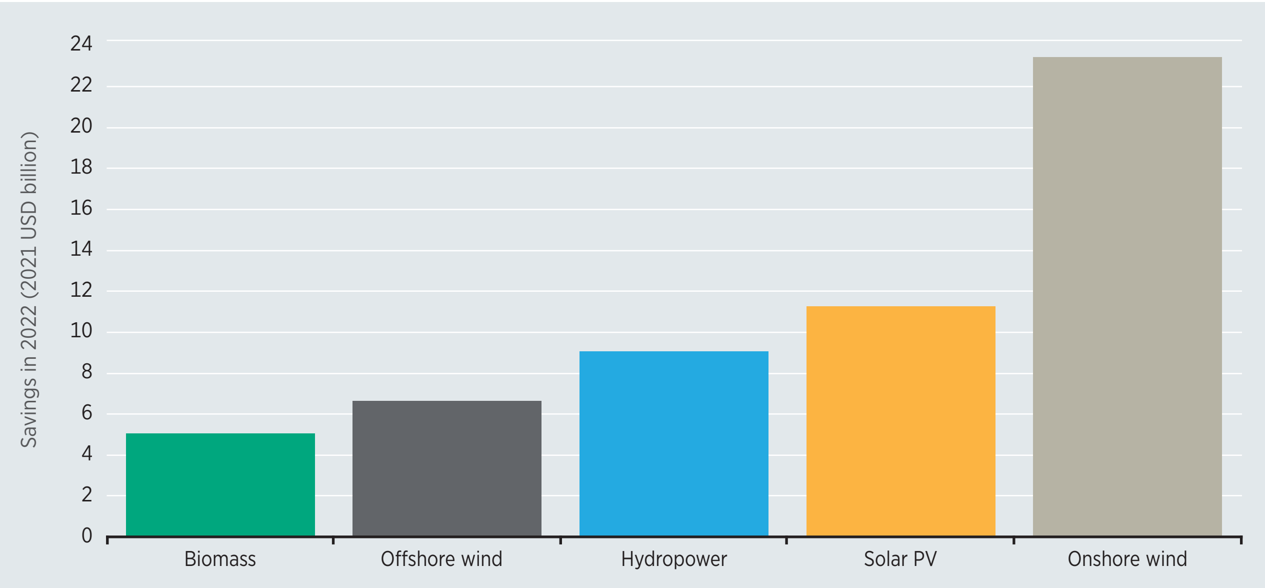
2. The window of opportunity that previously existed for fossil gas to be an economic source of firming capacity in a scenario with a high amount of variable renewable energy (VRE) appears to be closing, as the wedge between fossil gas and solar and wind costs widens. This greatly expands the range of economic clean solutions (*e.g.* pumped hydro, batteries demand-side management, sector coupling, hydrogen, etc.) for balancing an electricity grid with high shares of VRE.

NEW RENEWABLES CAPACITY ADDED IN 2021 SAVES BILLIONS OF DOLLARS IN FOSSIL FUEL ELECTRICITY COSTS IN 2022

Taking the expected capacity factors for the first year of operation and expected marginal generating costs of fossil fuels in 2022, IRENA estimates that the renewable power generation capacity added in 2021 will save at least USD 55 billion from global energy generation costs in 2022. This is after the LCOE of the new renewable capacity has been subtracted – which is to say that in 2022, there will be a net saving in electricity system generation costs (Figure 1.11).

With a low LCOE and a capacity factor that averaged 39% in 2021 for new capacity, onshore wind will be the largest contributor to these savings, at an estimated USD 23.4 billion over the year, or 42% of the total. Utility-scale solar PV projects are the next largest contributor, at USD 11.3 billion, followed by hydropower, at USD 9.1 billion, offshore wind, at USD 6.6 billion, and bioenergy, at USD 5.1 billion.

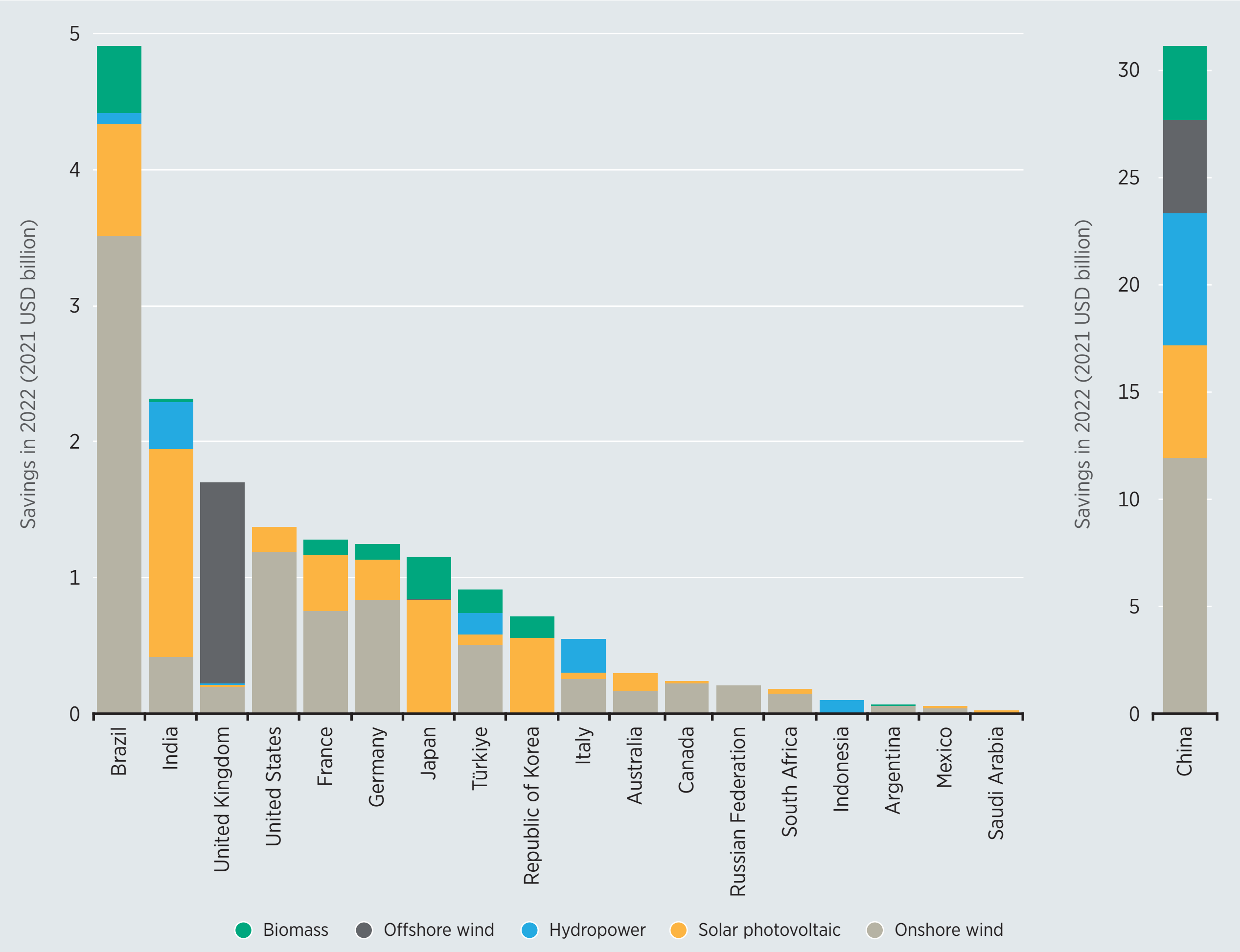
Figure 1.11 Estimated savings in 2022 after new renewable capacity added in 2021 has displaced fossil fuel generation in 2022, by generation technology



Sources: IRENA analysis based on the IRENA Renewable Cost Database and marginal generating costs from Figure 1.7 above.

As China is the largest market for new onshore and offshore wind, solar PV and hydropower, it leads the potential savings by country. This is despite it having a lower average avoided cost, due to the displacement of some cheaper-than-gas, coal-fired power generation. China might see reduced generation costs in the order of USD 31 billion (56% of the global total) in 2022 due to the new renewable capacity it added in 2021 (Figure 1.12). Brazil, with its very competitive onshore wind resource, is the next largest beneficiary, and might save in the order of USD 4.9 billion in 2022 from the renewable capacity it deployed in 2021. India is a large market for new capacity additions, but, in common with China, it also faces lower avoided costs due to the mix of coal and natural gas-fired generation being displaced. With high marginal gas priced generation in Europe expected to continue in 2022, large European markets, such as the United Kingdom, France and Germany, will all see net savings of over a billion dollars each in 2022 from projects newly commissioned in 2021.

Figure 1.12 Estimated savings in 2022 from new renewable capacity added in 2021 that displaces fossil fuel generation, by G20 country and generation technology



Source: IRENA analysis; see Annex I for more details.

The above analysis only considers new capacity added in 2021, but the savings from the stock of renewable generation capacity are even more significant. Taking, for example, Germany for the period January 2022 to May 2022, we see just how beneficial renewable power generation is in 2022. Taking the wholesale electricity price as the value of renewable generation over this period and subtracting the estimated stock generation weighted average LCOE[30] from this yields a ballpark figure for society's savings from renewable generation.[31]

[30] This is calculated using the data from the IRENA Renewable Cost Database for the period 2010 to 2021 inclusive. The figures are weighted by generation rather than capacity, to ensure the LCOE most closely reflects that appropriate for comparison with 2022's actual generation. If capacity factors by technology were broadly static through time, a capacity-weighted approach could have been used, but onshore and offshore wind capacity factors have been growing over time. Only utility-scale projects are included. Generation for solar PV is adjusted to reflect its share of solar generation by assuming utility-scale capacity factors are 10% higher on average than rooftop, thus around 40% of generation is attributed to large-scale solar PV.

[31] In Germany, the majority of these benefits fall to consumers due to the way in which Germany has promoted renewables. In many countries, however, the incidence of the benefit varies and may be captured partially or wholly by utilities, consumers (including in differing amounts to different classes of consumers), large industrial users or even neighbouring countries, if cross-border contracts are in place. Along with wholesale electricity market reform, this is likely to be a hot topic in the coming years, given increases in tariffs for consumers.

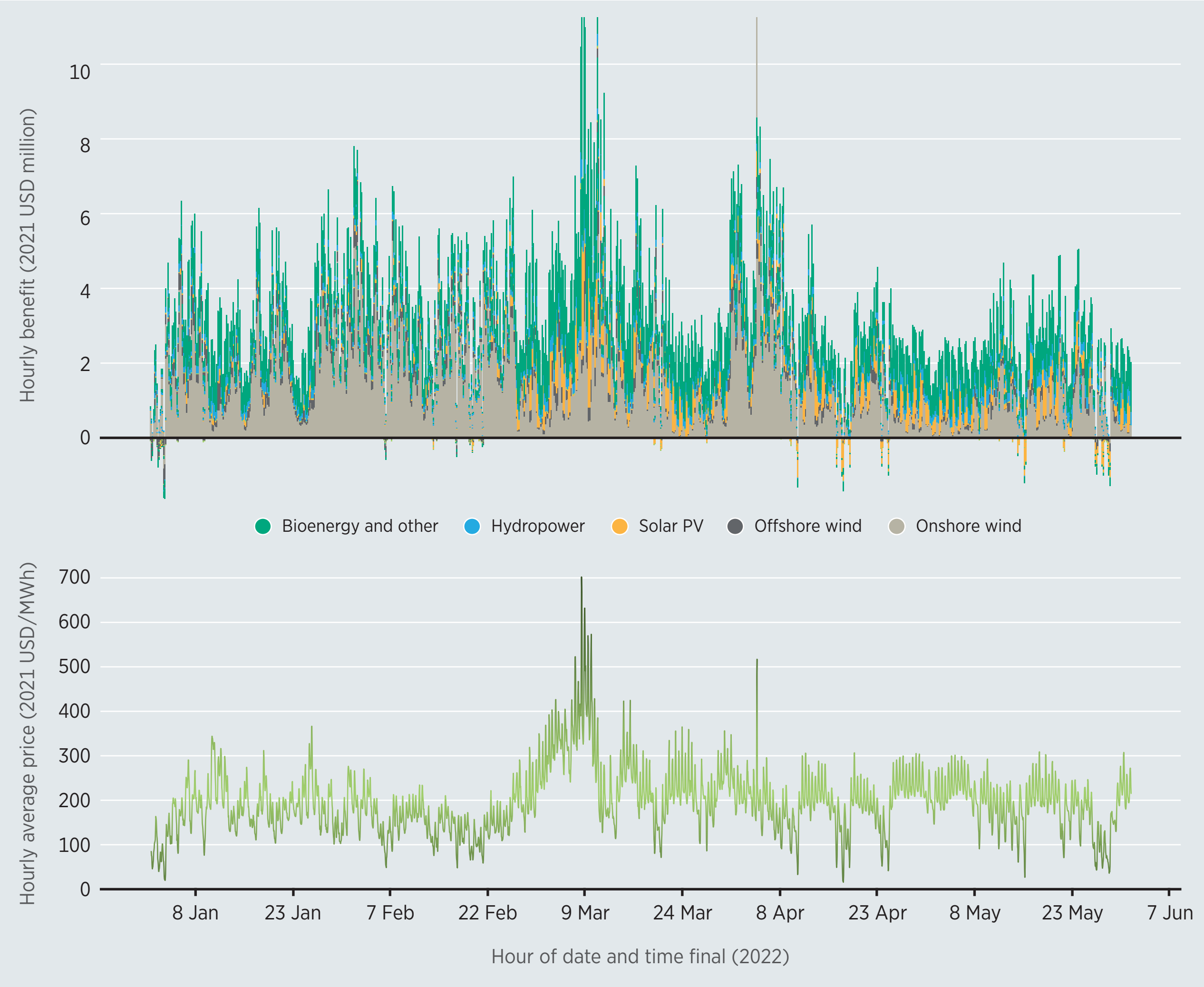
Between January 2022 and May 2022, the marginal cost saving from renewable generation averaged around USD 10.3 billion, or USD 68 million/day. On one day, 4 April 2022, renewables reduced costs by USD 170 million, with an hourly reduction of over USD 20 million at 8 a.m. that day alone.

Onshore wind, with generation of 53 terawatt hours (TWh) over the period, accounted for USD 5.9 billion (58%) of the savings. On 4 April 2022, onshore wind accounted for USD 131 million (77%) of the daily savings, as generation was very strong that day. With 11 TWh of generation over the period, offshore wind accounted for USD 850 million of the savings. Large-scale solar PV generated an estimated 9 TWh over the period, saving around USD 771 million, or 7% of the total. It is also worth noting that solar PV achieved a higher average realised price over January to May 2022 than other technologies.

Over the same period, bioenergy for power generation contributed 19% of the savings (USD 1.9 billion) on the back of 15 TWh of generation, even though bioenergy is relatively expensive. The remaining renewable sources contributed USD 796 million, notably from hydropower.[32] Figure 1.13 presents the results for the hourly savings by technology, as well as the simple average of the 15-minute wholesale electricity price, calculated on an hourly basis.

[32] *Given the age of these plants, it was assumed they were fully depreciated and only operating an incremental capital cost for refurbishment, which was factored in at an estimated USD 40/MWh.*

Figure 1.13 Germany: Estimated hourly net cost savings from renewable generation and wholesale electricity prices, January-May 2022



Source: IRENA Renewable Cost database and German Federal Network Agency (Bundesnetzagentur), 2022.
Note: The Y-axis for the hourly net benefit from renewable generation has been truncated to better show the trend for the majority of hours. The figure excludes estimated generation from small-scale solar PV.

Fossil fuel imports avoided

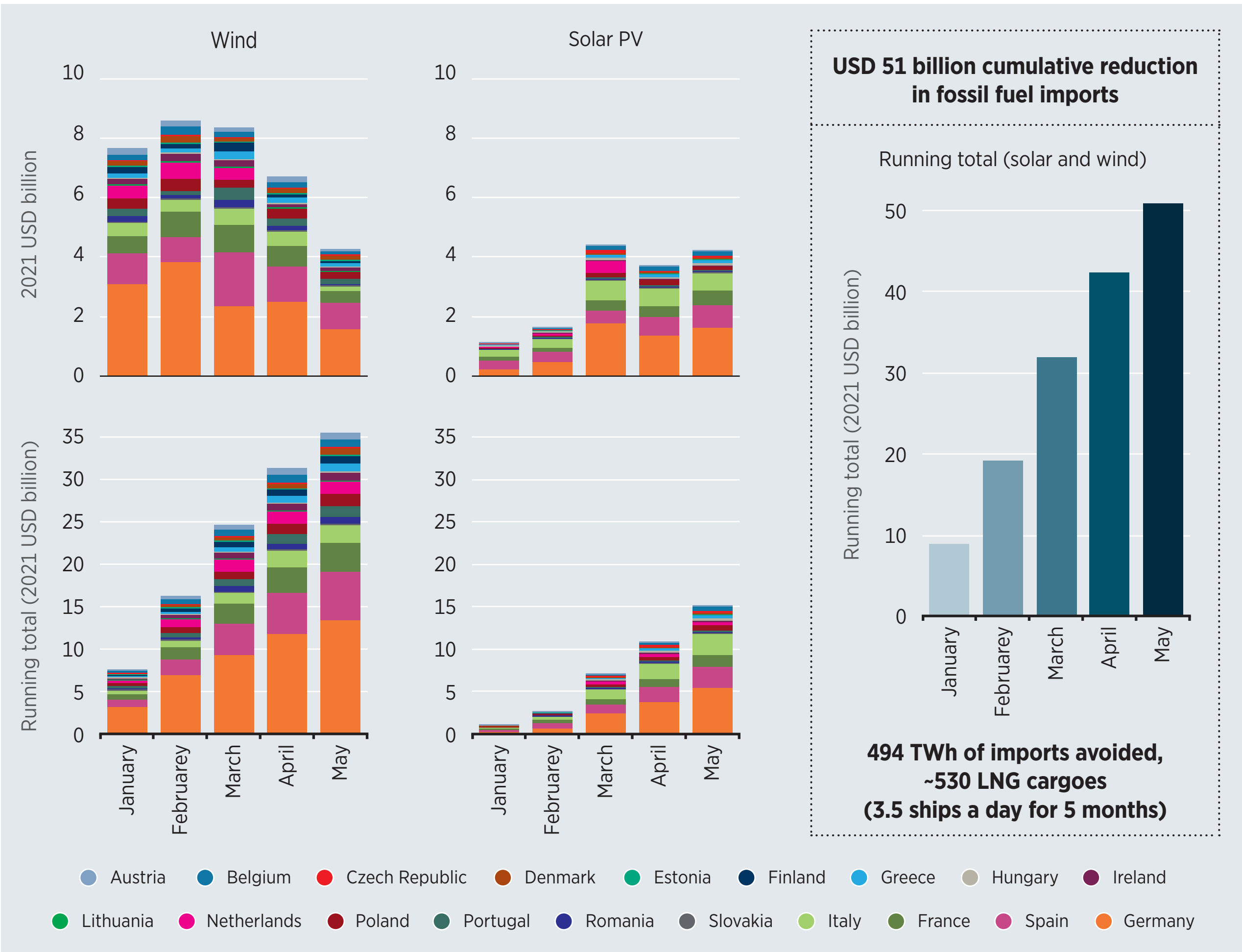
If we assume Germany had pursued a fossil gas strategy instead of a renewable energy one, replacing the electricity generated by solar and wind generation between January and May 2022 would have required around 178 TWh of additional gas imports – 36% more than actually occurred for all uses, not just for power generation.[33] Additional fossil gas imports of 36 TWh would have been needed in January 2022 – 28% more than was actually imported for all uses in that month. In February, the amount would have been 48 TWh (44% more); in March, 28 TWh (30% more); in April, 35 TWh (43% more); and in May, 32 TWh. Under this hypothetical scenario, solar PV and wind power generation from January to May 2022 avoided the need for USD 19 billion in fossil gas imports. Over the period, this would be the equivalent of around five LNG tankers docking every four days to unload cargoes, just for Germany.

[33] *The data for solar and wind generation is from the German Federal Network Agency (Bundesnetzagentur, 2022) and the gas import data from the German Statistics Office, see www.destatis.de/EN/Themes/Economy/Foreign-Trade/Tables/natural-gas-monthly.html accessed 15 June 2022.*

Applying the same approach to 19 European countries, solar PV and wind power generation in the EU for the period January 2022 to May 2022 totalled 243 TWh (Figure 1.14). This renewable energy input might have avoided the need for around 490 TWh of fuel imports[34] for fossil fuel-fired generation given the relative inefficiency of fossil fuel-fired generation options, reducing fossil fuel import bills by a total of USD 51 billion for the period, or by USD 336 million/day, on average. If this had all come from gas-fired generation, it would have necessitated the equivalent of around 530 LNG cargoes.

As the EU's largest economies, France, Germany, Italy and Spain have been the main beneficiaries of renewables' displacement of fossil-gas generation. Strong wind generation, in January 2022 and February 2022 in particular, saw total wind generation of 174 TWh over the period, accounting for USD 35.6 billion, or 70% of the total savings. Solar PV generation grew steadily each month as winter receded, with a cumulative total of 69 TWh for the period –potentially avoiding USD 15.2 billion of fossil fuel imports.

Figure 1.14 Estimated fossil fuel imports avoided due to solar and wind generation, 19 European countries, January-May 2022



Source: IRENA analysis based on Ember, 2022; German Federal Statistical Office (Statistisches Bundesamt), 2022b; and IMF, 2022b.

[34] *This is a theoretical maximum, and an alternative hypothetical where lignite generators in Europe expanded operations would reduce the import savings. But it is difficult to see how this would have been possible given Europe's commitment to addressing climate change mitigation goals and in recent years, the Paris Agreement goals.*

Conclusions

The preceding analysis has made clear that during the current fossil fuel crisis:

- New renewable capacity added in 2021 is, under a plausible set of assumptions for fossil fuel costs for the rest of the year, likely to significantly reduce electricity system generation costs in 2022, with potential savings of at least USD 55 billion globally this year.

- In Europe and elsewhere, the very high marginal generation costs from coal and fossil gas means that the stock of existing renewable capacity – including solar and wind procured early last decade at higher costs than currently – is contributing to a reduction in electricity generation costs by even greater values.

- The electricity generated by renewables is offsetting fossil fuel generation and hence, for importing countries, dramatically reducing the need for fossil fuel imports. This is particularly striking if compared to a scenario in which renewables deployment had not been accelerated by government policy over the last decade.

- The impact of the fossil fuel price crisis would be much more severe without the contribution of renewables in insulating electricity systems from the full weight of the fossil fuel price crisis.

- Given macroeconomic spill-over from the inflation of fossil energy prices, renewable energy's benefits (in terms of energy security, reduced imports, insulation from fossil fuel price volatility, etc.) have, however, not been adequately valued/remunerated. It is worth considering this in policy settings in the years to come.

Overall, given the large scale of the likely savings from renewables for the year 2022 and potentially beyond, it remains remarkable that more effort has not been made to accelerate renewable power generation deployment in 2022 over the past nine months.[35] This is before even considering the social and environmental benefits renewables also represent.

INFLATION, COMMODITY PRICE INCREASES AND THE IMPACT AND OUTLOOK FOR RENEWABLE POWER GENERATION EQUIPMENT COSTS IN 2021 AND 2022

In 2021 and 2022, a complex set of interconnected issues has seen inflation pressures surge in both emerging and advanced economies. The combination of lingering supply chain disruption from the COVID-19 pandemic (from factories to ports) and surging demand, as vaccination rates allowed a semblance of normality, has created unprecedented challenges. Commodity, energy and food prices rose, only to be pushed even higher by the crisis in Ukraine. At the same time, the labour market has been tight in many countries, resulting in skills shortages and hampering a return to a more balanced economic setting.

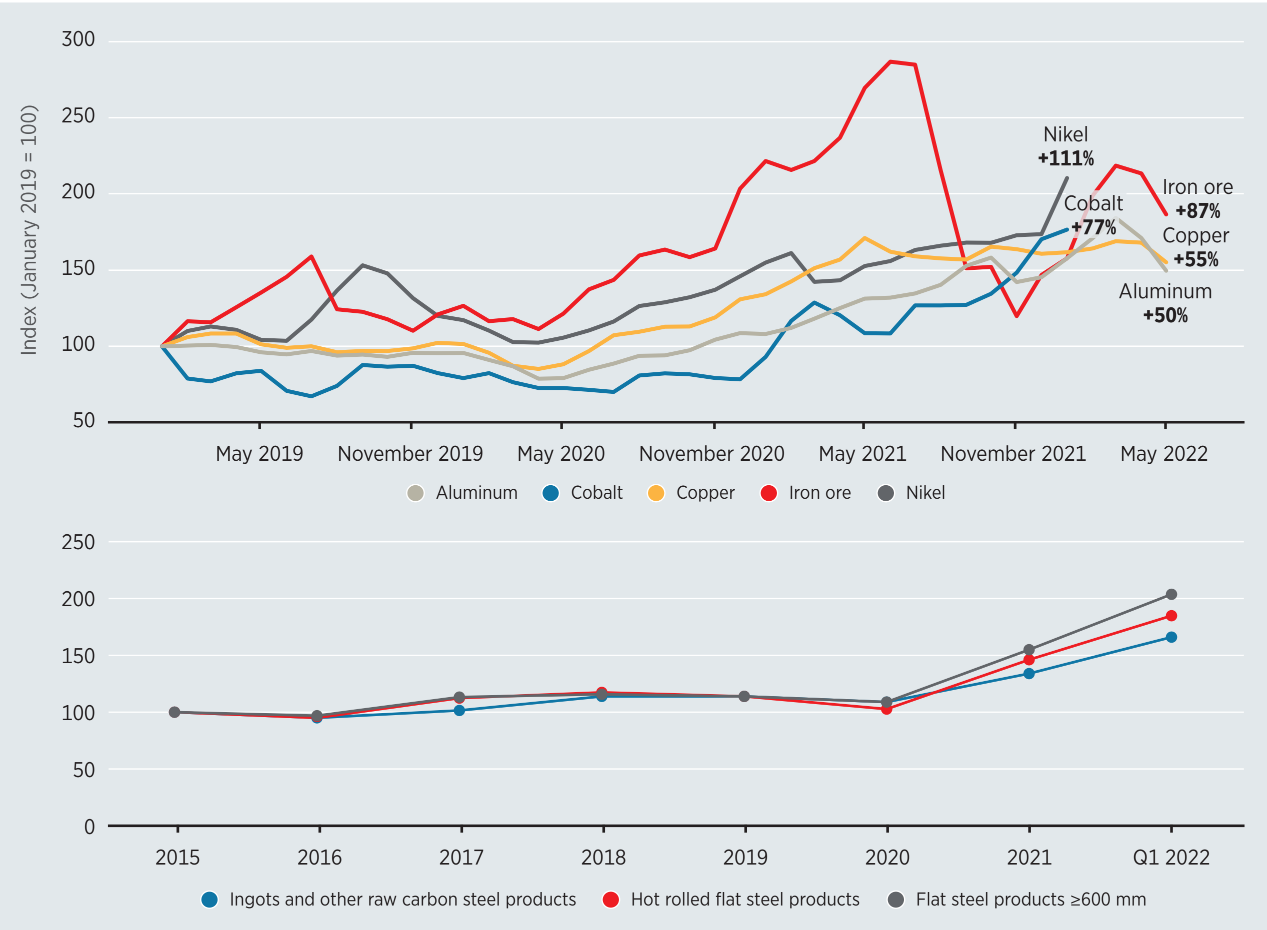
The energy sector is also an important consumer of materials. Increasing prices for steel, aluminium, cement, polysilicon and other inputs will inevitably have an impact on the cost of developing energy projects, whether they are wind turbines or transmission lines, oil and gas projects or their pipelines.

[35] *The same could also be said for the rapid scale-up of existing energy efficiency programmes, which would provide similar benefits.*

Between January 2019 and May 2022, international commodity prices increased significantly (Figure 1.15). Aluminium can account for as much as 10% of solar PV module costs (Tummalieh *et al.*, 2021) and is also used in wind turbines. Between January 2019 and May 2022, the price of aluminium increased by 50%, but was as much as 84% higher in March 2022. Copper, which is used extensively in all electric power generation technology, but notably in generators and cabling prices, saw its price increase by 55% between January 2019 and May 2022. That figure is also at the lower end of the range it has traded within since April 2021.

Steel is an important component of wind turbine towers and foundations and iron ore is one of the two essential raw materials for most iron and steel production (along with coking coal). By June 2021, iron ore prices had surged 187% since January 2019, but have since dropped back, and were 87% higher in May 2022 than it was in January 2019. Figure 1.15 illustrates steel product prices on an annual basis, allowing us to see through the volatility in monthly data, with the data for Germany showing the surge in prices in 2021 and through Q1 2022.

Figure 1.15 Key international commodity price trends (monthly) and German steel product producer price index (annual), 2015-Q1 2022



Source: IMF, 2022a and German Federal Statistical Office (Statistisches Bundesamt), 2022a.

As noted above, however, these increases in material commodity prices have been dwarfed by the surge in fossil fuel prices. In addition to growing demand, surging fossil fuel prices also explain some of the increase in costs for energy intensive materials such as steel products, cement and aluminium. Tight supply and demand balances, supply chain disruptions and transport issues have also been factors driving prices higher.

Commodity price increases: Impact on solar and wind costs for 2022

The extent to which increases in materials and transportation costs, as well as other supply chain cost increases, get passed on into higher costs for components in solar and wind projects depends on a variety of factors. These include: the intensity of use of the materials; the ability to substitute cheaper alternatives; the impact of additional efficiency improvements; and market power (*e.g.* to what extent costs cannot be passed on and will be absorbed in lower or negative margins). In other words, a 10% increase in the cost of a component that normally accounts for 10% of the project cost does not necessarily result in a 1% increase in total cost.

Solar PV

For solar PV projects, the main cost categories that are heavily affected by materials prices are:

- modules and inverters;
- racking and mounting systems, including the foundations, which can be all steel, or a combination of steel and concrete;
- grid connection: where copper is used in transformers and/or in lines; and
- cabling and wiring within the PV plant, where copper is again a major cost component.

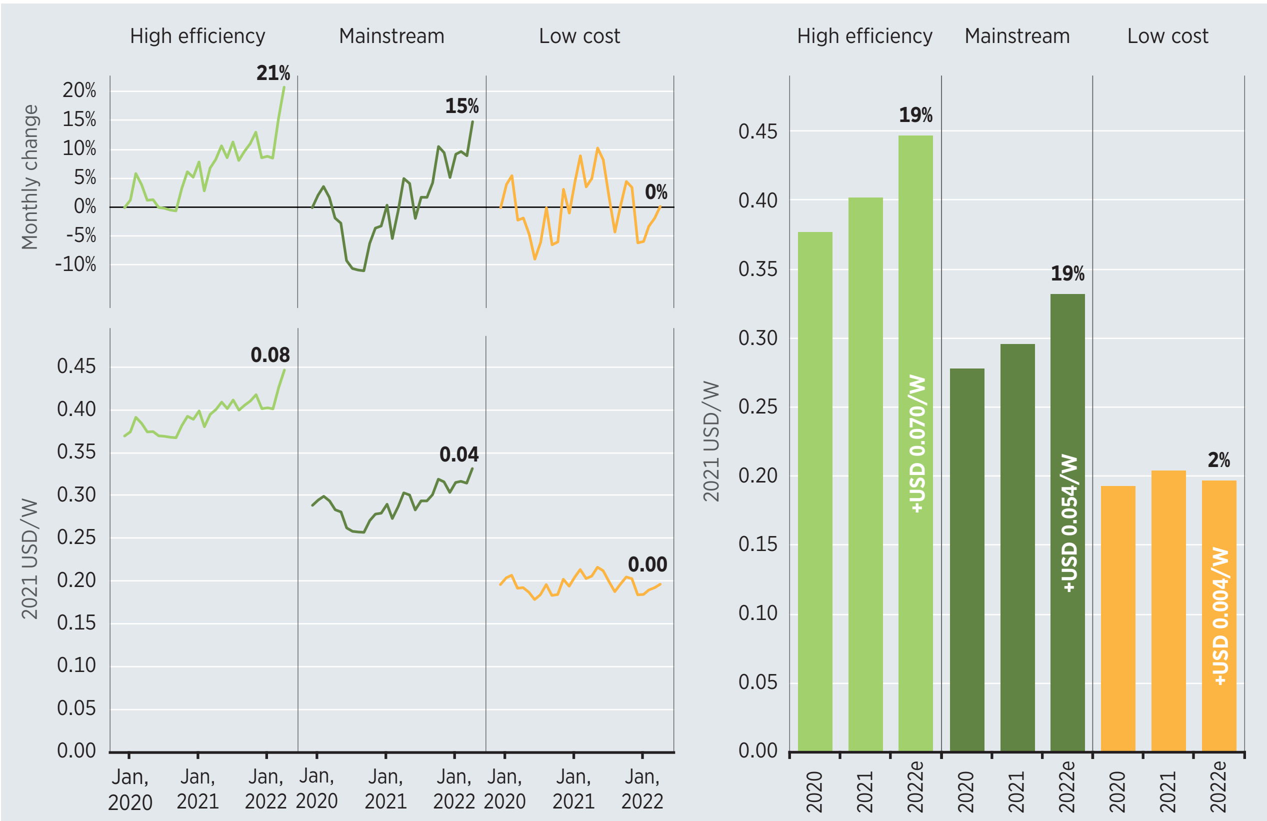
In the top ten utility-scale solar PV markets for 2021 by capacity, modules and inverters, combined, accounted for between 24% and 54% of the total installed costs of the utility-scale solar PV projects commissioned. The other three cost categories mentioned above accounted for between 15% and 30% of total installed costs in these markets.

The impact on solar PV module pricing in Europe of the COVID-19 pandemic in 2020, supply chain tightness in 2021 and commodity price increases in 2021 and 2022 can be seen in Figure 1.16. Prices were weak or fell in 2020, as economic sentiment and PV installations fell during lockdowns in Q2 2020 and Q3 2020, before rising at the end of Q4 2020. A correction again occurred in Q1 2021, as Europe endured another COVID-19 wave, before prices rose on the back of the factors already discussed. There was a correction to prices in Q1 2022 for 'high efficiency' product groupings, while 'mainstream' product prices held steady (see Chapter 3 for more details). Prices rose again in April and May for most product categories, however. In May 2022, prices for 'high efficiency' modules were USD 0.08/W higher than in January 2020, while they were USD 0.04/W higher for 'mainstream' products. The 'low cost' segment remained unchanged.

In the top ten utility-scale solar PV markets by capacity in 2021, modules and inverters accounted for 24-54% of total installed costs of commissioned projects

Looking at one scenario for 2022, in which prices for the whole year average at the highest monthly value seen for the year so far,[36] prices would be 21% higher in 2022 than in January 2020 for 'high efficiency' modules. For 'mainstream' modules, they would be 15% higher and for 'all black' modules, 13% higher, while 'low cost' module prices would be unchanged and bifacial module prices would be 1% lower.[37] Comparing this scenario for average 2022 prices with average prices in 2020, 'high efficiency' and 'mainstream' module prices in 2022 would be USD 0.07/W to USD 0.05/W higher – a 19% increase (Figure 1.16). Compared to 2021 prices, they would be 11% to 12% higher. Bifacial module prices in 2022 would then average 8% more than in 2020, or 4% more than in 2021, while 'low cost' modules would be 2% higher in 2022 than in 2020, but 3% lower than in 2021.

Figure 1.16 Solar PV module prices in Europe by module type, 2020-2022



Source: pvXchange, 2022.

Note: Monthly data is presented on the left-hand side and annual data on the right-hand side. The average module price for 2022 is an estimate based on actual data for January to May 2022, with prices for the rest of the year set at the highest monthly average value to date.

[36] *Which would be USD 0.45/watt (W) for 'high efficiency' and bifacial modules, USD 0.43/W for 'all black' modules, USD 0.33/W for 'mainstream' modules and USD 0.20/W for 'low cost' modules.*

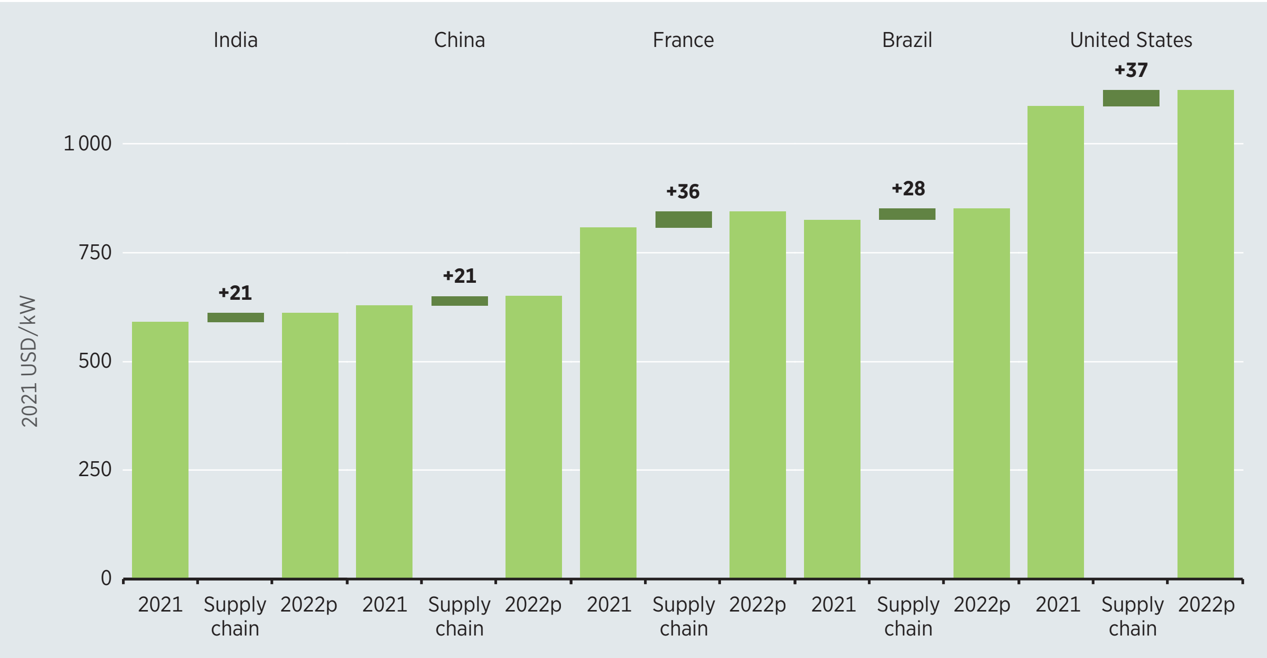
[37] *Exchange rate fluctuations could make these percentage changes greater or lower.*

One of the major drivers of solar PV module cost increases in 2021 and 2022 were rising polysilicon prices. Polysilicon prices increased from USD 9/kilogramme (kg) in Q1 2020 to an average of around USD 33/kg between January and May 2022 (Bernreuter, 2022; PV Infolink, 2021 and Energy Trend, 2021). This increase in price more than offset improvements in materials intensity as a result of module efficiency and manufacturing improvements. As a result, the indicative overall cost per watt of polysilicon for solar PV cells rose from USD 0.025/W in 2019 to USD 0.068/W in Q1 2022. This is an increase of USD 0.043/W over the period. Yet, because of improvements in material intensity and the efficiency of solar cells, this is less than IRENA's estimate of the underlying increase for polysilicon over the period 2019 to 2022, which was USD 0.048/W (see Annex I a detailed explanation of this dynamic).

Aside from polysilicon, which is a key cost driver, aluminium and solar glass are the largest materials by weight in a PV module (Frischknecht *et al.,* 2020). The latter has not been a major driver of cost change over the last two years, with solar glass prices of USD 4/kg in 2020 rising to USD 4.45/kg in 2021, before dropping back to an average USD 4.1/kg between January and May 2022 (Business AnalytIQ, 2022). Aluminium, which accounts for around 15% of the weight of a PV module, is used in their frames to provide rigidity and strength, protecting the modules from damage. Aluminium alloy prices rose sharply up to a March 2022 peak of around USD 2 800/kg (Figure 1.15). They then fell sharply to under USD 1 800/kg by May 2022. This was still higher than the 2020 average of around USD 1 300/kg, but suggests module price pressures from aluminium costs are easing.

The largest materials cost in the racking and mounting category is steel – although where pile or screw steel foundation options can't be used, concrete is also an important cost component. For the internal electrical cabling and grid connection, copper is the main materials cost driver. With increases in the price of these materials, costs for projects are likely to rise in major markets in 2022.

Figure 1.17 Possible utility-scale solar PV total installed cost trends in 2022



Source: IRENA analysis.

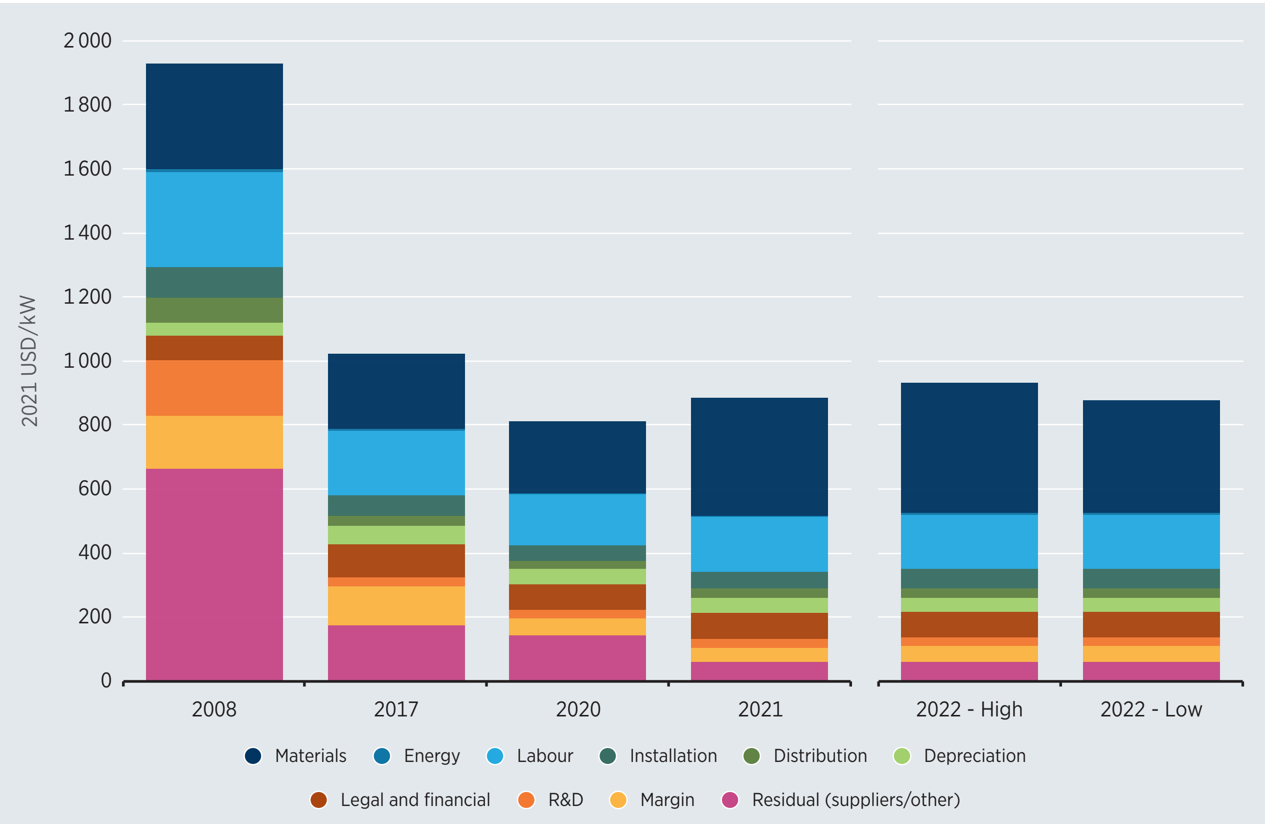
Note: The values for 2022 are possible outcomes based on assumptions for full-year materials prices and for the remaining pass through of costs; they are not forecasts.

Overall, although significant uncertainty exists, it is possible that in 2022, the pass through of recent material price increases could result in total installed costs increasing by between USD 20/kW and USD 60/kW on top of 2021 levels in the ten solar PV markets that were the largest in 2021. This would represent an increase of 3% to 5%, depending on the market, and increase the LCOE by around 2%. Figure 1.17 provides an overview of the potential change in the total installed costs between 2021 and 2022 for Brazil, China, India, France and the United States. With volatile materials prices and an uncertain future, however, higher or lower outcomes for 2022 are possible.

Onshore wind

IRENA and the University of Cork examined the cost components for onshore wind turbines between 2008 and 2017 to understand the underlying drivers of cost reductions in wind turbines (Elia, *et al.,* 2020), including an assessment of the materials cost and intensity and how these had changed over time. This analysis is representative of markets outside China and India, as these two countries have very different cost structures and would require a separate analysis. In the case of China, for example, wind turbine prices actually fell in 2021, as developers pressed manufacturers to lower prices in the face of the end of subsidy support.

Figure 1.18 Representative wind turbine price evolution by cost component, 2008, 2017, 2020, 2021 and 2022



Source: IRENA analysis based on Elia, A. et al., 2020.

Note: Cost components are normalised to the average representative wind turbine cost by year for the period 2008 to 2021. The 2022 values are estimates based on assuming constant 2021 values for all cost components, except for materials, installation and margins and do not represent a forecast of 2022 wind turbine prices; see Annex I for more details about the input assumptions.

The year 2021 was marked by the impact of supply chain disruptions and increases in transportation and materials costs. Updating our analysis shows that estimated higher materials prices contributed to a USD 145/kW increase in materials costs for the wind turbine. This was 65% up on the materials costs in 2020, which was a year marked by low commodity prices. Representative wind turbine prices, however, rose by just USD 73/kW between 2020 and 2021. Wind turbine manufacturers' margins were therefore squeezed in 2021, as their ability to pass through cost increases was limited.

International Monetary Fund (IMF) expectations are that commodity prices will remain elevated in 2022 (IMF, 2022a) and although there is significant uncertainty, this analysis has therefore assumed prices will remain elevated for the rest of the year, at or near their recent maximums (see Annex I for a more detailed analysis of the materials costs for wind turbines and the assumptions). Distribution and installation costs (predominantly due to continued pass through of higher transportation costs) are also assumed to increase.

Taking all of this into account, and assuming OEM will only be able to gradually raise margins, there may be little increase to still be passed through, with the level up to a maximum of USD 40/kW, if manufacturers are unable to raise their gross margins back to 2020 levels. This is unlikely to be sustainable for most wind turbine manufacturers. Taking this into account, IRENA's analysis suggests for wind turbine prices to fully capture materials price increases over 2021 and into early 2022, prices might have to increase by between USD 130/kW and USD 185/kW in 2022, relative to 2020, with a central value of USD 145/kW as noted above. This would cover materials, transportation and energy cost increases and restore margins to near 2020 levels. Given wind turbine prices in 2021 were on average USD 73/kW higher than in 2020, only around half of the USD 145/kW increase in materials prices between 2020 and 2021 therefore appears to have been passed through already. In different markets, this suggests an additional increase in 2022 by around USD 60/kW and USD 110/kW would be required. Returning OEM margins to more sustainable levels, such as those in 2017, might add another USD 50/kW to USD 60/kW to the required increase.

Assuming margins at 2020 levels, this increase in costs would represent a rise of between 4% and 8% in the weighted average total installed cost of onshore wind, excluding China and India, over 2021 values. Rising to 7% to 12% if profit margins were restored to 2017 levels.

The overall impact on total project costs is, however, uncertain. Much would depend on the extent to which 2021's wind turbine price increases were captured in the projects commissioned that year, with a larger increase possible in some markets.[38] The overall impact on the LCOE of onshore wind – excluding China and India – would however be modest – in the order of an increase of USD 0.0014/kWh to USD 0.0028/kWh, rising to between USD 0.0028/kWh to USD 0.0042/kWh if manufacturers profit margins were returned to 2017 level, given weighted average capacity factors for the rest of the world excluding China and India of 42% in 2021.

Of course, individual markets would have different outcomes, with the most competitive markets likely to see the largest percentage increases in costs, given their lower overall total installed cost structure. Another factor that needs to be considered is how much financing costs may rise in this period of higher inflation. IRENA's analysis in next year's report will include this impact now that the LCOE calculations rely on the benchmark WACC model.

[38] *BNEF data suggests that prices of delivered turbines increased by between USD 30/kW and USD 90/kW between 2020 and 2021, with an average estimate of USD 60/kW. The USD 73/kW IRENA estimate of the representative wind turbine price increase for this period is within this range, but somewhat higher than their average estimate.*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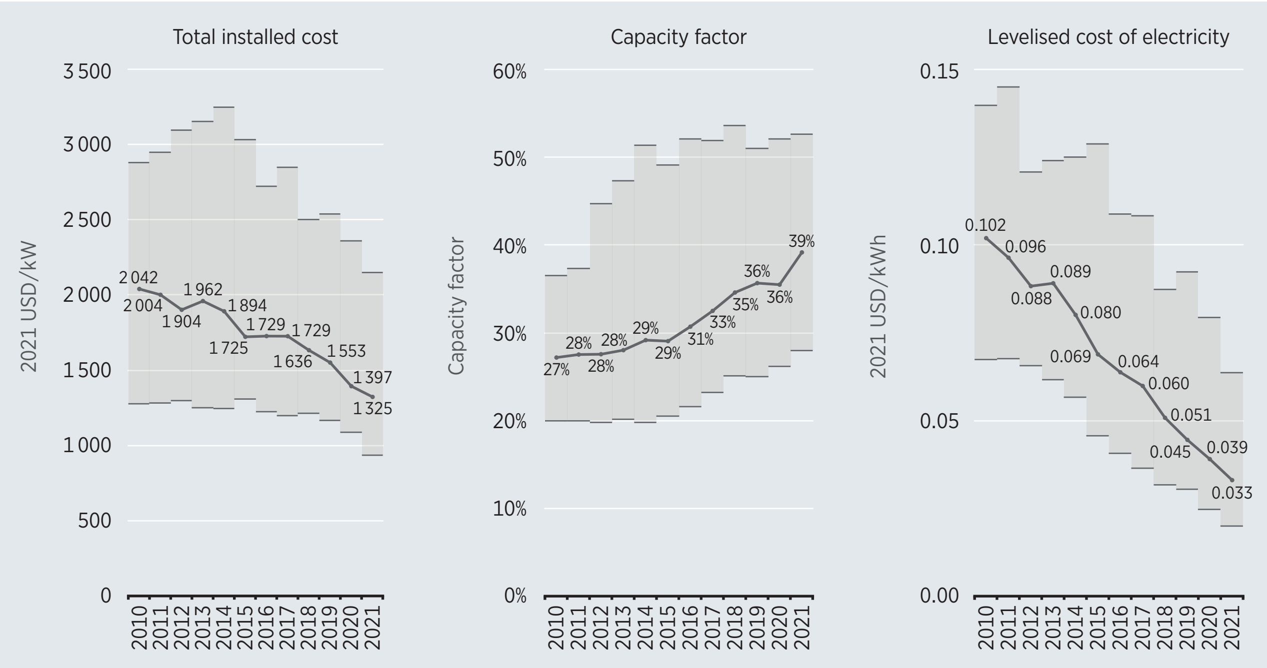
02 ONSHORE WIND

HIGHLIGHTS

- Between 2010 and 2021, onshore wind's global weighted average levelised cost of electricity (LCOE) fell 68%, from USD 0.102/kilowatt hour (kWh) to USD 0.033/kWh. In 2021, the LCOE fell 15%, year-on-year.
- In 2021, around 69 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 global cumulative capacity of onshore wind increased more than fourfold during the 2010 to 2021 period, from 178 GW to 769 GW.
- The global weighted average total installed cost of onshore wind fell 35% between 2010 and 2021, from USD 2 042/kilowatt (kW) to USD 1 325/kW. In 2021, it was down 5% on its 2020 value of USD 1 397/kW, albeit with some markets experiencing increased costs. Wind turbine prices, outside of China, increased in 2021 and into 2022, suggesting total project costs may increase in 2022.
- In 2021, the country/region weighted average total installed cost for onshore wind ranged from around USD 926/kW to USD 1 892/kW. China and India have weighted average total installed costs between 20% and 67% lower than other regions.
- In 2021, average onshore wind turbine prices ranged between USD 780/kW and USD 960/kW.Excluding China, by 2021, prices in most regions had fallen by between 48% and 62% from their peaks in 2009. In China itself, by 2021, wind turbine prices had fallen 84% since their 1998 peak of USD 2 585/kW, to average just USD 425/kW.
- Technology improvements have resulted in an almost one-third improvement in the global weighted average capacity factor of onshore wind, from 27% in 2010 to 39% in 2021.

Figure 2.1 Global weighted average total installed costs, capacity factors and LCOE for onshore wind, 2010-2021



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 the growing maturity of the sector. In 2021, the extent of onshore wind deployment was second only to that of solar photovoltaic (PV), while China was still the largest market, albeit with a lower share than in 2020.

The largest share of the total installed cost of an onshore wind project is related to the wind turbines, which today make up between 64% and 84% of the total cost (IRENA, 2018). Virtually all onshore wind turbines today are horizontal axis, predominantly using three blades and with the blades upwind.[39] Contracts for these projects typically include the towers, installation and, except in China, delivery. 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,[40] 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.

This use by the OEMs of a series of 'platforms' that offer different configurations suited to individual sites has also been an important driver of cost reductions. The platforms do this by amortising product development costs over a larger number of turbines, while also optimising turbine selection for a particular site, further reducing the LCOE.

Turbines with larger rotor diameters increase energy capture[41] 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. For example, a taller hub height means an increased distance between the blade tips and the ground, enabling installation in certain forested areas. These developments 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).[42]

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[39] *Meaning that the rotor blades are facing the wind.*

[40] *Such as different wind speeds, areas for adequate spacing to reduce wake turbulence, and turbulence inducing terrain features.*

[41] *Energy output increases, as a function of the swept area of the blades as a squared function of the surface area, which is a key variable in the power output of a wind turbine.*

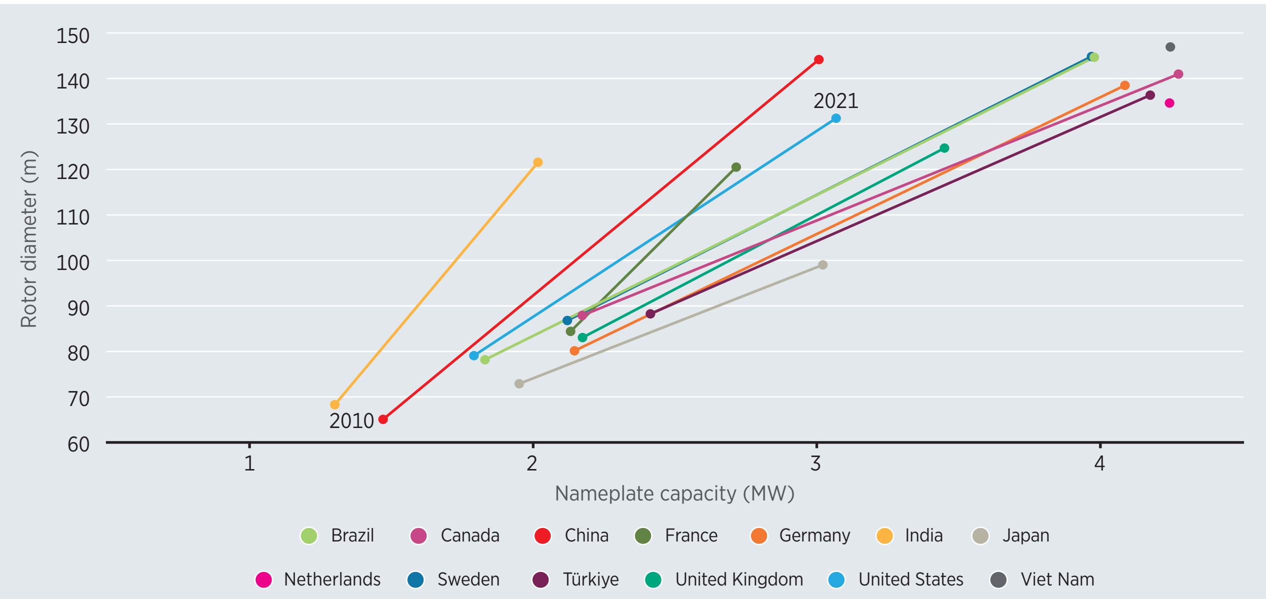
[42] *Increasing turbine size does not lead to a proportional increase in the cost of other turbine components, e.g. towers, bearings nacelle, etc. Thus, the increase in cost on a per unit basis is not as significant as might be expected.*

Figure 2.2 illustrates the evolution in average turbine rating and rotor diameter between 2010 and 2021 in some major onshore wind markets. Brazil, Canada, China and Germany stand out, with increases of greater than 70% in both the average rotor diameter and turbine capacity of their commissioned projects, over the period. In percentage terms, the largest increase in turbine capacity was observed in Brazil (121%) followed by Sweden (116%) and Canada (108%). The largest increase in rotor diameter occurred in Canada (116%) followed by China (91%) and Brazil (80%). Of the countries covered in Figure 2.2, in 2021, Canada had the largest turbine rating and Viet Nam had the largest turbine rotor diameters, on average. That year, India had the lowest turbine rating while Japan had the lowest rotor diameter. Overall, in 2021, the country-level average turbine capacity ranged from 2.0 MW to 4.3 MW, and rotor diameter from 99 metres (m) to 147 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 to the market. Due to increased government renewable energy policy support for wind deployment, however, this period also coincided with a significant mismatch between high demand and tight supply, which enabled significantly higher margins for OEMs during this period.

Yet, 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 that peak between 2007 and 2010, with annual average prices falling by between 48% and 62% between 2009 and 2021. In 2021, quarterly prices were in the range of USD 780/kW to USD 960/kW in most major markets after rising from lows in 2020, excluding China (Figure 2.3), where there was a dramatic price fall after 1998, when the wind turbine price was around USD 2 585/kW. Prices in China then declined in an irregular, step-wise fashion China's turbine markets have been out-of-step with the rest of the world. The 2020 price was around an average of USD 550/kW – somewhat above the 2019 level due to tight supply and a surge in deployment demand.[43]

Figure 2.2 Weighted average onshore wind rotor diameter and nameplate capacity evolution, 2010-2021



Source: IRENA Renewable Cost Database.
Note: Data for the Netherlands and Viet Nam are only available for 2021.

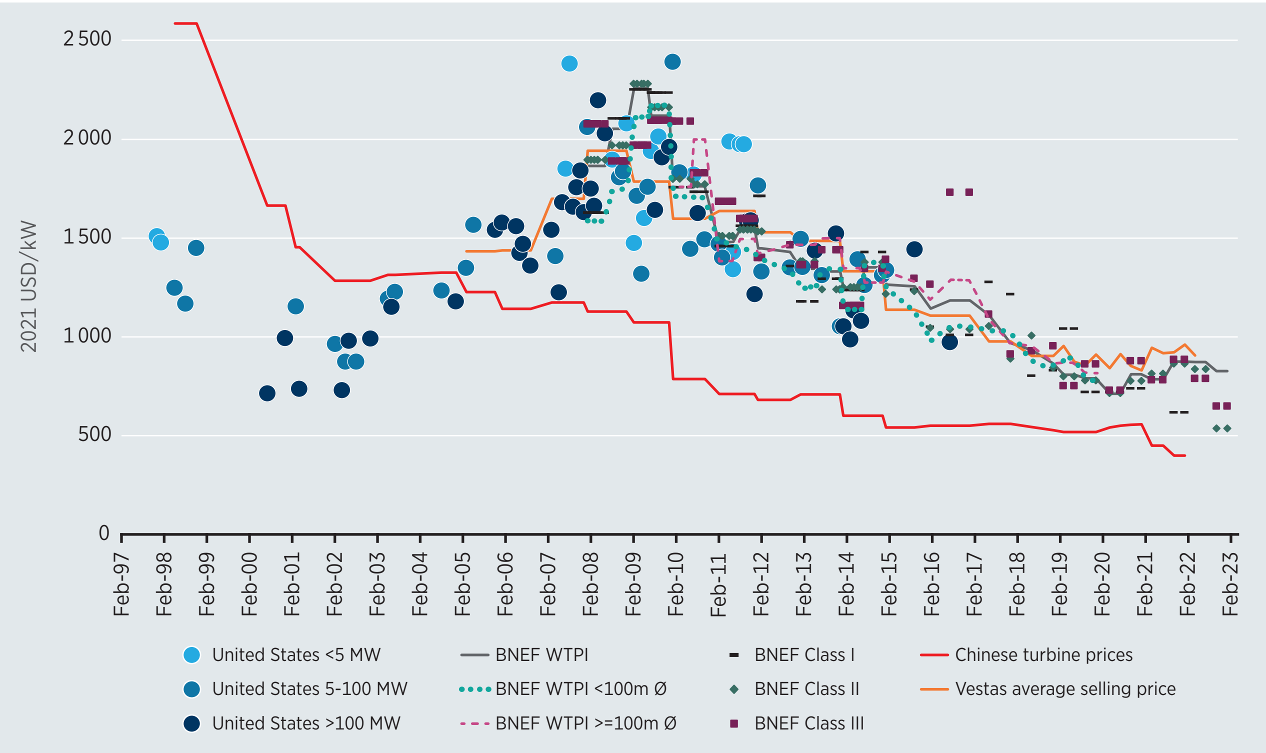
[43] *This increase in wind turbine prices in China is likely to be brief, as the policy shift to subsidy-free onshore wind has seen pressure on wind turbine manufacturers to agree to lower pricing for 2021 (Wood MacKenzie, 2021).*

In 2021, contrary to the experience elsewhere, average Chinese wind turbine prices fell to around USD 425/kW, as manufacturer's spare capacity and the end of some support schemes meant project developers were able to negotiate lower prices.

With greater competition among manufacturers, margins have come under increasing pressure, manufacturers, turbine sales margins have fallen over time and with increased commodity costs in 2021 and 2022, and probably need to rise to return to sustainable levels (Blackburne, 2022). Increased competition is being reinforced by the increased use of competitive procurement processes for renewable energy in 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, 2020). This increased competition does not make the sector immune from the impact of supply and demand imbalances, however. Significant growth in the market in 2020 and supply chain constraints due to COVID-19 saw wind turbine pricing in late 2020 and early 2021 tick up, with quarterly turbine pricing in the range of USD 780/kW to USD 960/kW for orders (excluding China) received in 2021 (BNEF, 2020b; Vestas, 2021) and have increased further in early 2022.

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 negligible difference between the prices of turbines with a rotor diameter above 100 m and those with a rotor diameter of less than 100 m. In late 2020, however, the gap between Class I and Class III[44] wind turbines started to widen (BNEF, 2020b).

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



Source: BNEF 2022; Wiser, et al., 2020; Vestas Wind Systems, 2005-2022; and the IRENA Renewable Cost Database.

[44] *This refers to the International Electrical Commission's 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.*

TOTAL INSTALLED COSTS

Between 1984 and 2021, the global weighted average total installed cost of onshore wind projects fell by 74%, from USD 5 136/kW to USD 1 325/kW, according to data from the IRENA Renewable Cost Database (Figure 2.4). Over this period, global average total installed costs fell by up to 9% for every doubling in cumulative onshore wind capacity deployed globally. This decline was driven by wind turbine price and balance-of-plant cost reductions.

Between 2010 and 2021, the global weighted average total installed cost of onshore wind fell by 35%, from USD 2 042/kW to USD 1 325/kW, with a 5% decline, year-on-year, in 2021.

Figure 2.5 shows the trend in country-specific weighted average total installed costs for 15 countries that are major wind markets and have significant time series data.

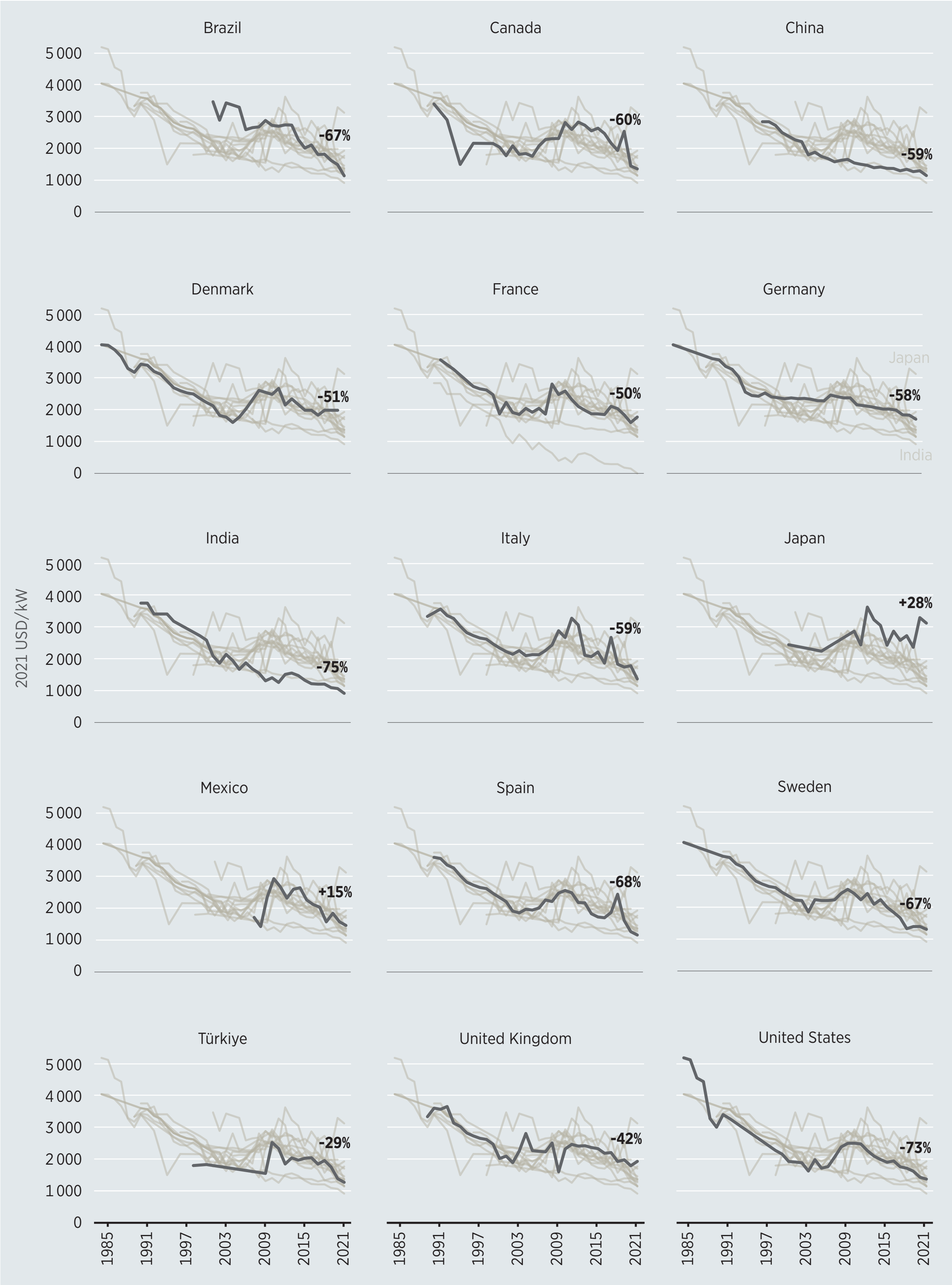
Individual countries saw a range of cost reductions – from 75% in India to just 15% in Mexico – but these comparisons need to be treated with caution, given the differing start dates for the first available data. Japan, for example, saw a 28% increase over the period shown, with the first cost data point in 2000. The more competitive, established markets show larger reductions in total installed costs over longer time periods than newer markets. India, followed by the United States, had the highest decrease in total installed costs, with reductions of 75% and 73% over their respective time frames. Spain saw a reduction of 68% and Brazil and Sweden both saw a reduction of 67%, respectively, while Canada saw a reduction of 60% and China and Italy both saw a reduction of 59%, respectively. Germany saw a reduction of 58%.

In addition, there is 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 and other factors.

Figure 2.4 Total costs of onshore wind projects and global weighted average, 1984-2021

Source: IRENA Renewable Cost Database.

Figure 2.5 Onshore wind weighted average total installed costs in 15 countries, 1984-2021



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 2021 were (in descending order): Africa, South America (excluding Brazil), Europe, Central America and the Caribbean and 'Other Asia' (excluding China and India). The regions with the next highest weighted average total installed costs in 2021 were North America, Eurasia and Oceania.

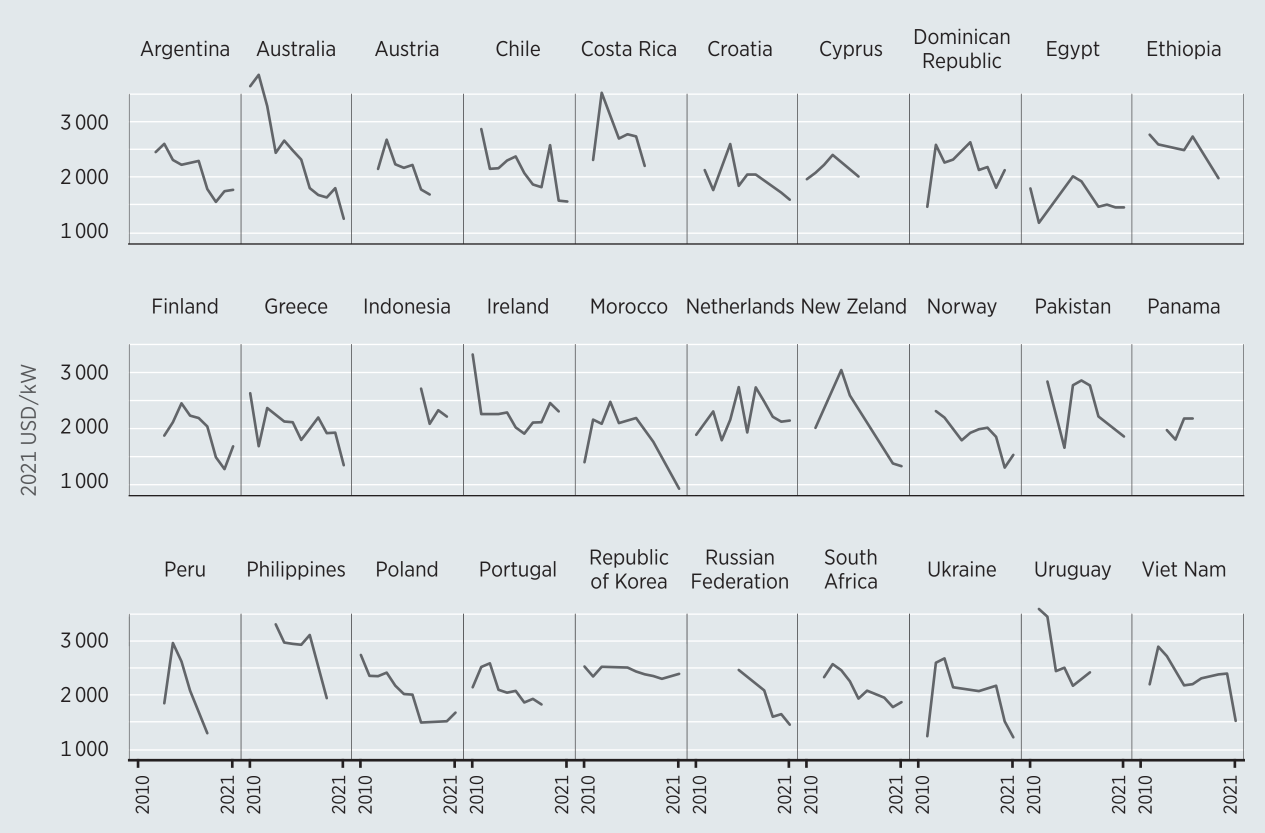
China, Brazil and India have more mature markets and lower cost structures than their neighbours. This can be seen in their lower average installed costs for onshore wind in 2021. India had the most competitive weighted average total installed costs that year, at USD 926/kW, with the country's installed costs falling 53% since 2010. Brazil and China had relatively similar weighted average total installed costs in 2021 – USD 1150/kW and USD 1157/kW, respectively. Between 2010 and 2021, these costs fell 58% in Brazil and 26% in China.

Table 2.1 Total Installed cost ranges and weighted averages for onshore wind projects by country/region, 2010 and 2021

	2010			2021		
	5th percentile	Weighted average	95th percentile	5th percentile	Weighted average	95th percentile
	(2021 USD/kW)					
Africa	1 440	**1 667**	3 145	1 149	**1 892**	2 924
Central America and the Caribbean	2 618	**2 776**	2 922	1 583	**1 583**	1 583
Eurasia	2 534	**2 534**	2 534	888	**1 349**	1 738
Europe	1 832	**2 517**	3 671	1 127	**1 623**	2 182
North America	1 962	**2 563**	3 329	1 079	**1 388**	2 325
Oceania	3 176	**3 647**	4 010	1 136	**1 256**	1 371
Other Asia	1 920	**2 606**	2 860	1 232	**1 545**	2 260
Other South America	2 513	**2 739**	2 863	1 146	**1 663**	2 292
Brazil	2 461	**2 734**	3 008	842	**1 150**	1 960
China	1 311	**1 554**	1 819	968	**1 157**	1 514
India	927	**1 415**	1 673	755	**926**	1 057

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

Figure 2.6 Onshore wind weighted average total installed costs in smaller markets by country, 2010-2021



Source: IRENA Renewable Cost Database.

CAPACITY FACTORS

The capacity factor represents the annual energy output from a wind farm, expressed as a percentage of the farm's maximum output. It is predominantly determined by two factors: the quality of the wind resource where the wind farm is sited; and the turbine and balance-of-plant technology used.

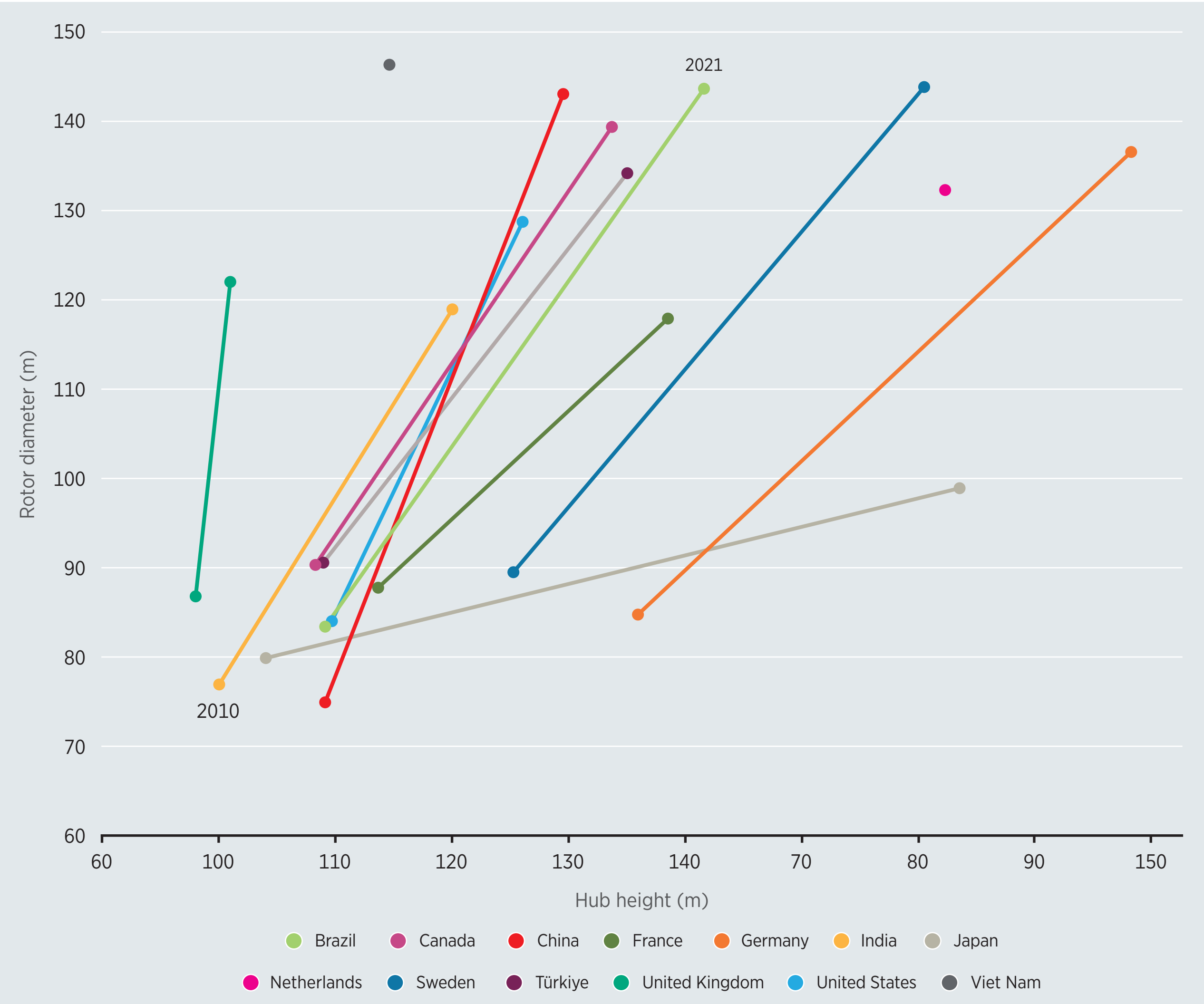
Figure 2.7 shows the trend in hub heights and rotor diameters in major markets between 2010 and 2021 for which data is available. Most markets saw significant increase in both parameters, although there are exceptions to this, notably for Japan.

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. Indeed, the global weighted average capacity factor for onshore wind increased by 95% between 1983 and 2021, from around 20% in the former year to 39% in the latter. This upward trend was also observed during the 2010 to 2021 period. During that decade, there was an almost one-third increase in the capacity factor, from just over 27% to 39%. Between 2019 and 2020, the capacity factor remained at 36%.

The increase in the global weighted average capacity factor for onshore wind in 2021 was driven by increased deployment in countries and regions with excellent wind resources, that year notably in the United States and Latin America. Alongside this was a significant decline in China's share of global deployment that year. China deployed 69 GW of onshore wind in 2020, a total that fell by 58% in 2021, to 29 GW. These two factors had a significant impact on the global weighted average capacity factor, in addition to the impact of continued technology improvements, larger turbines, higher hub heights, and larger swept areas. Resource quality also has a significant impact on the capacity factor, even though technology improvements have raised output across the board.

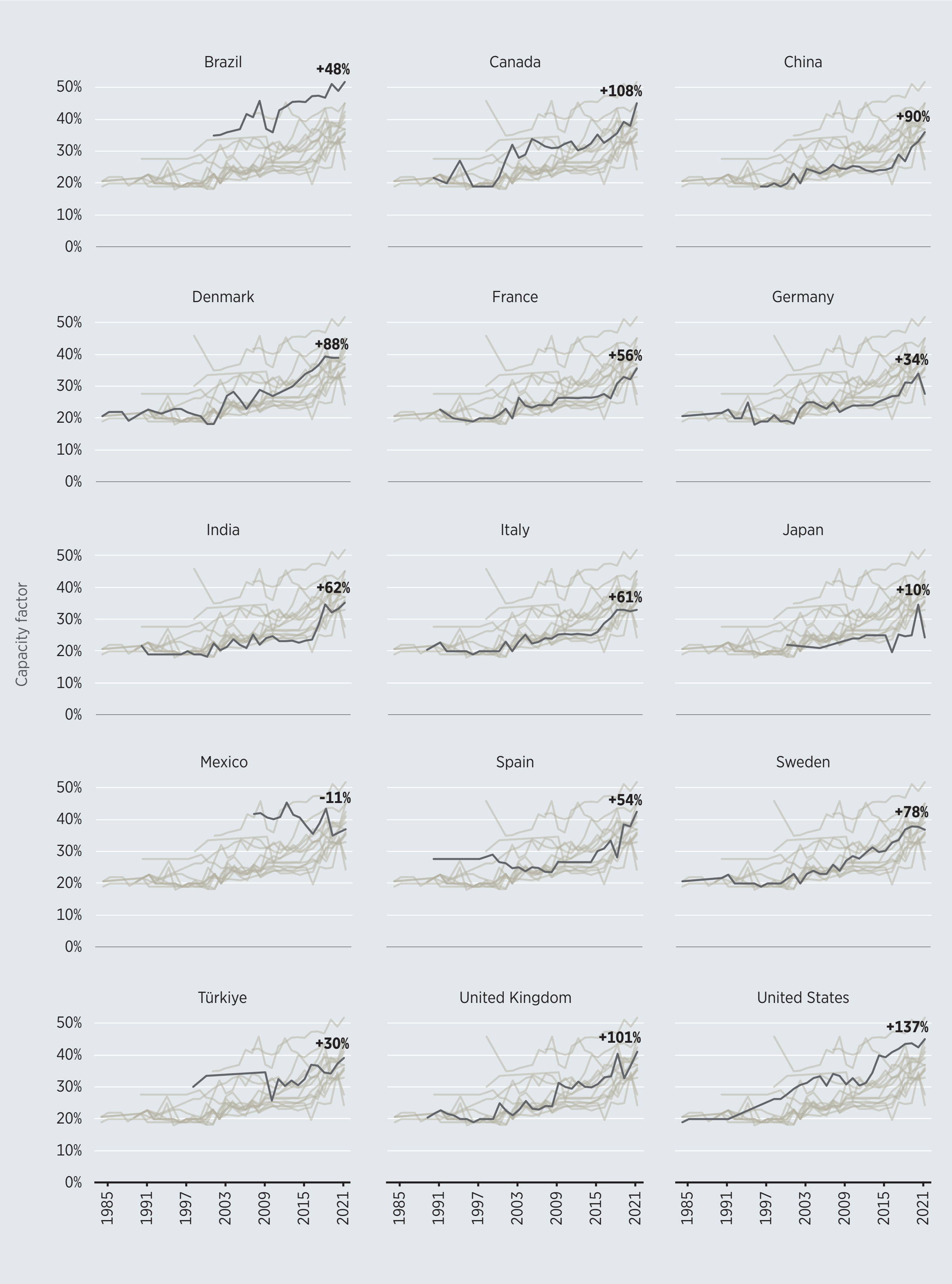
There is, therefore, still wide variation in the capacity factor across markets. While this is predominantly due to differing wind resource qualities, it is also, to a lesser extent, due to the different technologies used and different site configurations. Not all capacity factor improvements are the result of turbine technology improvements, either, as – owing to advances 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 2.7 Onshore wind weighted average turbine rotor diameter and hub height by country, 2010-2021



Source: IRENA Renewable Cost Database.

Figure 2.8 Historical onshore wind weighted average capacity factors in 15 countries, 1984-2021



Source: IRENA Renewable Cost Database.

Figure 2.8 depicts the historical evolution of onshore wind capacity factors for newly commissioned projects[45] in each year across the 15 markets where IRENA has the longest time series data.

The figure shows that average capacity factors increased by just over half for the 15 countries examined. Granted, there are varying start dates for commercially deployed projects, but nonetheless, this shows the scale of capacity factor improvements. In the United States, for example, between 1984 – when the earliest project was commissioned – and 2021, capacity factors increased 137%. Elsewhere, in Canada, China, Denmark and the United Kingdom, capacity factors increased by more than 80% between their earliest deployment dates and 2021. Brazil, like the United States, has excellent onshore wind resources and in 2021, newly commissioned projects in the South American country had the highest weighted average capacity factor amongst the 15 countries examined, at 52%.

Table 2.2 shows more recent changes in capacity factors for projects commissioned in the same 15 countries for the 2010 to 2021 period. Except for Mexico and Japan, all the countries experienced improvements in their weighted average capacity factors, with an increase of between 15% in Germany and 59% in Spain.

Table 2.2 Country-specific average capacity factors for new onshore wind, 2010 and 2021

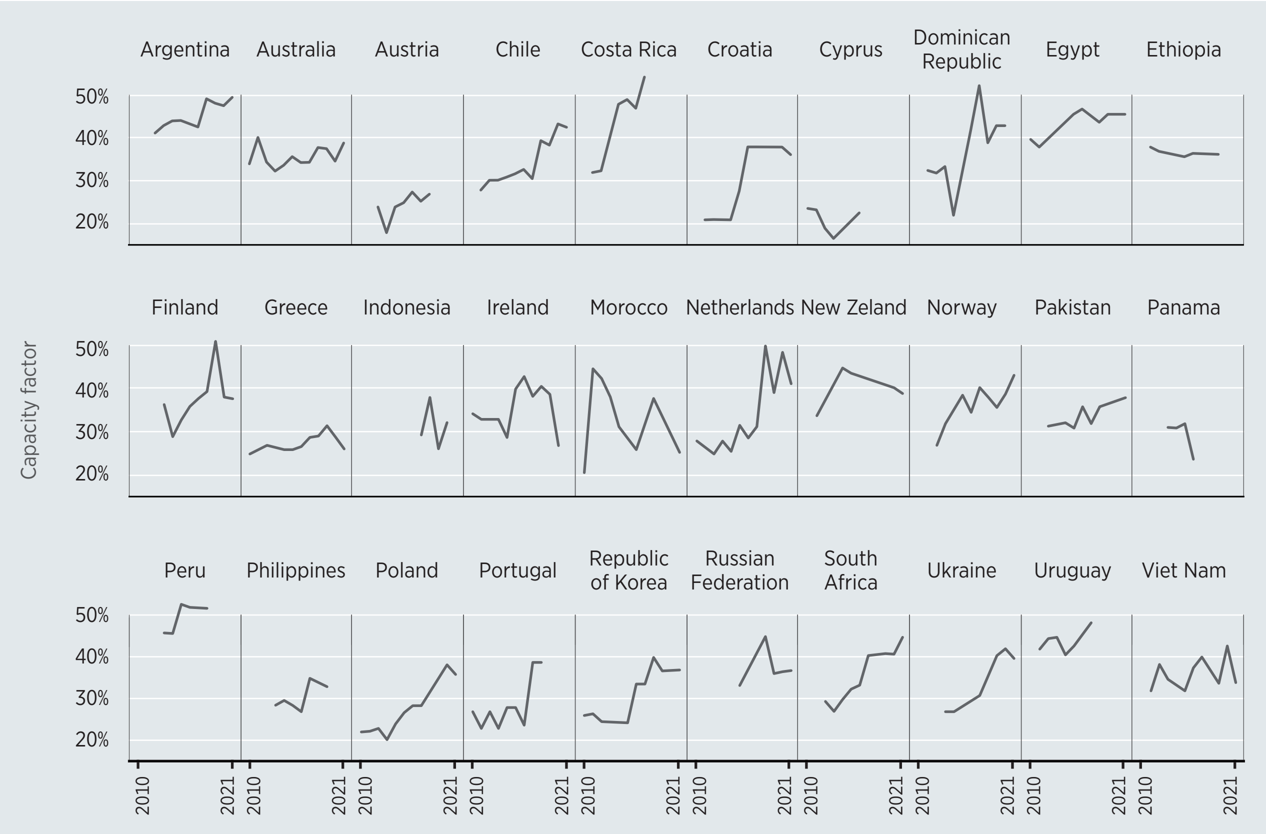
	2010	2021	Percentage change 2010-2021
	%		
Brazil	36	52	44
Canada	32	45	39
China	25	36	42
Denmark*	27	39*	44
France	26	36	35
Germany	24	28	15
India	25	35	42
Italy	25	33	30
Japan	24	24	-
Mexico	40	37	-8
Spain	27	43	59
Sweden	29	37	29
Türkiye	26	39	52
United Kingdom	30	41	37
United States	33	45	37

Source: IRENA Renewable Cost Database.

** Countries with data only available for projects commissioned in 2020.*

[45] *The capacity factors for newly commissioned projects are the ex-ante reported lifetime capacity factors expected by the project developer. Actual out will vary each year given on the relative wind conditions and the overall lifetime capacity factor may differ from the anticipated value.*

Figure 2.9 Onshore wind weighted average capacity factors for new projects in smaller markets by country and year, 2010-2021



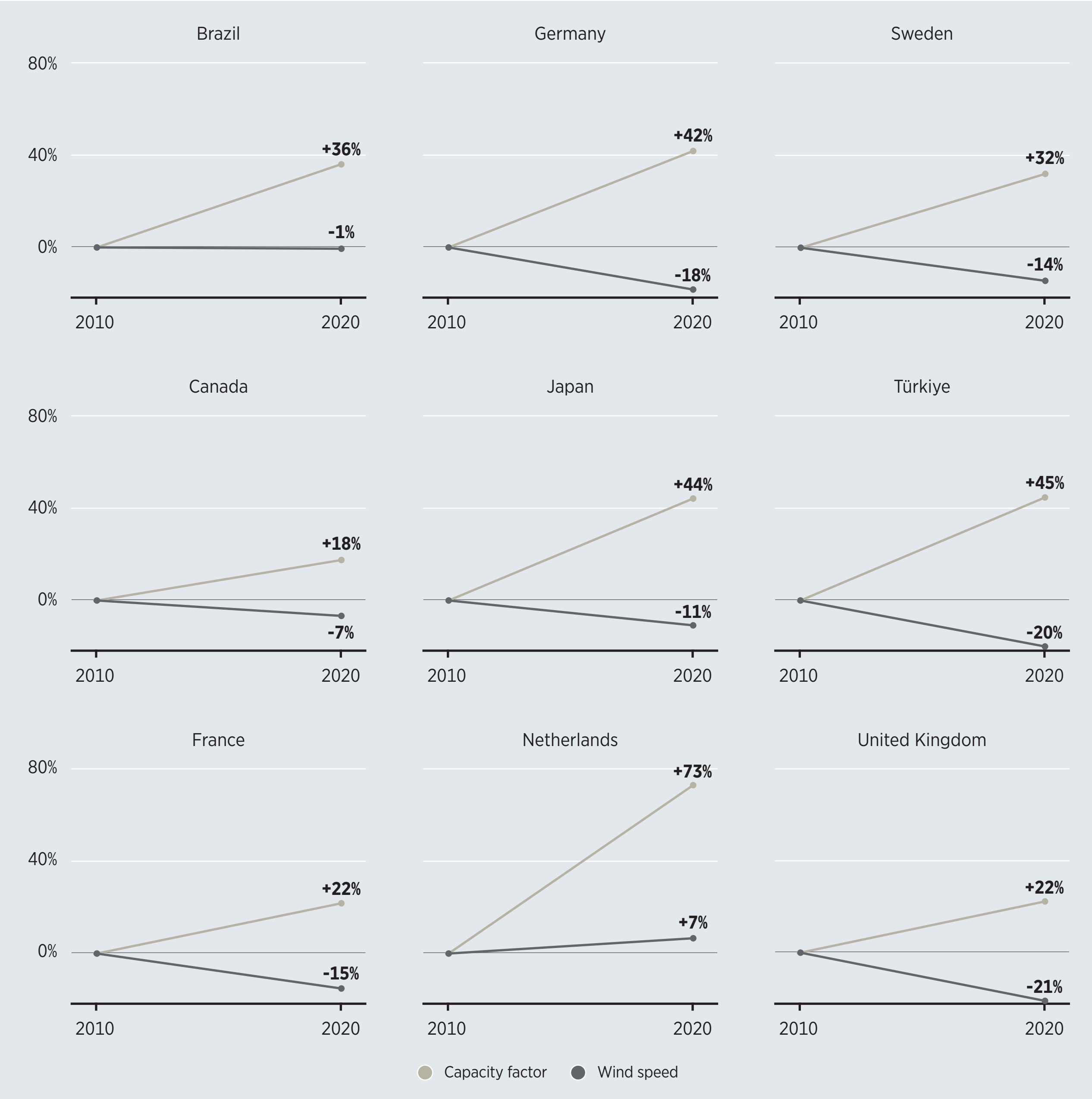
Source: IRENA Renewable Cost Database.

Figure 2.10 shows that the countries examined experienced an increase in their weighted average capacity factors for new projects commissioned in 2020 compared to those in 2010, despite a decline in the weighted average wind speed of the projects for which IRENA has data.[46] The latter decline in wind speed for new projects could be due to less access to better wind resources in some countries, but also in some markets might be the result of the improved economics of onshore wind allowing for projects in areas with lower wind speeds that were previously considered uneconomic. The overall trend across these markets confirm that technology improvements, including larger turbines and longer blades with higher hub heights, contributed greatly to an increase in the global weighted average capacity factor.

Amongst the nine countries examined below, the highest weighted average capacity factor increase was in the Netherlands, at 73%, followed by Türkiye and Japan, which saw increases of 45% and 44%, respectively. France and the United Kingdom both showed an increase of 22% in their weighted average capacity factors, while Canada had the lowest weighted average capacity factor increase, at only 18%. The results, despite being for a subset of new projects, suggest that the increase in capacity factor between 2010 and 2020 underestimates the contribution of technology innovation and improvements in increasing wind farm yields (IRENA, 2022b).

[46] *The analysis is based on the mean wind speed of the project site, taking into account hub-heights, for newly commissioned projects in the specified year. It is not an analysis of how wind speeds at a given project site have changed over time.*

Figure 2.10 Change in the weighted average capacity factor and wind speed for new projects by country between 2010 and 2020



Source: IRENA Renewable Cost Database.

Note: The number of projects for which IRENA has sufficient data to do the analysis contained in this figure is a sub-set of the total project data. The results are therefore indicative, and the percentage changes in capacity factor in this figure are not the same as the annual weighted average capacity factor as reported in Figure 2.8.

OPERATION AND MAINTENANCE COSTS

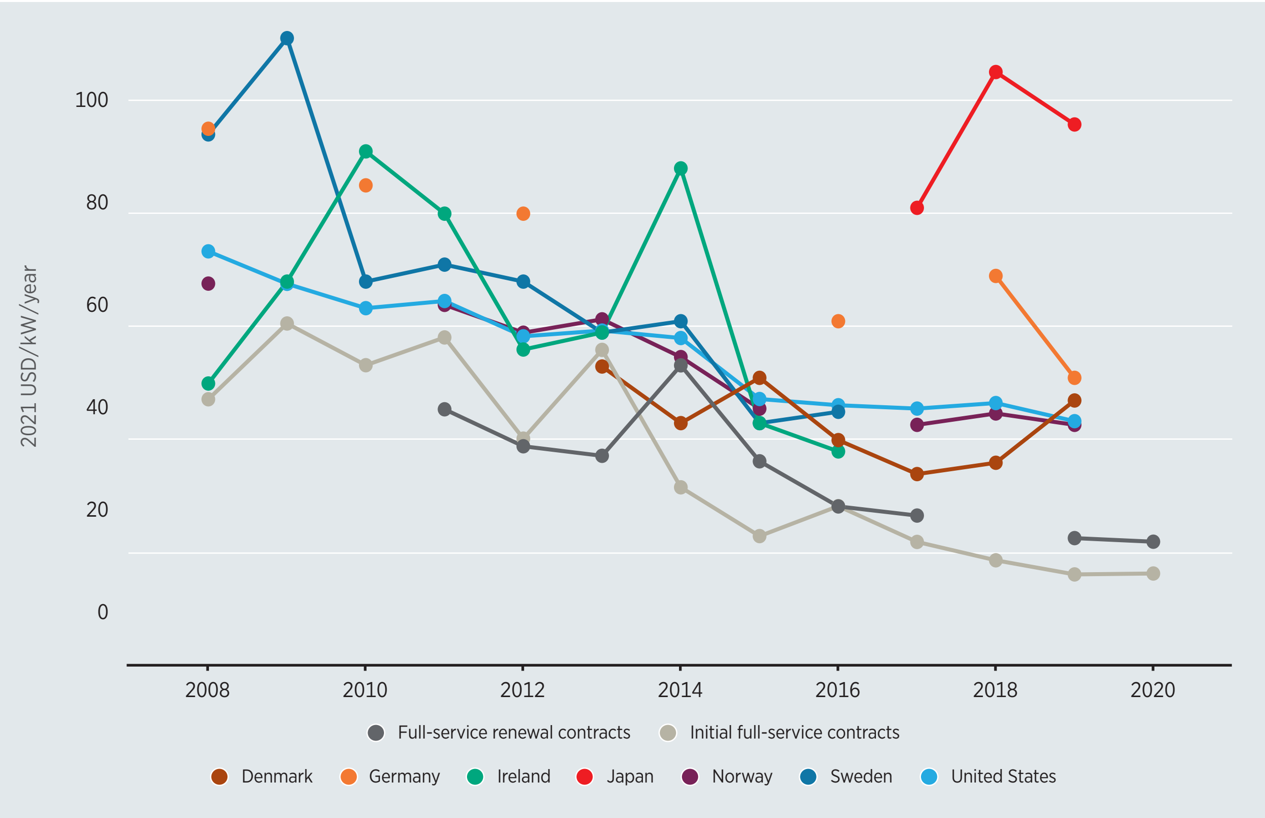
O&M costs for onshore wind often make up as much as 30% of the LCOE for this technology (IRENA, 2018). Technology improvements, greater competition among service providers, and increased operator and service provider experience are, however, driving down O&M costs. This trend is being supported by increased efforts by turbine OEMs to secure service contracts, as such agreements can provide higher profit margins than those from turbine supply alone (BNEF, 2020c; Wood MacKenzie, 2019).

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

Figure 2.11 shows O&M costs in selected countries, along with Bloomberg New Energy Finance (BNEF) O&M price indexes. The latter are represented as either initial full-service contracts or full-service contracts for already established wind farms. The latter 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 ranged from USD 33/kW per year in Denmark to USD 56/kW per year in Germany – a country 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, and other factors).

Figure 2.11 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, 2020c and 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. Yet, while all of these factors are important in determining the LCOE of a project, some components have a larger impact than others. 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.

In 2020, the O&M costs, comprising fixed and variable components, made up between 10% and 30% of the LCOE 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 current low levels.

Figure 2.12 presents the evolution of the LCOE (global weighted average and project level) of onshore wind between 1984 and 2021. Over that period, the global weighted average LCOE declined by 90%, from USD 0.320/kWh to USD 0.033/kWh. In 2010, the LCOE was USD 0.102/kWh, meaning there was a 68% decline over the decade to 2021. Consequently, onshore wind now increasingly competes with hydropower as the most competitive renewable technology, without financial support.

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

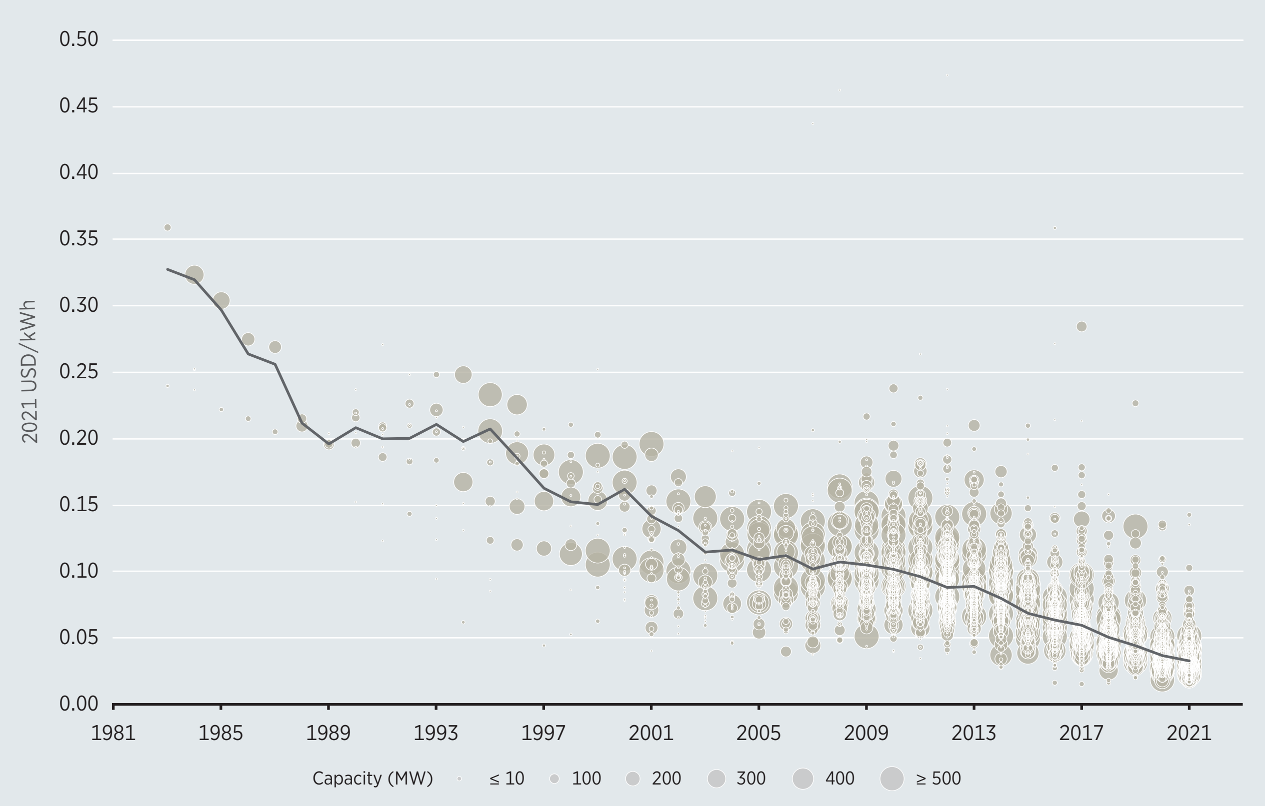
Turbine technology improvements: With the increase in turbine sizes and swept areas, the process of optimising the rotor diameter and turbine ratings, *i.e.* the specific power, has led to increased energy yield and thus project viability for the asset owner, depending on site characteristics. In addition, 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, O&M costs, and installation, given the reduction in the number of turbines required for a project due to higher turbine ratings.

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 have been entering the O&M servicing sector for onshore wind, which is increasing competition and driving down costs (BNEF, 2019, 2020a).

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

Figure 2.12 LCOE of onshore wind projects and global weighted average, 1984-2021

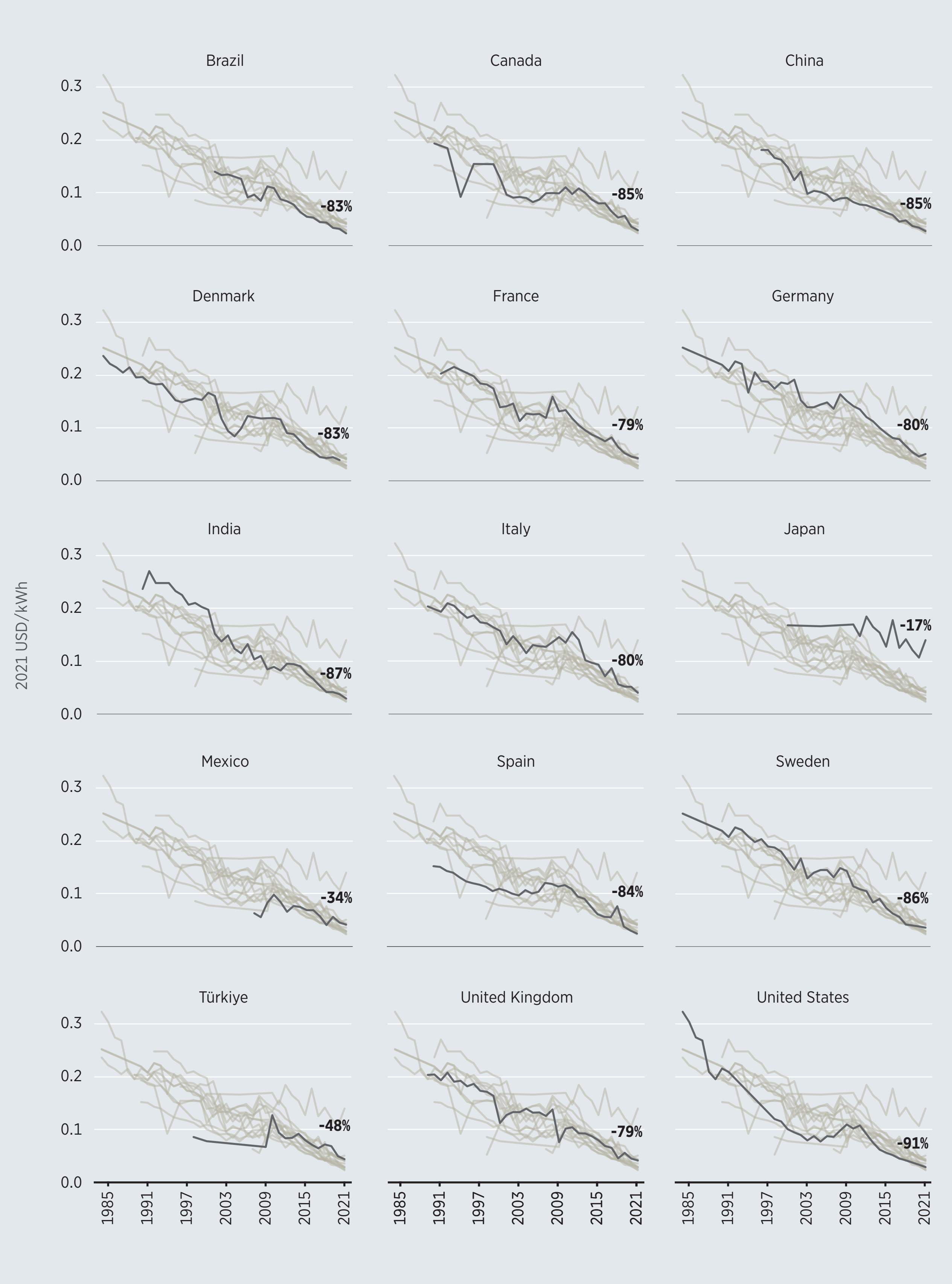


Source: IRENA Renewable Cost Database.

The growing maturity of the onshore wind market (cumulative deployment grew by 759 GW between 2000 and 2021) should also not be overlooked. Increased operational experience and favourable government regulations and policies have reduced project development and operational risks for onshore wind, especially in established markets. These risks are now better understood, with adequate mitigation measures in place.

Figure 2.13 presents the historical evolution of the LCOE of onshore wind in 15 countries where IRENA has the longest time series data. This data should be interpreted with care, however, as cross-country comparisons are problematic given 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 (91%) was in the United States, which had the second largest reduction (73%) in average total installed costs, while it also saw a 137% improvement in its average capacity factor. India and Sweden had the second and third largest weighted average LCOE reductions, at 87% and 86%, respectively, followed by China and Canada, which both had a weighted average LCOE reduction of 85%. In 2021, with the exception of Japan, all the 15 countries analysed in Figure 2.13 had weighted average LCOEs below USD 0.054/kWh – the lower range for fossil fuel-fired power generation.

Figure 2.13 The weighted average LCOE of commissioned onshore wind projects in 15 countries, 1984-2021



Source: IRENA Renewable Cost Database.

Table 2.3 shows the country/region weighted average LCOE and 5th and 95th percentile ranges by region in 2010 and 2021.

In 2021, the highest weighted average LCOE for commissioned projects by region was USD 0.050/kWh in the 'Other South America' category (*e.g.* South America excluding Brazil), while projects commissioned in Brazil and China saw the lowest weighted average LCOEs, at USD 0.024/kWh and USD 0.028/kWh, respectively. The highest LCOE reductions between 2010 and 2021 were in Brazil, which saw them fall by 78% (USD 0.109/kWh to USD 0.024/kWh). Oceania had the second highest LCOE reduction for the same period, at 75%, the United States had a reduction of 70% and Europe and 'Other Asia' (*i.e.* Asia excluding China and India) had a reduction of 68%.

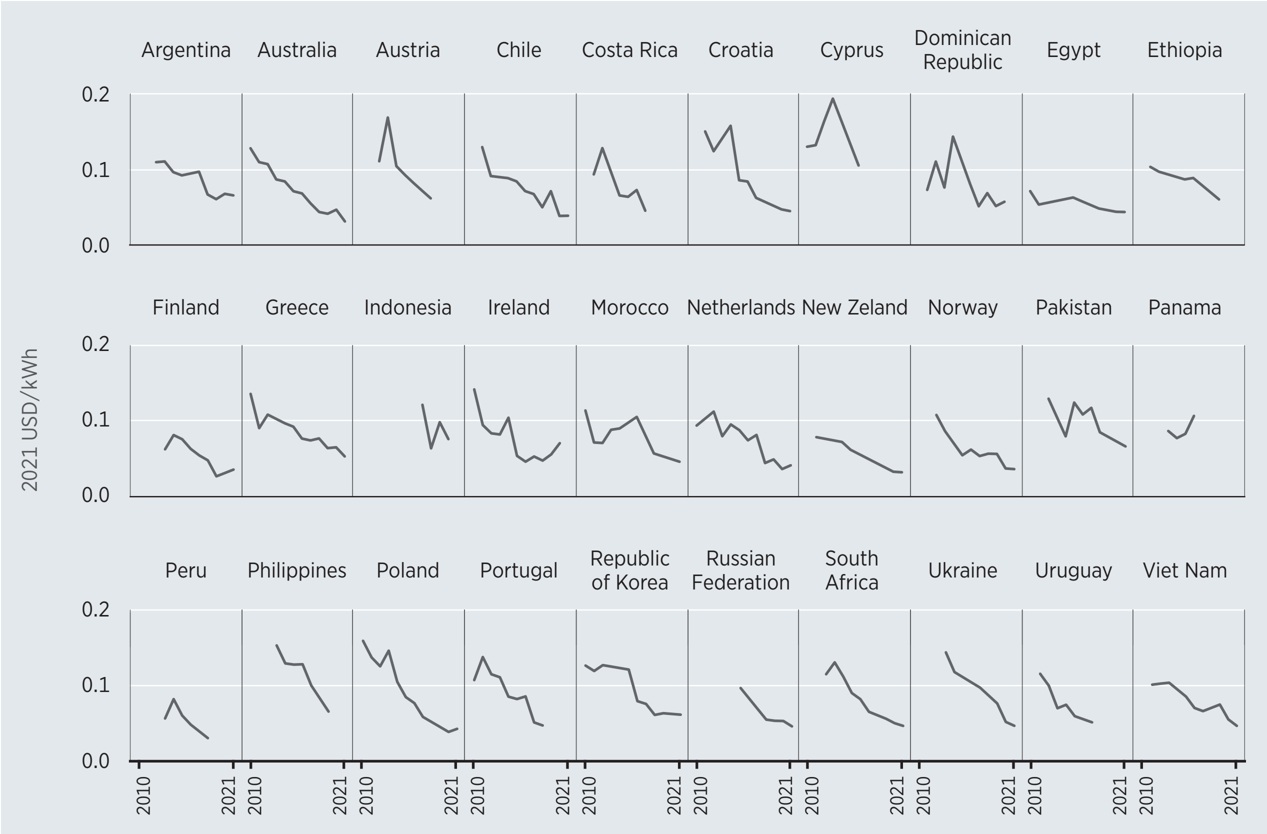
Wind power projects are increasingly achieving LCOEs of less than USD 0.040/kWh, and in some cases, as low as USD 0.030/kWh. The most competitive weighted average LCOEs below USD 0.050/kWh were observed across different regions: in Asia (India and China), Europe (Finland and Sweden), Africa (Egypt), North America (the United States), and South America (Argentina and Brazil). Considering LCOE ranges regionally, in 2021, the 5th and 95th percentile range for the global weighted average LCOE was between USD 0.018/kWh in Brazil and USD 0.084/kWh in 'Other South America'.

Table 2.3 Regional weighted average LCOE and ranges for onshore wind in 2010 and 2021

	2010			2021		
	5th percentile	Weighted average	95th percentile	5th percentile	Weighted average	95th percentile
	(2021 USD/kW)					
Africa	0.070	**0.097**	0.111	0.041	**0.049**	0.079
Central America and the Caribbean	0.091	**0.091**	0.091			
Eurasia	0.128	**0.128**	0.128	0.029	**0.045**	0.071
Europe	0.086	**0.130**	0.195	0.026	**0.042**	0.059
North America	0.066	**0.103**	0.140	0.024	**0.031**	0.055
Oceania	0.114	**0.129**	0.140	0.026	**0.032**	0.040
Other Asia	0.107	**0.148**	0.160	0.038	**0.048**	0.074
Other South America	0.090	**0.105**	0.136	0.034	**0.050**	0.084
Brazil	0.109	**0.109**	0.109	0.018	**0.024**	0.036
China	0.067	**0.083**	0.104	0.020	**0.028**	0.038
India	0.055	**0.090**	0.113	0.023	**0.030**	0.034

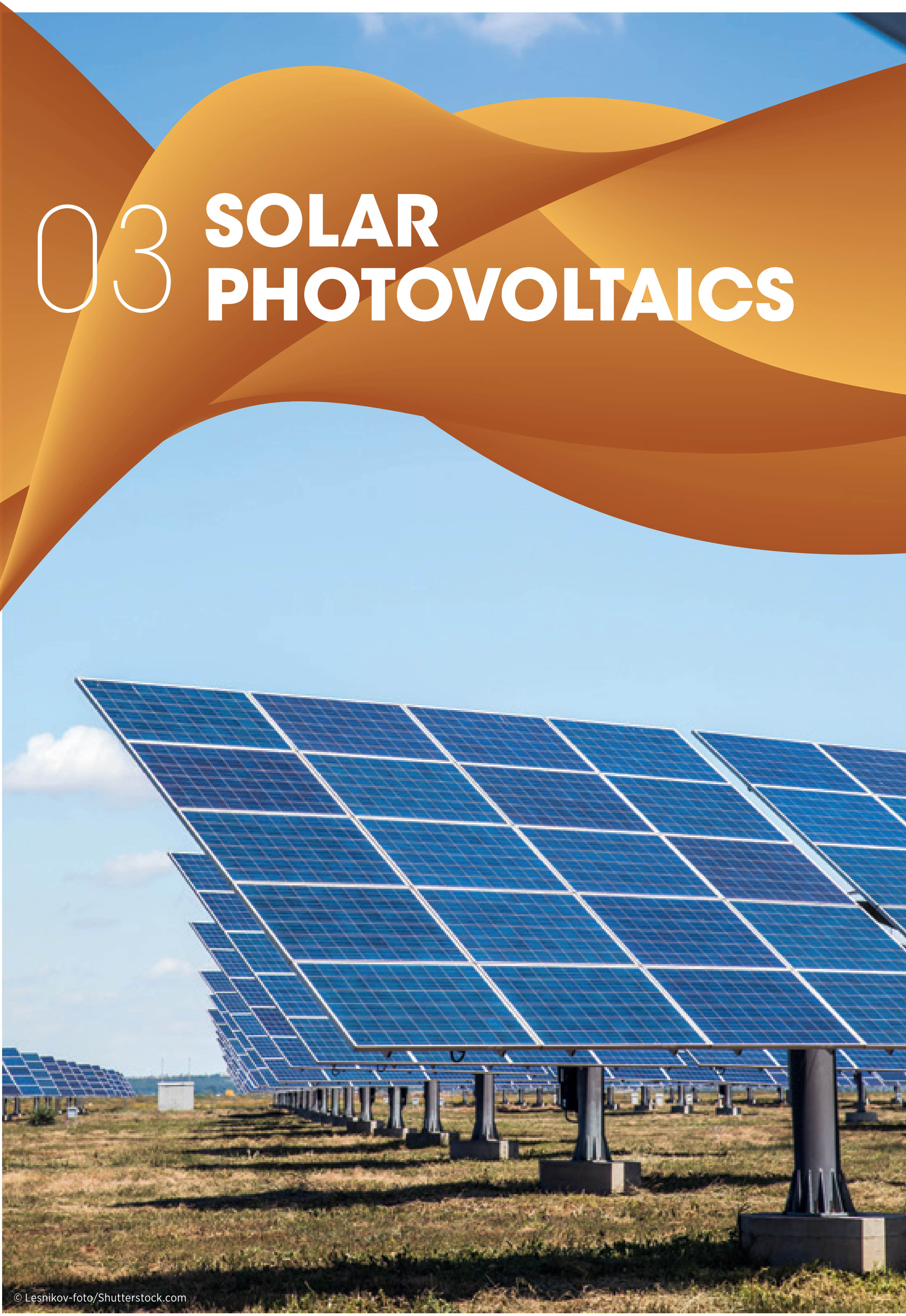
Source: IRENA Renewable Cost Database.

Figure 2.14 Onshore wind weighted average LCOE in smaller markets by country and year, 2010-2021



Source: IRENA Renewable Cost Database.

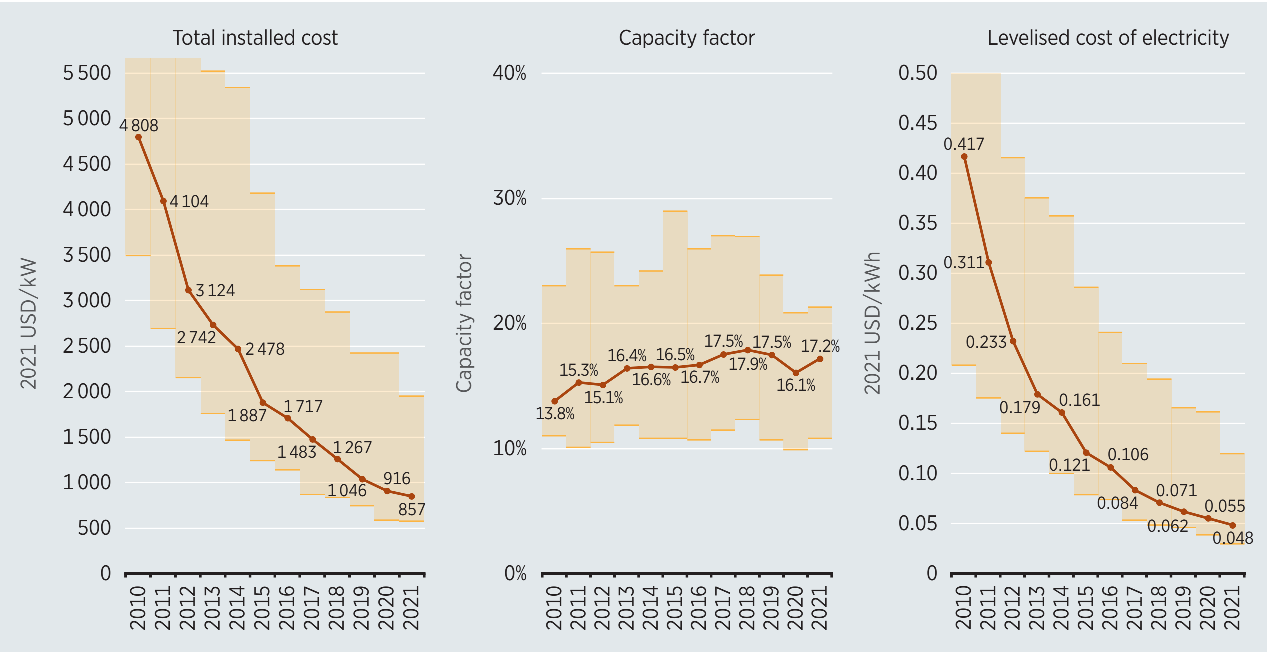
03 SOLAR PHOTOVOLTAICS



HIGHLIGHTS

- The global weighted average levelised cost of electricity (LCOE) of utility-scale photovoltaic (PV) plants declined by 88% between 2010 and 2021, from USD 0.417/kilowatt hour (kWh) to USD 0.048/kWh. In 2021, the year-on-year reduction was 13%.
- At an individual country level, the weighted average LCOE of utility-scale solar PV declined by between 75% and 90% between 2010 and 2021.
- The cost of crystalline solar PV modules sold in Europe declined by around 91% between December 2009 and December 2021.
- The global capacity weighted average total installed cost of projects commissioned in 2021 was USD 857/kilowatt (kW), 82% lower than in 2010 and 6% lower than in 2020.
- Solar PV capacity grew about 21-fold between 2010 and 2021, with over 843 GW installed by the end of 2021.
- On average, in 2020, balance of system (BoS) costs (excluding inverters) made up about 57% of total installed costs.
- The global weighted average capacity factor for new, utility-scale solar PV increased from 13.8% in 2010 to 17.2% in 2021. 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 solar PV's use in more latitudes.

Figure 3.1 Global weighted average total installed costs, capacity factors and LCOE for PV, 2010-2021



Source: IRENA Renewable Cost Database.

RECENT MARKET TRENDS

By the end of 2021, over 843 GW of solar PV systems had been installed, worldwide. This represented almost 21-fold growth for the technology since 2010. About 133 GW of newly installed systems was commissioned during 2021 alone (13% more than in 2020). 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 2021 was driven by continued new capacity additions in that region, when Asia contributed about 57% of all new installations. Developments there were driven by China, which accounted for around 70% of all new Asian (and about a 40% of all global) installations.

During 2021, PV installations in India more than doubled compared to 2020. Indeed, taken together, India, Japan and the Republic of Korea contributed another 18.3 GW of new PV capacity in 2021 (a 37% increase on 2020).

Historical markets outside Asia also continued to gain scale. Compared to 2020, new capacity in the United States increased by more than a third. During 2021, the United States, Brazil and Germany together installed about 30 GW, while Spain and the Netherlands exceeded 3 GW each in new installations.

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 technology has shown the highest learning rates of all renewable energy technologies. Between December 2009 and December 2021, crystalline silicon module prices declined between 88% and 95% for modules sold in Europe, depending on the type. The weighted average cost reduction was in the order of 92% during that period. Between 2019 and 2020, the yearly average module price declined between 5% and 15% for crystalline modules. After several years of a downward price trend, however, for crystalline modules, the yearly average price between 2020 and 2021 increased between 4% and 7%. This trend reversal was driven by supply chain disruptions during 2021 that led to higher material costs or lower availability, pushing up prices (Box 3.1).

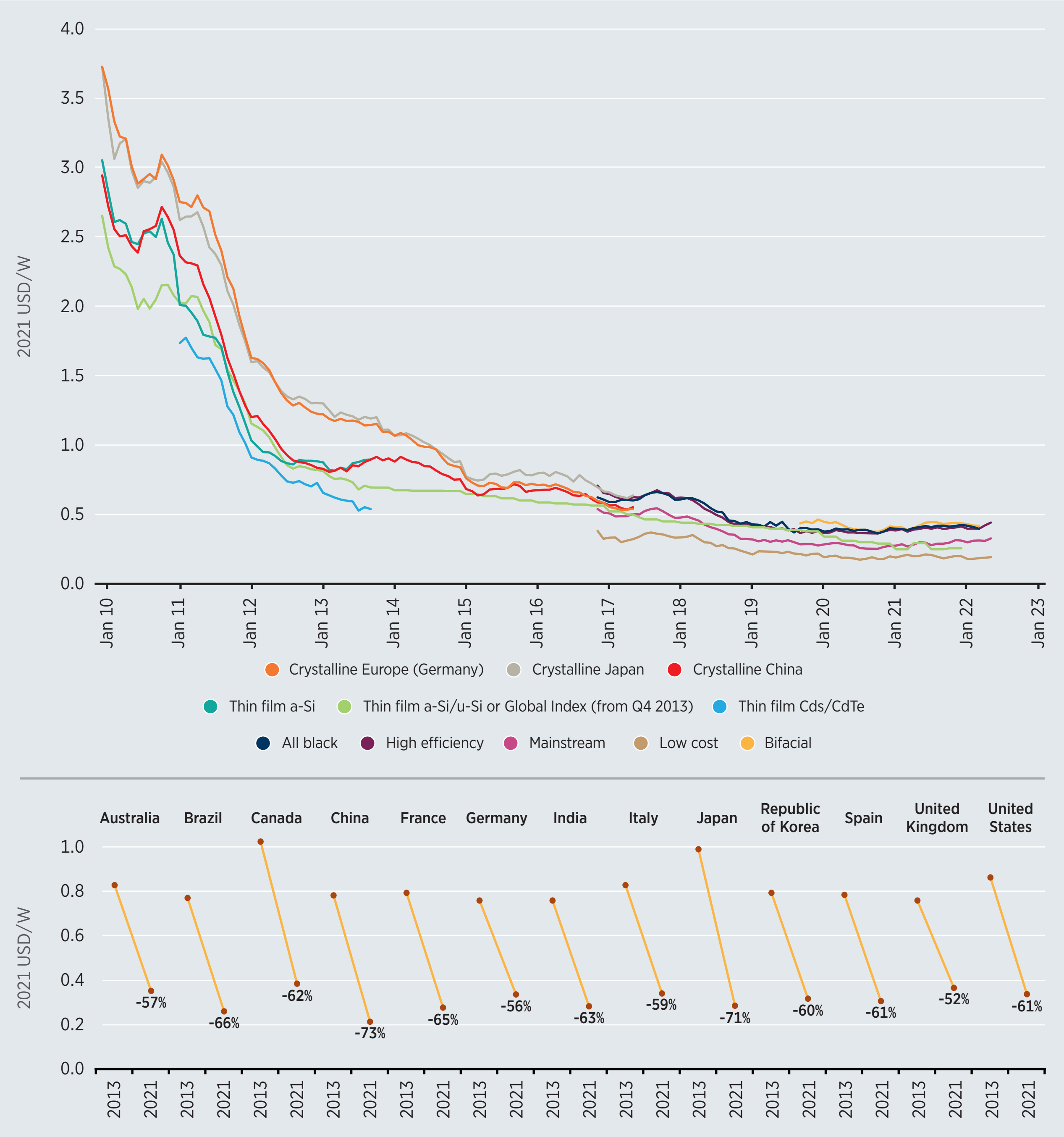
Between December 2009 and December 2021, crystalline silicon module prices declined by between 88% and 95%

During December 2021, mainstream modules sold for USD 0.32/watt (W). A wide range of costs exists, however, depending on the module technology considered. Costs varied from as low as USD 0.20/W for the lower cost modules to as high as between USD 0.42 and USD 0.44/W for high efficiency, all black and bifacial modules. This cost range is between 0% and 5% higher than it was during December 2020.

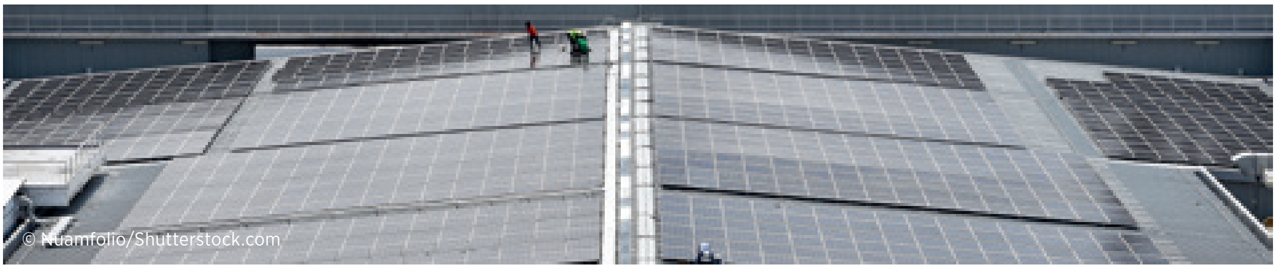
Thin film offerings sold for USD 0.26/W during December 2021, after seeing a cost decline of 12% between December 2020 and December 2021. The cost of crystalline bifacial modules increased 5% during the same period. Bifacial crystalline modules sold 21% higher than high efficiency, monofacial modules during December 2019. This cost premium fell to 6% during December 2020 and to 5% during December 2021. It points to bifacial module costs being more driven by the cost of the cell architecture 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 around 27% during 2020 (ITRPV, 2022).

Between 2013 and 2020, market-level module costs declined by between 52% (the United Kingdom) and 73% (China) for those markets for which historical data is available. Indeed, data for 2021 shows that a wide range of module costs still exists among the markets evaluated, although, despite the supply chain troubles of the industry that year compared to 2020 (see Box 3.1), the cost range did narrow, from USD 0.23/W to USD 0.17/W. During 2021, the highest module cost was 1.8 times the lowest in the markets assessed (compared to about three times higher in 2018). Where module cost reductions from 2020 occurred in the assessed markets, however, they ranged between 14% (Canada) and 19% (China). This compared to a range of between 2% and 38% reduction in 2020, year-on-year. At the same time, a module cost increase of between 10% (UK) and 40% (Germany) occurred in all assessed markets between 2019 and 2020 (Figure 3.2).

Figure 3.2 Average monthly solar PV module prices by technology and manufacturing country sold in Europe, 2010 to 2021 (top) and average yearly module prices by market in 2013 and 2021 (bottom)



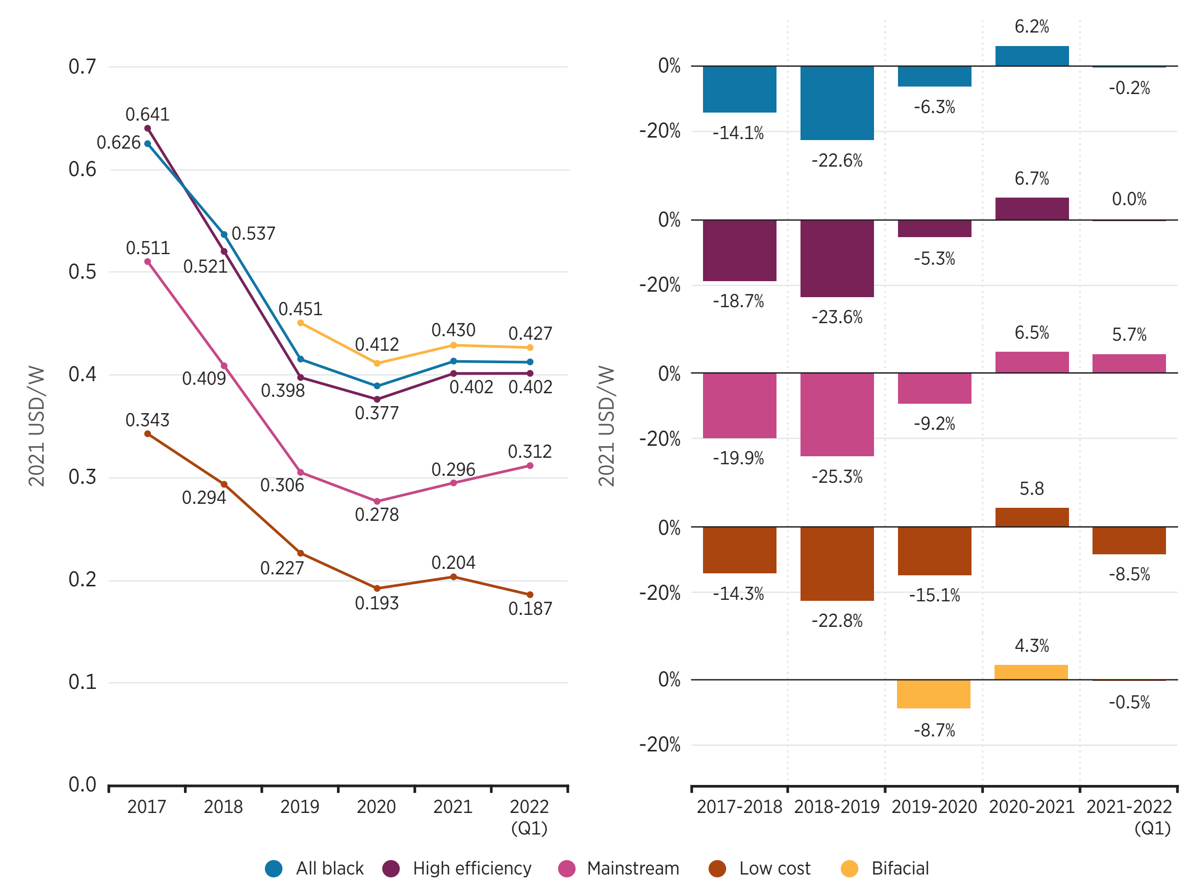
Source: GlobalData (2022); pvXchange (2022); Photon Consulting (2017); IRENA Renewable Cost Database.



Box 3.1 Recent uptick in solar PV module costs

After a decade of continuous decline, in 2021, solar PV module prices climbed as supply chain disruptions led to higher material costs, or lower availability. Taking modules sold in Europe as a reference, these developments meant that the price of crystalline solar PV modules increased between 4% and 7% in 2021 compared to 2020, from a range of between USD 0.19/W and USD 0.41/W to between USD 0.20/W and USD 0.43/W. An analysis of data from Q1 2022 suggest that prices have now stabilised and have started to decline for low cost offerings, though they remain at 2019 levels for suggests mainstream products.

Figure B3.1 Average yearly solar PV module prices by technology sold in Europe, 2010 to 2021 and 2022 Q1. Average (left) and percentage increase (right)



Source: Source: GlobalData (2022); pvXchange (2022); Photon Consulting (2017); IRENA Renewable Cost Database.

The reasons for the 2021 price uptick are varied, but a systemic contributor to this increase has been the rising price of polysilicon. Challenges related to available polysilicon capacity in China pushed polysilicon prices from around USD 11/kilogram (kg) at the beginning of 2021 to over USD 30/kg towards the end of that year, as cell manufacturers raced to secure supplies, bidding up prices.

Polysilicon prices now are stabilising, however. This has happened due to industry-wide efforts to scale up production through manufacturing capacity expansions, while further technology improvements in manufacturing have also started to pay off. The risk still exists, though, that supply may again suffer due to maintenance overhauls that may result in lower-than-expected output. It remains unclear when polysilicon prices might return to a lasting downward trend.

Silicon costs remain the main driver for PV module costs, but the challenging economic environment of 2021 also saw surging costs for other commodities utilised in PV module manufacture. Rising silver, copper, aluminium and glass costs, alongside price rises in other cost inputs, such as electricity and other energy sources, also played a role. This meant that the industry's continued effort in processing innovation and reducing material utilisation often did not suffice in sustaining the cost declines shown in previous years.

This effect was also exacerbated by other pandemic-related logistics and global-freight and shipping challenges. These resulted in an inflationary effect across the board in transportation, as did individual market policy decisions – such as the prioritisation of local market production in China and import checks in some markets such as the US. In the longer term, however, as the cost of commodities starts to stabilise with more balanced supply-demand circumstances, increasing efficiencies, further manufacturing optimisation and design innovation can be expected to more than offset the current temporary cost increase, resulting in PV module costs declining once again.

Various factors are expected to continue to contribute to increasing solar PV technology's competitiveness in the longer-term, the continued improvement of efficiency, manufacturing optimisation and design innovation are expected to more than offset the recent temporary cost increase. An example of this is the further adoption of bifacial technologies built from increasingly efficient cells, which is expected to continue. The average module efficiency of crystalline modules increased from 14.7% in 2010 to 20.9% in 2021. That rise was driven by a market shift from multi-crystalline to more efficient monocrystalline products, while passivated emitter and rear cell (PERC) architectures became state-of-the-art module technology.

The efficiency of PERC modules, however, is expected to grow towards 22% in the next few years, approaching its limits. In terms of cell architecture beyond PERC, likely candidates to drive efficiencies higher take two main approaches: first, a focus 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. These technologies are also expected 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 from 156 millimetres (mm) to 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 cells. 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 mm to 210 mm in 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 2022; Lin, 2019).

The sustainability of the materials used in solar PV modules is gaining in importance as the market continues to grow globally. Technological developments related to this are becoming the focus of many industry efforts, particularly in lieu of the 2021 supply chain constraints and the related supply/demand imbalances affecting manufacturing and shipping of solar PV modules and other system components.

Polysilicon consumption reduction remains as relevant as ever in this context, and industry efforts continue in this regard. For example, improved wafer sawing technologies, notably diamond wire sawing (DWS), have taken over from earlier slurry-based wafer sawing, contributing to reduced polysilicon use in the wafering step. The amount of polysilicon lost during cutting the wafers (kerf loss) has also declined. During 2021, kerf loss values of 60 micromets (μm) were already typical (a decline of more than 62% from 2010).

Wafer thickness is another important way to reduce polysilicon consumption. Reducing this at the speed the industry had hoped for mid-decade has, however, proved challenging because improvements in light trapping strategies, often could not compensate for current loss in thinner wafers. In the past, the industry favoured cheaper, thicker wafers over thinner wafers to maintain high current values and reduce production line breakage and overall costs. Using thinner wafers to further decrease costs, however, is becoming more important in the current market situation. After stagnating for a long time at 180 μm, recent progress has been made in the as-cut wafer thickness of crystalline silicon wafers. Increased automation in wafer and cell handling has enabled very low breakage rates in new factories. During 2020, for M6 (166 mm^2 x 166 mm^2) wafers, as-cut thickness declined to 175 μm for p-type wafers (which make up about 90% of the market) and 160 μm for n-type wafers. Thickness values of 165 μm became standard for p-type wafers during 2021 (ITRPV, 2021; ITRPV 2022).

Besides the wafer itself, metallisation pastes that contain silver have been an important cost component in the wafer-to-cell process. Given the relatively high cost of silver recently, the industry has placed significant focus on different ways to reduce metal consumption in cells.

For mono-facial p-type cells, total silver remaining in the cells declined from 400 milligrammes (mg) per cell in 2009 to 90 mg/cell in 2020 – a decline of 80%. In 2020, bifacial p-type cells had slightly higher consumption, at 98 mg/cell. In n-type cells (HJT and TOPCon), silver is used for front and full rear side metallisation, leading to significantly higher silver consumption than in their p-type counterparts. In multi-busbar designs, cells go from having 3-5 busbars to having typically 12 much thinner busbars. In addition, the flat ribbon traditionally used for cell interconnection is replaced by round wire with a narrower diameter. This allows reduced finger width, potentially reducing silver usage. During 2021, total silver remaining in the cells in absolute mg/cell terms stayed flat compared to 2020 values. Such consumption translates to about 13.2 mg of silver/W at the cell level, assuming standard PERC architecture. Industry expectations are for this value to reach 7.5 mg/W within the next decade, which corresponds to about 60 mg/cell.

Copper is still envisioned as a metallisation substitute for silver, but technical challenges remain. These are related to adhesion, with rapid adoption not expected. Despite this, new copper-based concepts keep developing (Zhan *et al.*, 2021).

In addition, increased adoption of bifacial technology is an important driver for solar PV competitiveness, given its potential to provide higher yield per watt than 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,[47] 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% to 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 latitude range of competitive tracking PV plants.

Total installed costs

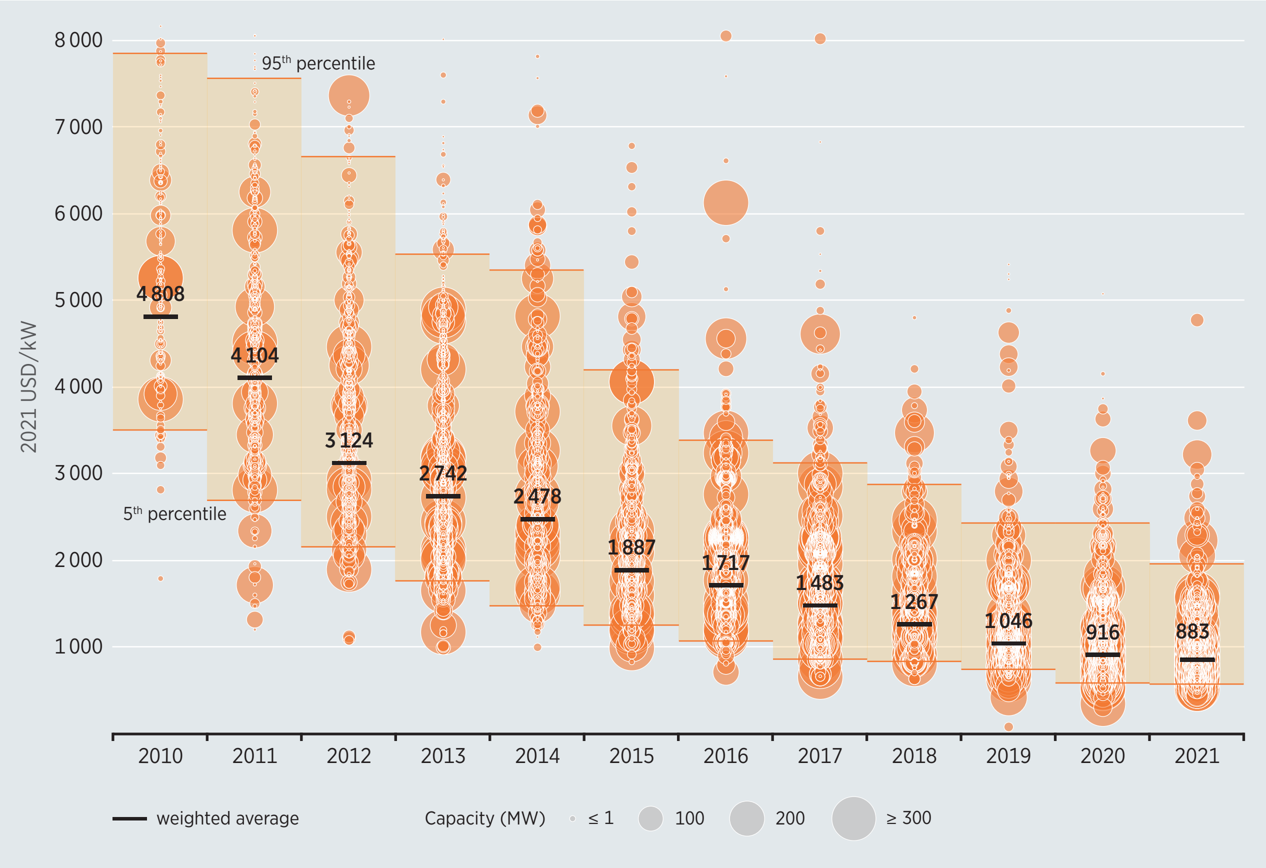
The global capacity weighted average total installed cost of utility-scale projects commissioned in 2021 was USD 857/kW (13% lower than in 2019 and 81% lower than in 2010). During 2021, the 5th and 95th percentile range for all projects fell within a range of USD 571/kW to USD 1 982/kW. The 95th percentile value was 18% lower than in 2020, while the 5th percentile value declined by 4% between 2020 and 2021. 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 5th and 95th percentile values were 84% and 75% lower, respectively (Figure 3.3).

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[48] costs have followed. This has led to an increased number of markets where PV systems are achieving competitive cost structures, with falling global weighted average total installed costs.

[47] *However, it is also possible to use bifacial cells in conventional opaque-backsheeted monofacial panels.*

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

Figure 3.3 Total installed PV system cost and weighted averages for utility-scale systems, 2010-2021



Source: IRENA Renewable Cost Database.

The market's supply chain disruptions during 2021, however, meant that the yearly cost reduction rhythm slowed down, compared to previous years. Despite this, total installed cost reductions of between 4% and 11% still occurred in 2021 across all the major historical markets, such as China, India, Japan, Korea, the United States and Germany. This compares to a broader 2020 year-on-year total installed cost decline of between 5% and 25% among these historical markets.

Projects with very competitive costs in India led to weighted average total installed costs of USD 590/kW in 2021, a value 6% lower than in China. This differential was 22% during 2019 and 8% in 2020. This results from Chinese costs having declined 19% between 2019 and 2020 and another 7% in 2021, compared to 5% in India in both 2020 and 2021. During the latter year, total installed costs in Germany declined 4% (a considerably lower reduction than the 23% decline that occurred during 2020). A similar trend could be observed in the Republic of Korea, where total installed costs also fell by 4% in 2021 after falling by a quarter between 2019 and 2020.

In Spain, some very competitive subsidy-free projects came online during 2020, but some of these very low costs could not be replicated in 2021, leading to a 3% increase in total installed costs. The weighted average total installed cost in Spain in 2021 was USD 916/kW, a value 18% higher than in Germany, though below the global weighted average.

In addition to this, competitive cost structures continue to prevail in more recently established markets, such as the Netherlands and Türkiye, where total installed costs declined 9% and 5% respectively between 2020 and 2021.

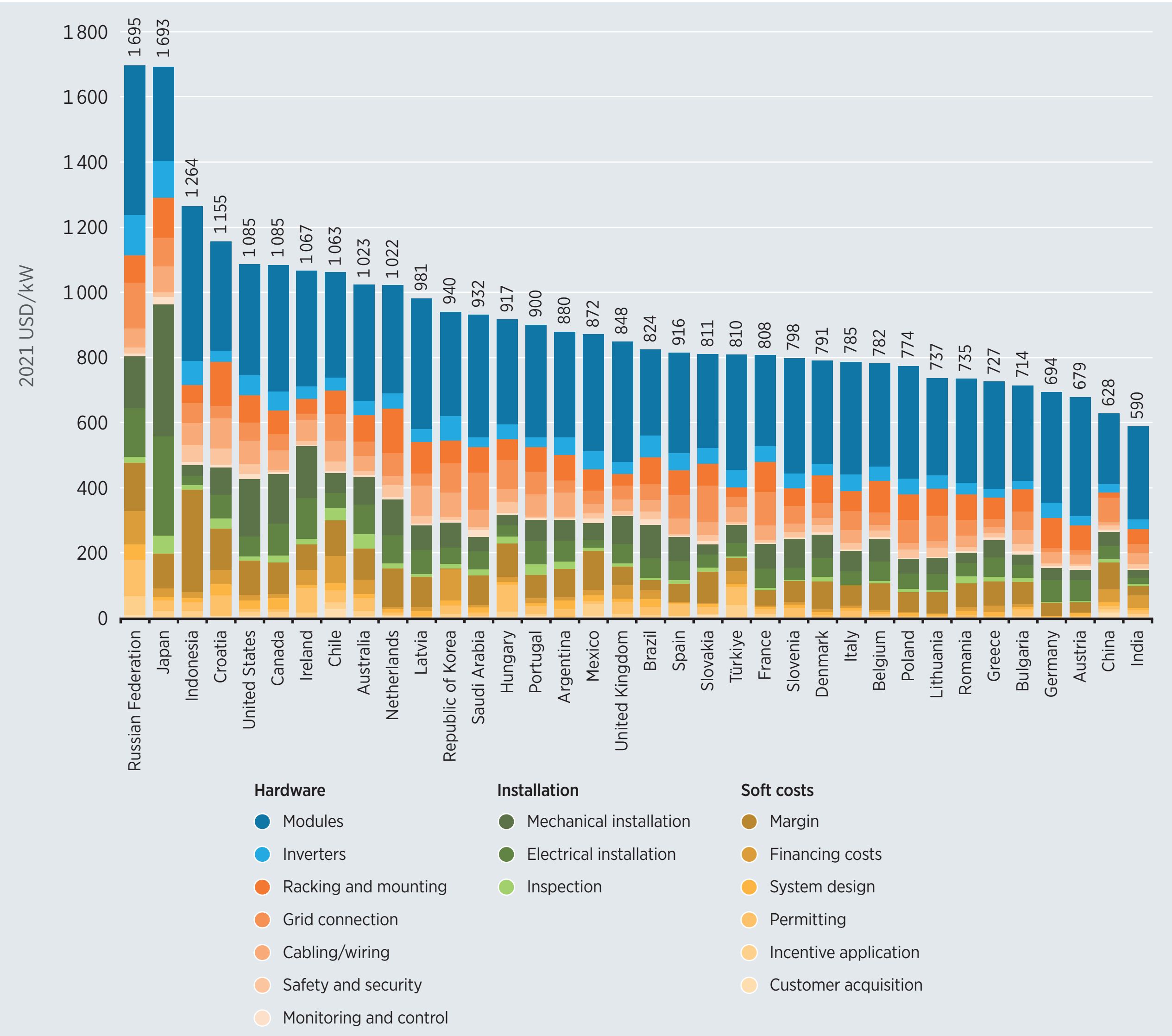
Meanwhile, after sustained market growth in recent years, PV deployment in Viet Nam plummeted, though total installed costs remained competitive, declining 30% in 2021 from the 2020 estimate. The PV market in Ukraine also declined between 2020 and 2021, while at the same time total installed costs there increased 17% year-on-year amid policy uncertainty (Figure 3.4).

Figure 3.4 Utility-scale solar PV total installed cost trends in selected countries, 2010-2021

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 2021. This means that BoS[49] costs are therefore also an important contributor to declining global weighted average total installed costs. Between 2010 and 2021, 14% 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, 2021



Source: IRENA Renewable Cost Database.

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

In 2021, 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 590/kW in India to a high of USD 1 695/kW in the Russian Federation. During 2019, the highest cost average was about 3.5 times more than the lowest, whereas in 2020 this ratio declined to about 3.2. This downward trend continued in 2021, reaching 2.9. This points to the recent convergence of installed costs in major markets.

During 2016, BoS costs (excluding inverters) made up about half of the total system cost. This value has tended to increase in recent years, highlighting the increasing importance of BoS costs, as module and inverter costs continued to fall. Between 2018 and 2020, the BoS share hovered between 62% and 64%, on average, in the markets assessed in Figure 3.5. Also on average, in 2021, BoS costs (excluding inverters) made up about 57% of total system costs in the countries in Figure 3.5. This lower value has been driven by increasing solar module costs. In 2021, total BoS costs ranged from a low of 42% in Austria to a high of 76% in the Russian Federation. Overall, soft cost categories for the countries evaluated made up 30% of total BoS costs and, on average, 17% of the total installed costs.

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 in order to be able to devise targeted policy changes that address outstanding issues properly – a detailed understanding of individual cost components remains essential, however.

CAPACITY FACTORS

By year commissioned, the global weighted average capacity factor[50] for new utility-scale solar PV increased from 13.8% in 2010 to 17.2% in 2021. Breaking this period down, between 2010 and 2018 the capacity factor showed an increasing trend, reaching its highest value so far, at 17.9%. This was predominantly driven by the increased share of deployment in sunnier locations. After that, the growth trend then reversed, but was followed by a recent uptick, which has likely been related to evolution in the technology, which has unlocked ways of harnessing more solar PV power from a given solar resource. In this regard, there has been a notable trend towards higher adoption of bifacial technology and increased use of trackers in utility-scale solar plants.

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

From 2018 to 2020, the 95th percentile value of the capacity factor declined significantly, from 27.0% to 20.8%, before increasing to 21.3% in 2021. The 5th percentile value declined less starkly, from 12.3% in 2018 to 9.9% in 2020, before growing to 10.8% in 2021 – a figure very close to its 2019 value. (Table 3.1).

Table 3.1 Global weighted average capacity factors for utility-scale PV systems by year of commissioning, 2010–2021

Year	5th percentile	Weighted average	95th percentile
2010	11.0%	13.8%	23.0%
2011	10.1%	15.3%	26.0%
2012	10.5%	15.1%	25.6%
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%
2021	10.8%	17.2%	21.3%

Source: IRENA Renewable Cost Database.

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

[50] 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.

The global weighted average capacity factor trend is a result of various concurring and often competing drivers. These include the increased use of tracking, project location, the solar resource and the increased market presence of bifacial modules, as well as the evolution of the inverter loading ratio (ILR).

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 in Bolinger *et al.,* 2021 that tracking made up 69% of the capacity installed in United States in 2015, up from 22% in 2010. During 2020, projects with trackers increased their dominance there by accounting for 90% of the United States' utility-scale market. At the same time, upfront cost premiums for trackers have been falling, resulting in favourable economics for projects with tracking devices in most of the United States, thanks to the increased generation they provide (Bolinger *et al.*, 2021).

The prevalence of trackers in other major utility markets and how this has developed with time, however, has not been sufficiently documented yet, restricting our ability to understand the impact of trackers on global capacity factor values.

A concurring trend towards higher ILRs is also complicating comparisons, in some cases. Depending on the context, increasing the DC array 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 each project. In the United States, both fixed-tilt and tracking projects recorded a median ILR of 1.34 in 2020. All things being equal, increasing ILR would result in a reduction in the AC/DC capacity factor.

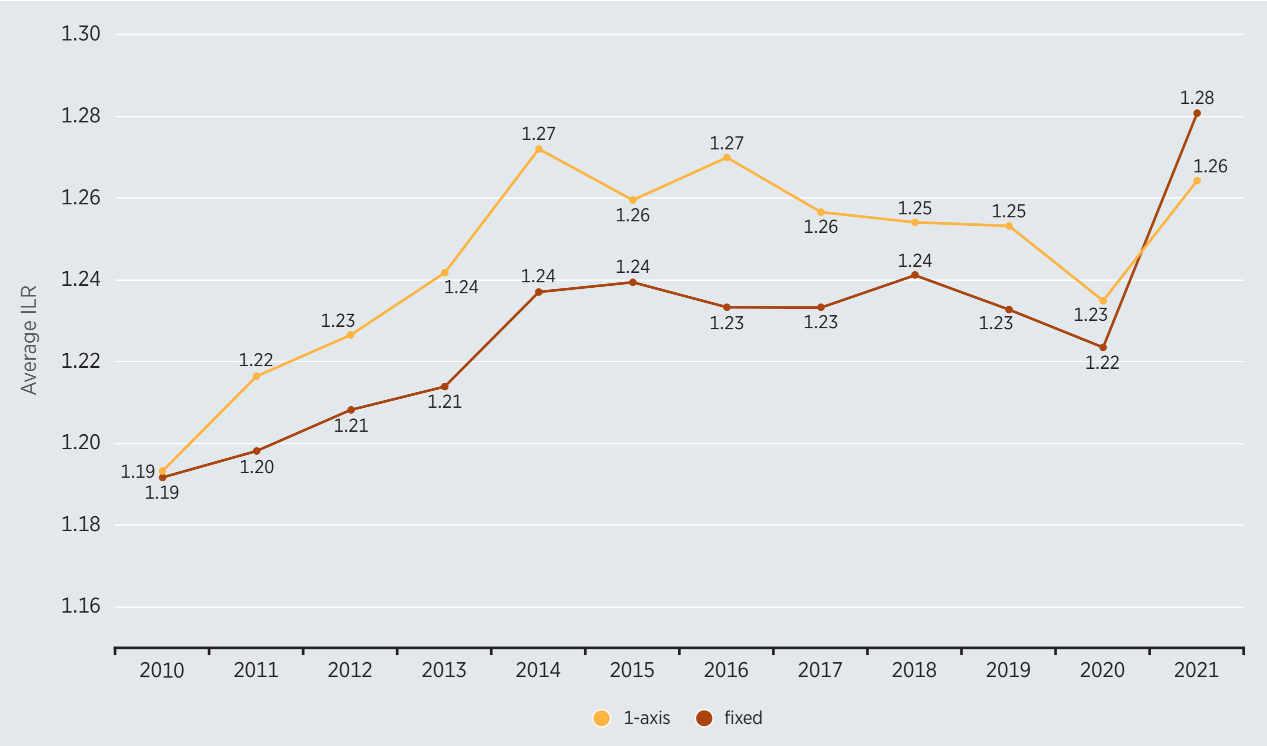
Globally, the combination of increased deployment in areas with favourable solar resource conditions and the increased use of tracking likely outweighed the effect of increasing ILR in the weighted average values for the capacity factor up until 2018. Since then, these factors appear to have been balancing out. Access to reliable ILR data is often challenging, however, although it remains necessary 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 2021.

This has resulted in a global subset of the IRENA Renewable Cost Database, for which ILR data is now available, comprising 209 GW of capacity from 7 066 projects. The subset's analysis shows similarities to the well-documented ILR trend in the United States.

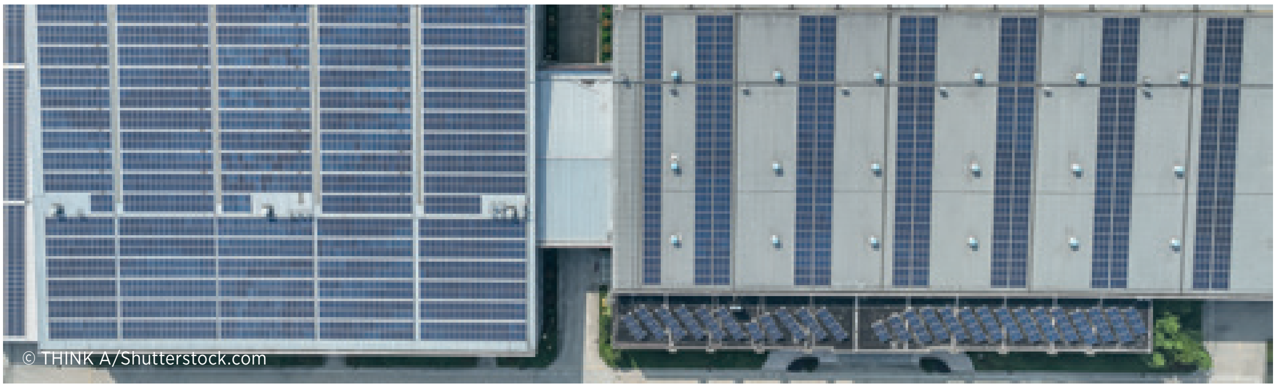
Indeed, as with the United States dataset, ILR values in this global dataset increased steadily from 2010 to 2013. The global dataset shows further ILR growth up until 2014.

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 fixed-tilt ILR then remained within the range 1.23 to 1.24 for all the years between 2016 and 2019, before falling to 1.22 in 2020. Preliminary data for 2021 shows it increasing to 1.28, its highest value since 2010. 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 they have consistently stayed above the level of fixed tilted systems. In 2020, the average ILR for a 1-axis tracked system was 1.23. Preliminary data for 2021 shows this value at 1.26 –below the fixed-tilt value for the first time, though still within 2% of it (Figure 3.6).

Figure 3.6 Global average inverter load ratio trend, 2010-2021



Source: BNEF, 2020c and IEA Wind, 2021.



Box 3.2 Battery storage cost trends in stationary applications

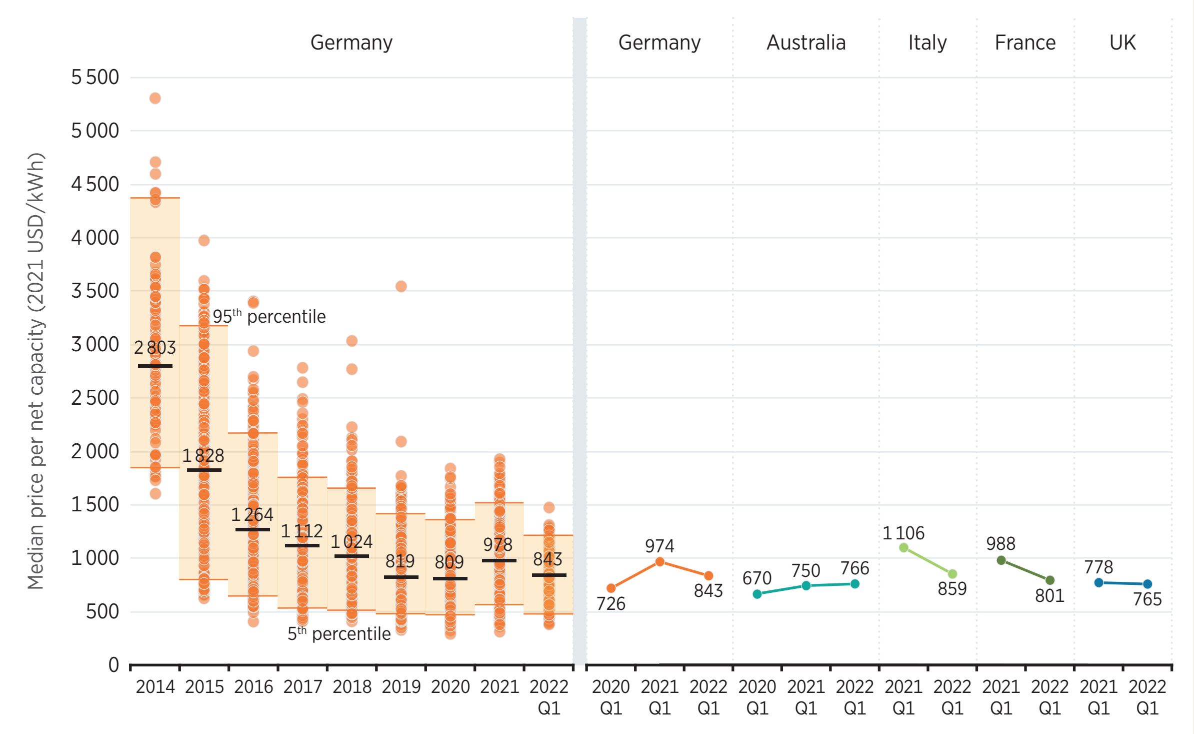
Electricity storage will play a crucial role in enabling the next phase of the energy transition. In particular, battery storage will play a prominent part in decarbonising transport and the electricity system (IRENA, 2021b). Battery storage costs are falling rapidly and as they do, the range of services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

Robust data for utility-scale battery cost reductions are not widely available. Yet, at the end of 2019, the United States had an installed, utility-scale battery capacity of 1 022 megawatts (MW), with 1 688 MW hours (MWh) of electricity storage capacity. Between 2015 and 2019, the cost of utility-scale battery storage in the United States fell by 72%, from USD 2 102/kWh to USD 589/kWh (EIA, 2021). This cost decline predominantly reflected the rate of decline in costs for lithium-ion batteries, given that they represented 93% of total installed battery energy capacity.

Meanwhile, small-scale, behind-the-meter battery storage systems, coupled with rooftop solar PV in residential and commercial buildings, has become a real growth market. Time series data for small-scale residential battery systems in Germany, for example, suggests that prices fell by 71% there between 2014 and 2020, with a price in 2020 of USD 809/kilowatt hour (kWh). During 2021, the price increased by a fifth, to USD 978/kWh. Preliminary Q1 2022 data sees prices returning to 2019/2020 values, though remaining still above these, at USD 843/kWh, which would represent a 70% decline on 2014 (Figure B3.2).

Data for Australia and the United Kingdom suggest prices somewhat lower than those experienced in Germany for small-scale residential battery storage systems. Battery storage systems in Italy and France are somewhat more expensive, which matches the experience in these countries with rooftop solar PV pricing. Between Q1 2021 and Q1 2022, however, prices in Italy and France declined 22% and 19% respectively. The price decline in Germany during that period was 13%, while UK costs have stayed relatively flat during this timeframe and are now at par with Australian pricing.

Figure B3.2 Behind-the-meter residential lithium-ion battery system prices in Germany, Australia, France, Italy and the United Kingdom, 2014 - Q1 2022



Source: IRENA and EUPD Research GmbH, 2022; and Solar Choice, 2022.

OPERATION AND MAINTENANCE COSTS

The operation and maintenance (O&M) costs of utility-scale solar PV plants have declined in the last decade, driven by module efficiency improvements, which have reduced the surface area required for every 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. In addition, improved 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 initiate preventative interventions ahead of failures.

In the United States, O&M costs declined 58% between 2011 and 2020, from USD 29/kW/year to USD 12/kW/year (Bolinger *et al.*, 2021). For the period 2018 to 2020, O&M cost estimates for utility-scale plants in the United States have been reported at between USD 10/kW/year and USD 19/kW/year (Wiser *et al.*, 2020; Bolinger *et al.*, 2019; Bolinger *et al.*, 2020; Bolinger *et al.*, 2021; EIA, 2020; NREL, 2018; Walker *et al.*, 2020).

Recent costs in the United States are dominated by preventive maintenance and module cleaning, with these making up 75% to 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.

Recently, average utility-scale O&M costs in Europe have been 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.

Utility-scale O&M costs in Europe have been reported at USD 10/kW per year... with historical data for Germany suggesting O&M costs fell by 85% between 2005 and 2017

For 2021, projects in the IRENA Renewable Cost Database had a capacity weighted average utility-scale O&M cost of USD 14.1/kW per year (a decline of 48% from 2010).[51] These are the estimated, total 'all-in' O&M costs, so include items such as insurance and asset management, which are sometimes not reported in all O&M surveys.

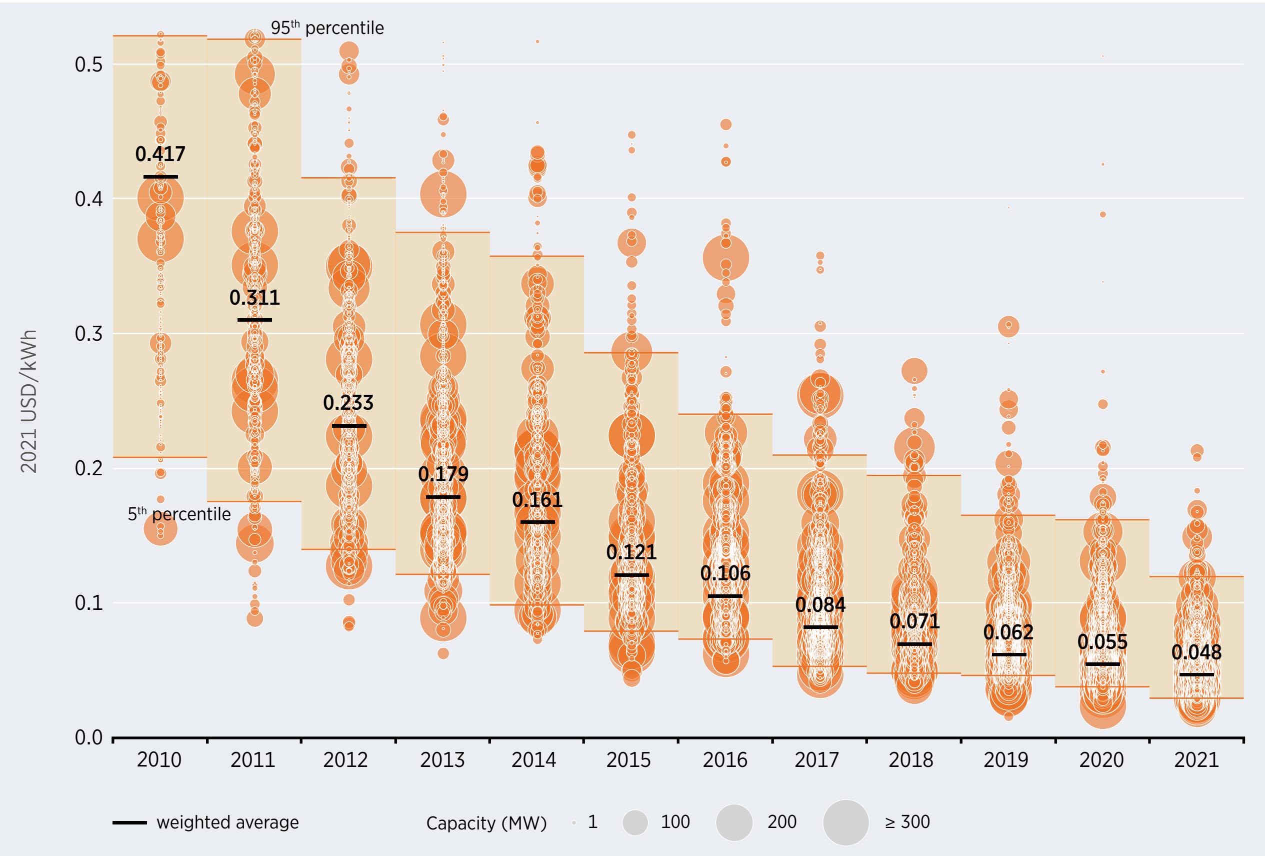
[51] *See Annex I for a more detail on O&M cost assumptions.*

LEVELISED COST OF ELECTRICITY

The global weighted average LCOE of utility-scale PV plants declined by 88% between 2010 and 2021, from USD 0.417/kWh to USD 0.048/kWh. This 2021 estimate also represents a 13% year-on-year decline from 2020.

Globally, too, the range of LCOE costs continues to narrow. In 2021, the 5th and 95th percentile of projects ranged from USD 0.029/kWh to USD 0.120/kWh, representing 86% and 77% declines on the 5th and 95th percentile values, respectively, in 2010. After remaining flat during 2018 and 2019, the 5th percentile value declined 17% between 2019 and 2020, to reach USD 0.038/kWh. Between 2020 and 2021, the decline was much starker, at 23%. In 2020, the 95th percentile value remained flat in relation to its value in 2019, but declined 26% between 2020 and 2021 (Figure 3.7).

Figure 3.7 Global utility-scale solar PV project LCOE and range, 2010-2021



Source: IRENA Renewable Cost Database.

The rapid decline in total installed costs, increasing capacity factors and falling O&M cost have contributed to a remarkable reduction in the cost of electricity from solar PV and its improving economic competitiveness (see Box 3.3).

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 75% and 90%, depending on the country.

Box 3.3 Unpacking the decline in utility-scale LCOE from 2010 to 2021

The remarkable, sustained and dramatic decline in the cost of electricity from utility-scale solar PV is one of the more compelling stories in the power generation sector's evolution over the past decade.

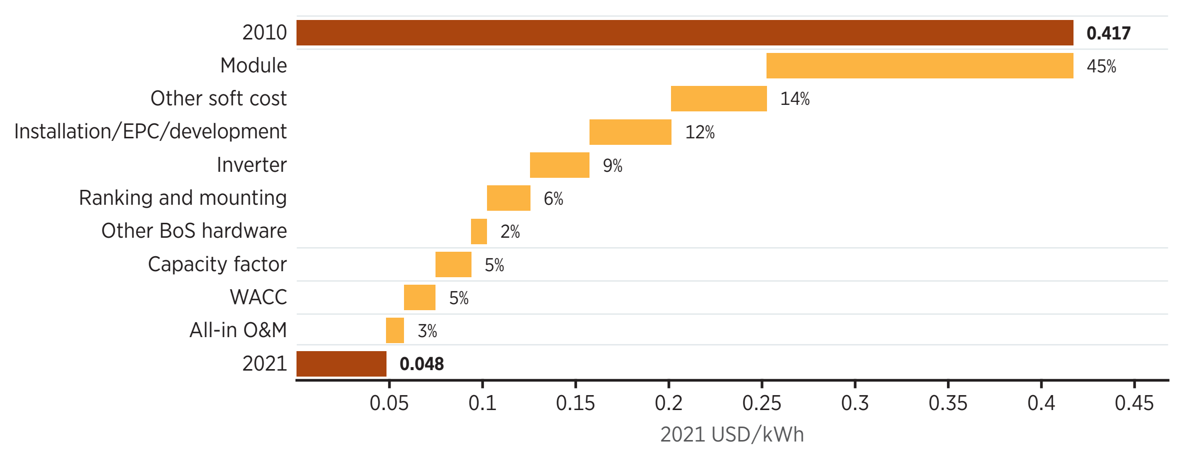
Since 2010, the solar PV industry has seen a variety of technological developments that have contributed to improvements in the competitiveness of the technology. These have occurred along the whole solar PV value chain. From the increased deployment of larger polysilicon factories and improved ingot 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 now that new solar PV markets have emerged, globally. Between 2010 and 2021, those cost declines contributed 45% to the LCOE reduction of utility-scale PV (Figure B3.3). The costs of other hardware components have also declined during the period. Indeed, taken together, cost reductions in inverters, racking and mounting, and other BoS hardware contributed another 17% to the LCOE reduction during the 2010 to 2021 period.

As solar PV technology has matured, the relevance of BoS costs has also increased. This is because module and inverter costs have historically decreased at a higher rate than non-module costs, increasing the share of total installed costs taken by BoS (IRENA, 2018). Engineering, procurement and construction (EPC), installation, and development costs, when combined with other soft costs, were responsible for 26% of the LCOE decline over the 2010 to 2021 period.

The rest of the reduction can be attributed to: improved financing conditions as markets have 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 B3.3 Drivers of the decline of LCOE of utility-scale solar PV (2010-2021)



Source: IRENA Renewable Cost Database.
Note: Percentage figures may not total 100 due to rounding up.

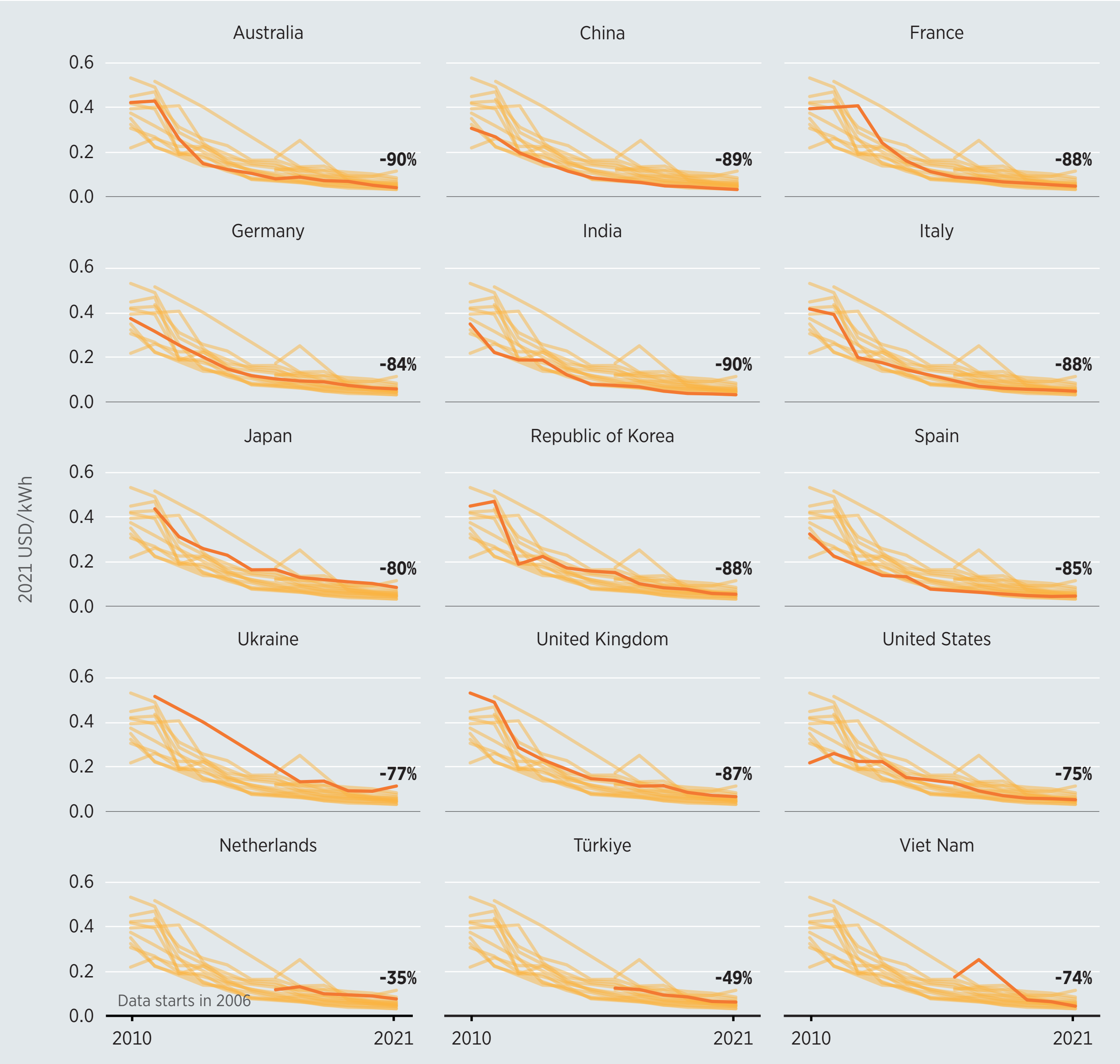
The lowest weighted average LCOE in the utility-scale sector could be observed in China, where between 2010 and 2021, costs declined by 89%, to reach USD 0.034/kWh – a value 29% lower than the global weighted average for that year, as reported in Figure 3.8.

After China, India achieved the most competitive LCOE in 2021, with a value of USD 0.035/kWh (just 2% above the value in China). Costs in Australia were the third most competitive amongst historical markets, at USD 0.042/kWh (24% above China), after a 21% year-on-year decline.

Beyond the historical markets, important LCOE reductions have also occurred. For example, the LCOE in Türkiye almost halved between 2016 and 2021, reaching a value of USD 0.064/kWh. The LCOE of projects in Viet Nam declined 30% – remaining competitive despite the very thin market in 2021 – with projects reaching USD 0.046/kWh that year. Spain reached a similarly competitive level, at USD 0.048/kWh, in spite of a 4% increase in the LCOE estimate between 2020 and 2021. This hike was because the market could not replicate the best cost values of 2020, even though its year-on-year deployment grew.

The LCOE of utility-scale PV in the USA declined 8% year-on-year, to reach USD 0.055/kWh during 2021 (14% above the global weighted average). During 2021, the LCOE value in Japan declined 17% compared to 2020, to reach USD 0.086/kWh. Despite this, the LCOE of utility-scale solar PV in Japan was around 2.5 times that of China (a ratio that remained almost unchanged from 2019). Driven by a total installed cost rise of 17%, the LCOE in Ukraine, at USD 1.117/kWh, was the highest amongst the markets illustrated in Figure 3.8.

Figure 3.8 Utility-scale solar PV weighted average cost of electricity in selected countries, 2010-2021



Source: IRENA Renewable Cost Database.

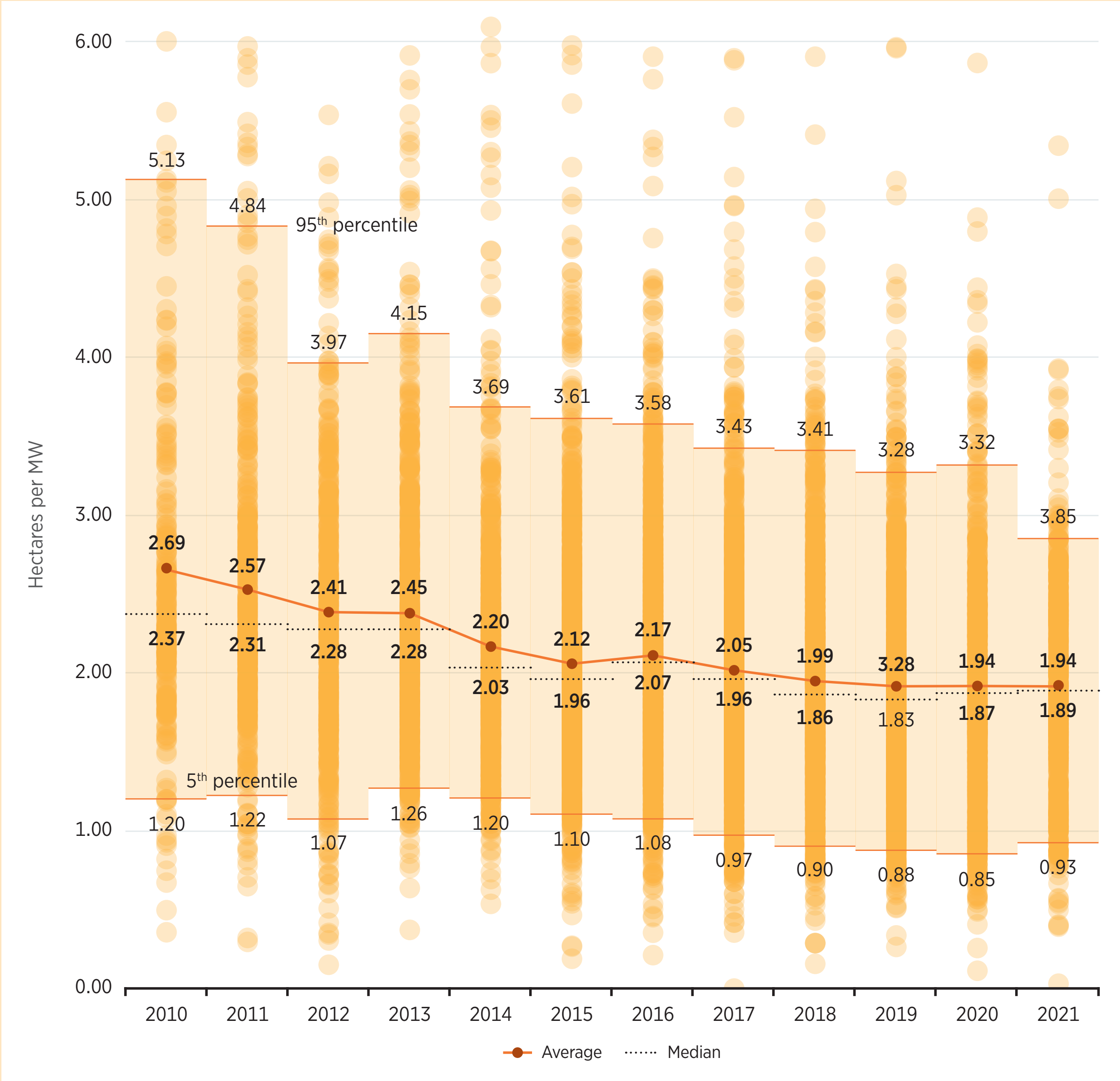
Box 3.4 Land use of utility-scale solar PV: Hectares per MW

As the efficiency of solar PV modules increases, they require less surface area to generate a given quantity of power. Consequently, while efficiency is an important driver of materials cost reductions, it also has an impact on land use.

Indeed, land availability issues are very significant in solar field array placement. When enough flexibility is available to create uniform arrays of square or rectangular shapes, less land area is required. As the shape of the land area becomes free-form, the land use efficiency declines somewhat, as some boundary curves or slopes may result in less efficient placement, from a land-use perspective. There is also an economic driver; where land is relatively cheap, there is less need to compromise on the optimisation of panel location for energy capture.

The impact of this can be seen in the wide range of values in hectares (ha)/MW shown in Figure B3.4 below, which also shows the module efficiency trend. The figure shows a decline of 62% between 2010 and 2021, from 2.69 ha/MW to 1.94 ha/MW, in the amount of land used by PV projects to generate each MW.

Figure B3.4 Global average utility-scale solar PV land use, 2010-2021



Source: IRENA Renewable Cost Database.

04 OFFSHORE WIND

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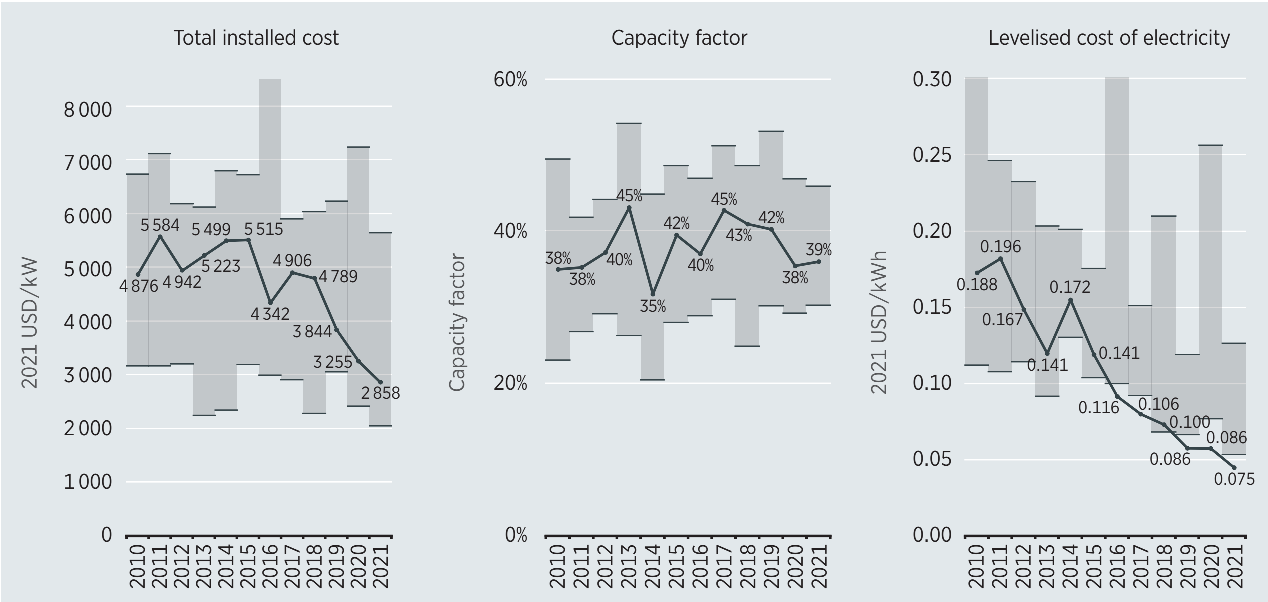
HIGHLIGHTS

- The global weighted average levelised cost of electricity (LCOE) of offshore wind declined by 60% between 2010 and 2021, from USD 0.188/kilowatt hour (kWh) to USD 0.075/kWh. In 2021 alone, there was an 13% reduction, year-on-year.
- In Europe, the weighted average LCOE of newly commissioned projects fell 29% between 2020 and 2021, from USD 0.092/kWh to USD 0.065/kWh. Driven by project economies of scale, there was a 25% reduction in total installed costs year-on-year and an increase in the weighted average capacity factor of new projects from 42% to 48% in 2021.
- Between 2010 and 2021, global weighted average total installed costs fell 41%, from USD 4 876/kilowatt (kW) to USD 2 858/kW. At its peak – in 2011 – the global weighted average total installed cost was USD 5 584/kW, twice its 2021 value.
- Global cumulative installed capacity of offshore wind increased more than eleven-fold between 2010 and 2021, from 3.1 gigawatts (GW) to 55.7 GW. This was driven almost equally by installations in China and Europe. In 2021, global cumulative installed capacity increased by over 60% as new capacity added of offshore wind was 21.3 GW, of which 17.4 GW was added in China and 2.9 GW in Europe.
- Improvements in technology – including larger turbines and longer blades with higher hub heights – along with access to better wind resources as wind farms moved further from 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 39% in 2021, as China increased its share of global deployment.
- Total installed cost and LCOE reductions have been driven by both technology improvements and the growing maturity of the industry. Indeed, growing developer experience, greater product standardisation, manufacturing industrialisation, regional manufacturing and service hubs, and economies of scale have all contributed to cost declines. These decreases have also been facilitated by clear policies on deployment and, in many cases, manufacturing, that have further supported growth.

Figure 4.1 Global weighted average and range of total installed costs, capacity factors and LCOE for offshore wind, 2010-2021



Source: IRENA Renewable Cost Database.

INTRODUCTION

Offshore wind technology has matured rapidly since 2010. Indeed, there was an eighteen-fold increase in cumulative deployed capacity between 2010 and 2021, from 3.1 GW to 55.7 GW (IRENA, 2022a).

Currently, however, offshore wind still only makes up under 7% of the total cumulative onshore and offshore global wind capacity. Yet, plans and targets for future deployment have been expanding, as costs have decreased and the technology has headed further towards maturity. For instance, Belgium, Denmark, Germany and the Netherlands announced in May this year a target of adding enough new capacity to reach a combined total of 150 GW of offshore wind by 2050.[52] Annual capacity additions averaged over 5 GW between 2017 and 2020, while in 2021, the added offshore wind capacity was 21.3 GW.

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 therefore more complex than that for onshore wind projects. Construction is even more complex again, increasing total installed costs still further. Given their offshore location, these projects also have higher grid connection costs.

As projects became sited farther from shore, in deeper waters, and used more advanced technology, offshore wind installed costs peaked around the period of 2011-2012.

With the recent increase in deployment, technology improvements, economies of scale, and increases in developer and turbine manufacturer experience, however, cost reductions have been unlocked.

The increasing maturity of the industry has also been 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. Indeed, installation times and costs per unit of capacity have been 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, as have the scale and optimisation benefits of servicing offshore wind farm zones, rather than individual wind farms. Increased wind turbine availability, as manufacturers are constantly learning from recent experience and incorporating improvements into newer products, has also helped lower costs.

An important area of improvement is also linked to the ongoing digitisation of the energy sector. The increasingly sophisticated use of the mass of information being generated from turbine performance data allows predictive maintenance programmes that are designed to intervene before costly failures occur – thereby contributing to lower O&M costs and improved availability.

[52] *See www.dr.dk/nyheder/viden/klima/danmark-spiller-afgoerende-rolle-i-storstilet-klimaplan-halvdelen-af-eus-havvind accessed 18 May 2022.*

Figure 4.2 presents the trend that occurred between 2000 and 2021 in Europe, compared with China and the rest of the world, in which offshore wind farms moved to deeper waters and farther from shore.

The offshore wind farms commissioned in Europe in 2000 averaged 25 megawatts (MW) in size and were located in a water depth of 7 metres (m), roughly 5 kilometres (km) from shore. These figures have significantly increased since then. In 2021, the average offshore windfarm size in Europe was 591 MW and it had a weighted average water depth of 39 m and a distance to shore of 23 km. In China, the average offshore windfarm size was 245 MW, with a weighted average water depth of 31 m and a distance to shore of 12 km, according to project data in the IRENA Renewable Cost Database.

Table 4.1 below shows the characteristics of an average offshore wind farm in China and Europe between 2010 and 2021. The trend to deeper waters and further from shore is most pronounced in Europe – the most mature market for offshore wind. Most recent projects in Europe have been in waters between 30 m and 50 m deep, with an increasing proportion located between 50 km and 120 km out – although many European projects do also remain closer to shore.

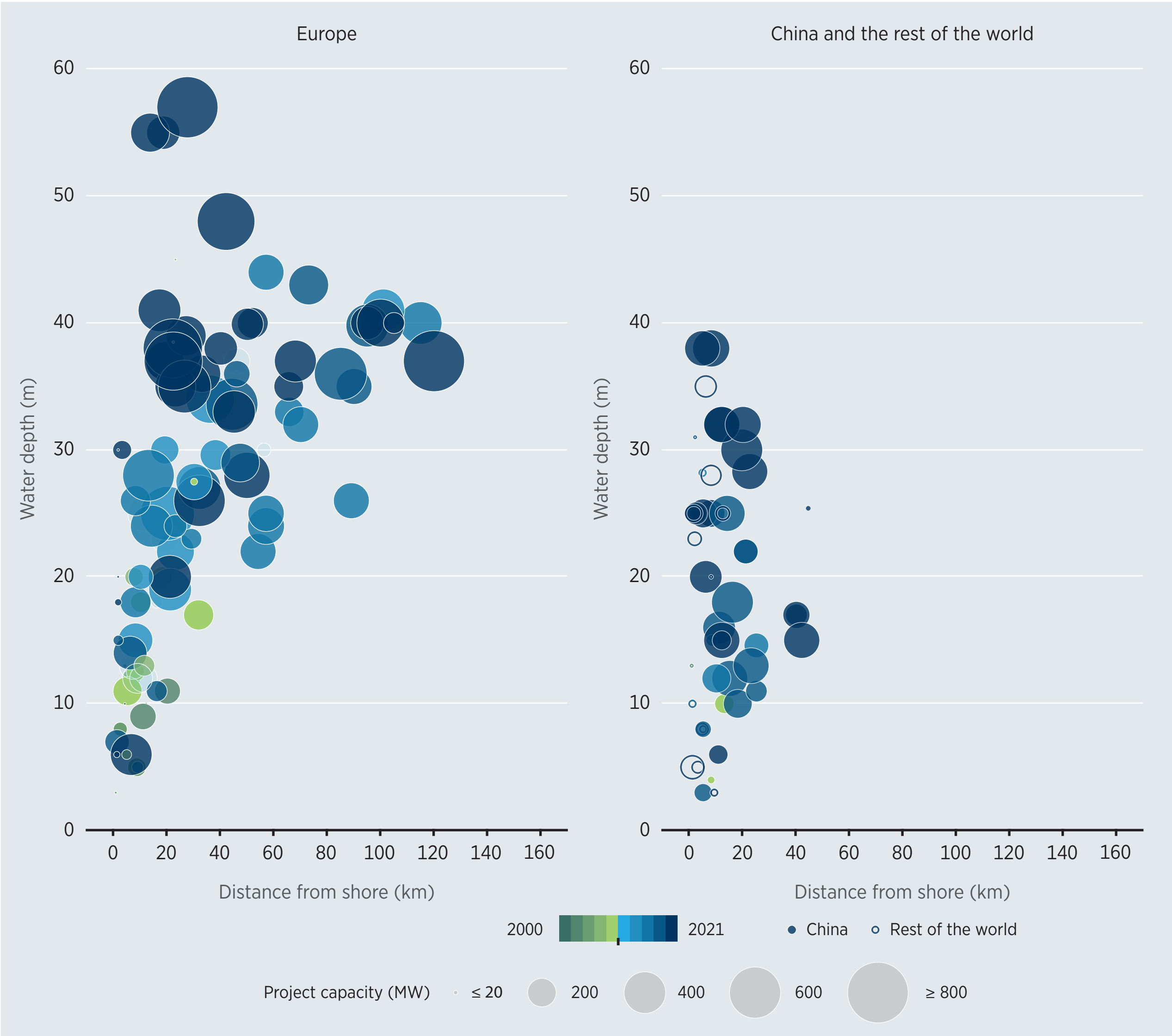
The majority of the more distant projects can be found in Germany and the United Kingdom. The latter is Europe's largest offshore wind proponent, with 12.7 GW of installed capacity at the end of 2021. Belgium, China, Denmark and the Netherlands are still largely exploiting zones closer to shore, although the Netherlands also has a significant share of its total wind farms 50 km or more from the coast. All of these countries are, however, currently still able to exploit areas in shallow water, from 20 m to 40 m deep (Figure 4.3).

With relatively few commissioned offshore wind farms outside the major markets of Europe and China, however, there is no real global trend in water depth and distance from shore. Most countries continue to prioritise zones close to shore (less than 15 km from the coast), albeit with a very wide spread of water depths (26 m to 50 m for utility-scale projects).

Along with the water depth, the distance from a shore or port that is able to support installation has an impact on total installed costs, as the latter impacts the number of return trips to port for foundations and turbines during installation, while the latter impacts 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, which make installation more difficult, and this has added time and cost to the already high logistical costs when projects are farther from ports (EEA, 2009). This impact has stabilised, however, even for the large wind farms that are now the norm in European waters. Installation costs have also been coming down with larger turbines, while the IRENA Renewable Cost Database shows installation times – from first foundation to commissioning – declining since 2015 to between 1.4 and 2.4 years for wind farms for which data are available.

Figure 4.2 Average distance from shore and water depth for offshore wind in China, Europe and the rest of the world, 2000-2021



Source: IRENA Renewable Cost Database.

Figure 4.3 Distance from shore and water depth for offshore wind by country, 2000-2025

Source: IRENA Renewable Cost Database.

Table 4.1 Project characteristics in China and Europe in 2010, 2015 and 2021

The average offshore wind farm in China vs Europe		2010	2015	2020	2021
Project size (MW)	China	67	109	350	245
	Europe	155	270	347	591
Distance from shore (km)	China	12	10	21	12
	Europe	18	49	41	23
Water depth (m)	China	9	12	29	31
	Europe	21	29	39	39
Hub height (m)	China	-	90	103	102
	Europe	83	87	97	108
Rotor diameter (m)	China	-	130	162	163
	Europe	112	119	162	159
Turbine size (MW)	China	2.8	4.0	5.9	6.7
	Europe	3.1	4.2	7.9	8.5

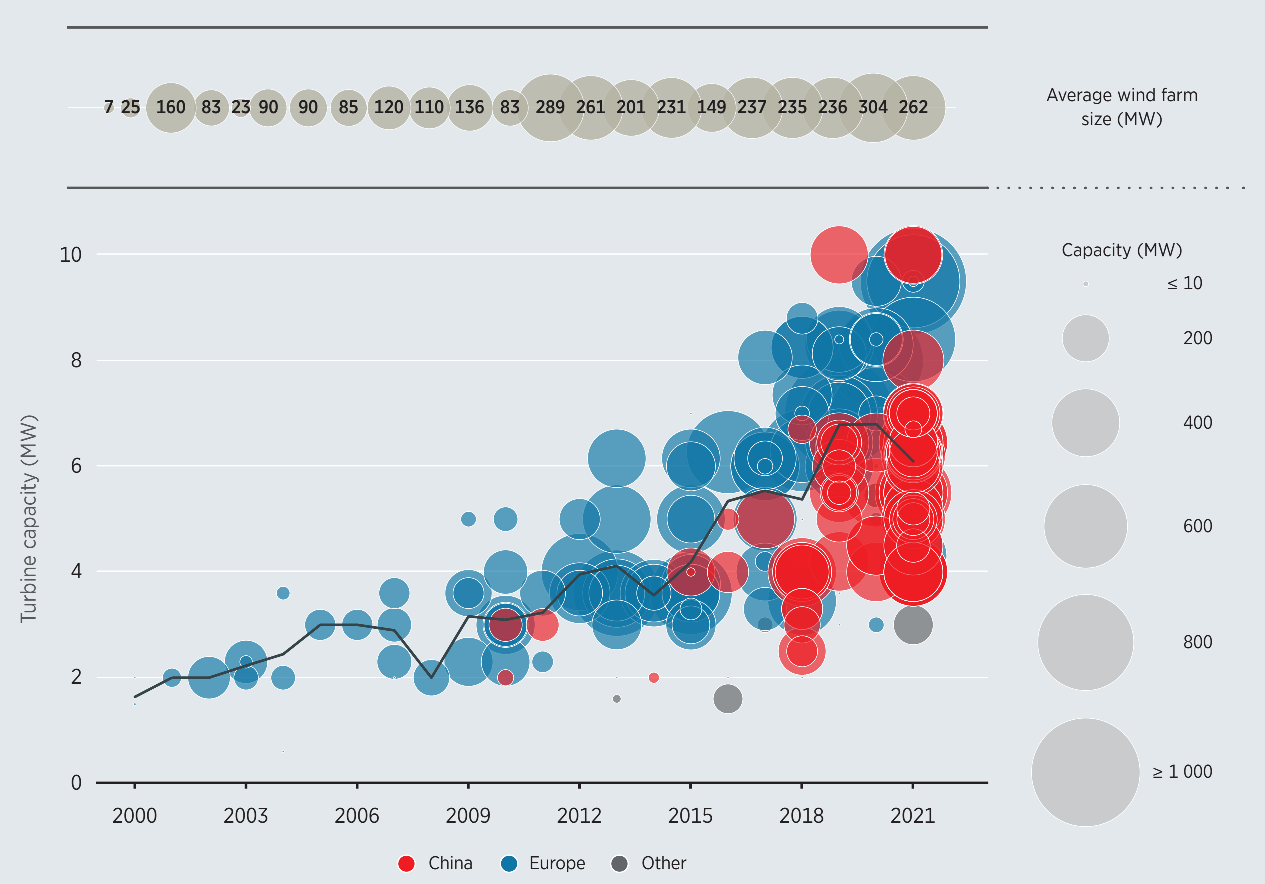
Source: IRENA Renewable Cost Database.

In addition to offshore wind farms 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 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 4.4).

Figure 4.5 shows that in China, Germany and Belgium – countries where projects tend to use larger rotor diameters – the weighted average rotor diameter increased by 40% between 2010 and 2021. In 2021, Germany had a weighted average rotor diameter of 162 m, while in China it was 161 m. The weighted average rotor diameter for Europe was 112 m in 2010, rising 46% to 163 m in 2021.

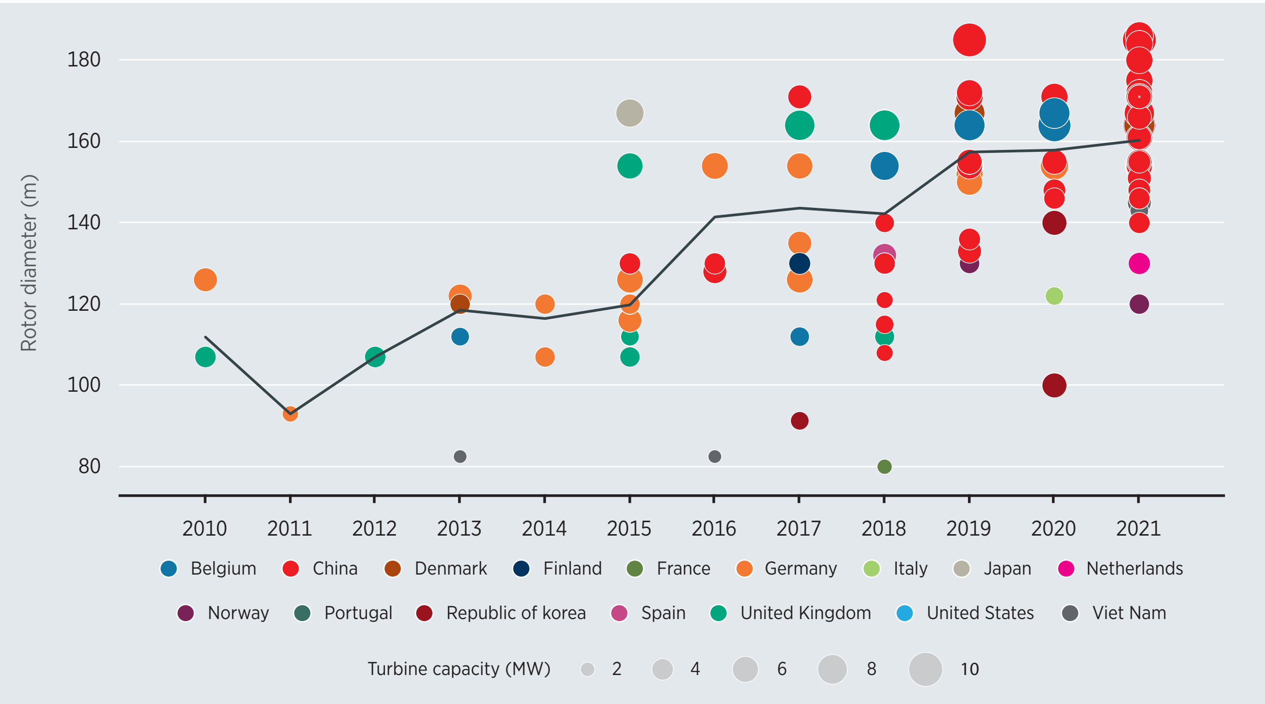
There has been a trend towards higher capacity turbines designed for the offshore sector, increasing energy capture and reducing the LCOE of projects

Figure 4.4 Project turbine size, global weighted average turbine size and wind farm capacity for offshore wind, 2000-2021



Source: IRENA Renewable Cost Database.

Figure 4.5 Project and weighted average turbine rotor diameter for offshore wind by country, 2010-2021



Source: IRENA Renewable Cost Database.

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 obtaining permits and environmental consents is 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.

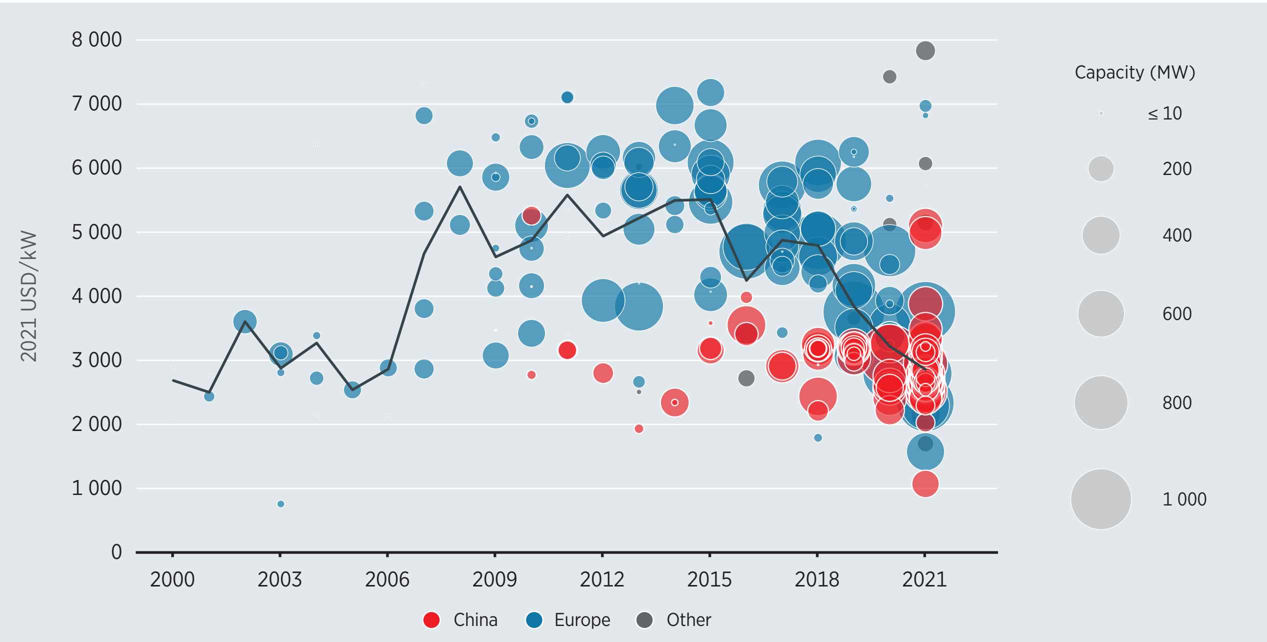
Offshore wind, however, has the advantage of economies of scale, meaning that some of these costs are not disproportionately higher than those for onshore wind.

At the same time, higher capacity factors are available offshore, with the more stable wind output (due to higher average wind speeds and reduced wind shear and turbulence) coinciding with winter demand peaks in Europe. This ensures offshore wind output is of higher value to the electricity system than onshore wind.

The promise of offshore wind has therefore always been evident and, in the last few years, it has started to realise its potential through scaling. Between 2010 and 2020, the average offshore wind project size increased by 124%, from 136 MW to 304 MW. In 2021, the global average offshore wind project size was 262 MW. Since 2020, there have been projects that have capacities exceeding 1 GW.

The global weighted average total installed cost of offshore wind farms increased from around USD 2 685/kW in 2000 to over USD 5 712/kW in 2008. It then bounced around the USD 5 250/kW mark for the period 2008 to 2015, as projects moved farther from shore and into deeper waters (Figure 4.6). The global weighted average total installed cost then began to decline after 2015, falling relatively rapidly to USD 2 858/kW in 2021.

Figure 4.6 Project and weighted average total installed costs for offshore wind, 2000-2021



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 49% from their peak in 2011 to a global weighted average of USD 2 858/kW for projects commissioned in 2021.

Major support for this trend 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 annual global weighted average total installed cost remains volatile.

That yearly volatility is also 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, too, adding to the drive annual volatility. In 2021, for example, China dominated total deployment. The global weighted average total installed costs were 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.[53]

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

It is therefore important to look at total installed cost trends on a country-by-country basis in order to understand how cost structures are evolving.

Between 2010 and 2020, Belgium had the highest percentage decrease (44%) in weighted average total installed cost – from USD 6 334/kW to USD 3 545/kW. Over a similar period, 2010-2021, China, which has the largest cumulative wind deployment globally (roughly 9 GW), experienced a 38% decline in weighted average total installed cost, from USD 4 638/kW to USD 2 857/kW (Table 4.2).

In China, grid connection assets are developed and owned by public entities, or the transmission network owner, lowering the project-specific installed costs. Denmark has a similar system and as a result, its project-specific weighted average total installed costs in 2021 were USD 2 289/kW.

In the United Kingdom, which had the second largest offshore wind added capacity in 2021 (2.3 GW), the project-specific weighted average total installed cost was USD 3 057/kW. That year, all the regions and countries listed in Table 4.2 experienced a decrease in weighted average total installed costs.

Offshore and onshore wind farms have differing cost breakdowns. This is to be expected, given offshore wind farms' higher average costs for installation and foundations. Data availability for project-level total installed costs is, however, almost non-existent due to confidentiality issues. Yet, numerous studies do 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 4.7). Other costs, however – including installation, foundations 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 between 10% and 14%, electrical interconnection between 8% and 24% and foundation costs between 14% and 22%. Development costs, which include planning, project management and other administrative costs, comprise 2% to 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).

Between 2010 and 2021, China experienced a 38% decline in weighted average total installed cost - from USD 4 638/kW to USD 2 857/kW

Table 4.2 Regional and country weighted average total installed costs and ranges for offshore wind, 2010 and 2021

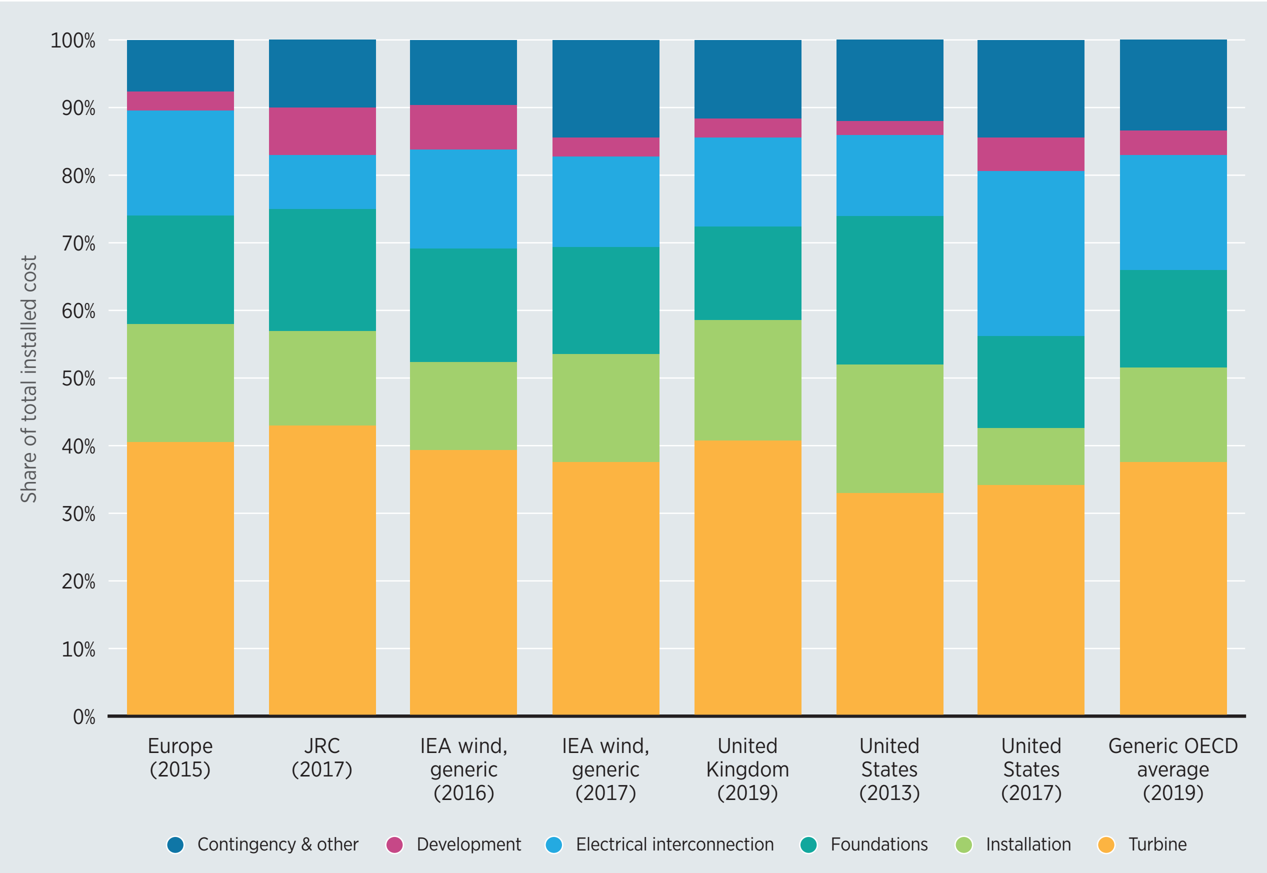
	2010			2021		
	5th percentile	Weighted average	95th percentile	5th percentile	Weighted average	95th percentile
	(2021 USD/kW)					
Asia	2 981	**4 680**	5 240	1 859	**2 876**	6 917
China	2 912	**4 638**	5 152	2 406	**2 857**	3 474
Japan	5 113	**5 113**	5 113	5 201	**5 550**	6 030
Republic of Korea*	n.a.	**n.a.**	n.a.	5 238	**6 278**	7 317
Europe	3 683	**4 883**	6 739	1 859	**2 775**	6 917
Belgium*	6 334	**6 334**	6 334	3 371	**3 545**	3 876
Denmark	3 422	**3 422**	3 422	2 289	**2 289**	2 289
Germany*	6 739	**6 739**	6 739	3 603	**3 739**	4 452
Netherlands**	4 299	**4 299**	4 299	1 695	**2 449**	6 424
United Kingdom	4 225	**4 753**	5 072	2 363	**3 057**	6 495

Source: IRENA Renewable Cost Database.

** Countries where data were only available for projects commissioned in 2020, not 2021.*

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

Figure 4.7 Representative offshore wind farm total installed cost breakdowns by country/region, 2013, 2016, 2017 and 2019



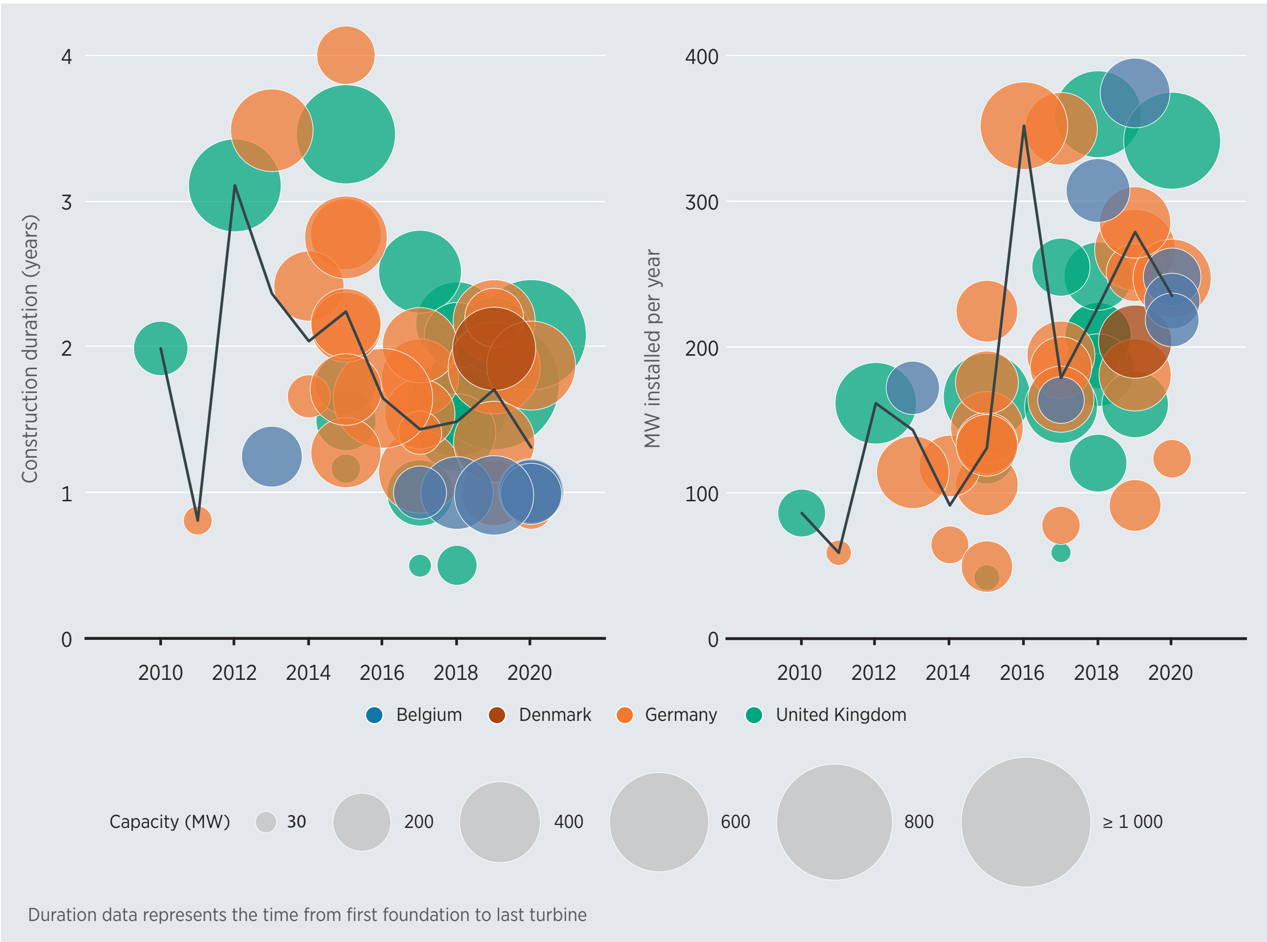
Source: IRENA Renewable Cost Database.

As detailed in Figure 4.7, installation costs for turbines are a major contributor to the total cost. This reflects the expense of transporting, operating and installing foundations and turbines offshore, with distance to port another major contributing cost factor.

As larger, dedicated installation vessels have become available, however, experience has been gathered and larger turbines have been employed. As a result, installation times for projects have fallen. From an average of two or more years per wind farm between 2010 and 2015, by 2020, the installation time had fallen to less than 18 months.

To capture the dynamics mentioned above, however – and given varying project sizes – a better metric than installation time is MW installed per year by project. In the latter terms, a much stronger trend can be seen in the data available for Europe since 2018. In these data, the figures increase from 100 MW to 200 MW during 2010 to 2015 to between 200 MW and 300 MW per year per project from 2015 to 2020. From 2016, projects also routinely exceeded 300 MW per year (Figure 4.8).

Figure 4.8 Installation time per offshore wind project in Europe, 2010-2020



Source: IRENA Renewable Cost Database.

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 wind farm's configuration, *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 2021, the global weighted average capacity factor of newly commissioned offshore wind farms grew from 38% to 39%. In 2021, the capacity factor range (5^{th} and 95^{th} percentile) for newly installed projects was between 30% and 46% (Figure 4.9). 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 (around 82% of new capacity added in 2021). As discussed, China's projects tend to be near-shore or inter-tidal – locations which generally have poorer wind resources than those available 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 48% in 2021. In Europe, the 5^{th} and 95^{th} percentile capacity factors for projects commissioned in 2021 were 41% and 52% respectively. In contrast, the weighted average capacity factor for projects commissioned in China in 2021 was 37%, while the 5^{th} and 95^{th} percentiles were 31% and 40%, respectively.

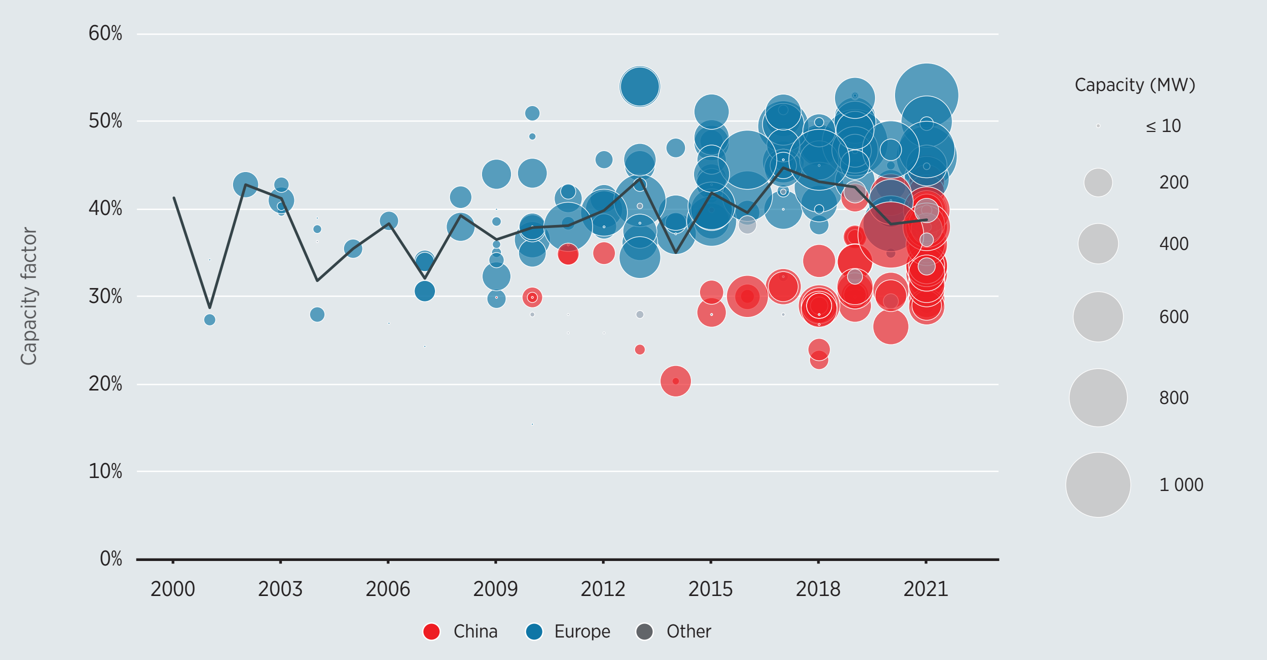
Capacity factors have been rising due to the installation of larger wind turbines with higher hub-heights and larger swept areas than previously available, enabling turbines to harvest more electricity from the same resource. Figure 4.10 shows that both offshore wind rotor diameter and hub height followed a similar, increasing trend over the period 2010 to 2021. The turbine rotor diameter experienced a 43% increase over that period, growing from a weighted average value of 112 m to 160 m. Over the same period, turbine hub height grew by 27%, from a weighted average of 83 m to 105 m.

With rotor diameters increasing faster than both hub heights and turbine sizes, the specific power of wind turbines (measured in watts per square metre [W/m^2]) has fallen over time, particularly in Europe. This has important implications for capacity factor trends, as, all else being equal, in many situations, lower specific power levels will result in higher capacity factors.

There has also been a trend towards 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.

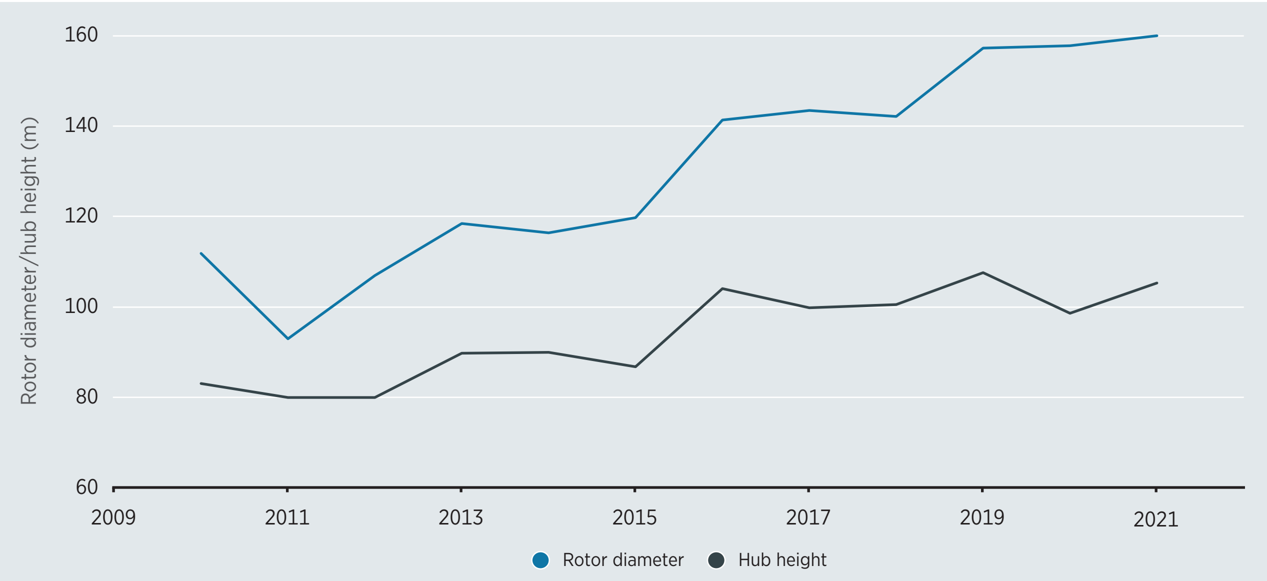
For the period 2010 to 2021, an examination of weighted average capacity factor improvements in countries with offshore wind installations shows that the greatest improvement was in the United Kingdom, where there was a 33% increase over the period (Table 4.3). Germany was the exception to generally increasing capacity factors over the period. This can be attributed to the already relatively high capacity factor achieved in 2010, significantly above the country's 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). Similar trends can be also seen in the Netherlands.

Figure 4.9 Project and weighted average capacity factors for offshore wind, 2000-2021



Source: IRENA Renewable Cost Database.

Figure 4.10 Weighted average offshore wind turbine rotor diameter and hub height 2010-2021



Source: IRENA Renewable Cost Database.

Table 4.3 Weighted average capacity factors for offshore wind projects in six countries, 2010 and 2021

	2010	2021	Percentage change 2010-2020
	%		
Belgium*	38	41*	↑ 8%
China	30	37	↑ 23%
Denmark	44	50	↑ 14%
Germany*	46	42*	↓ 9%
Japan	28	30	↑ 7%
Netherlands**	48**	46	↓ 4%
United Kingdom	36	48	↑ 33%

Source: IRENA Renewable Cost Database.

** Countries where data were only available for projects commissioned in 2020, not 2021.*

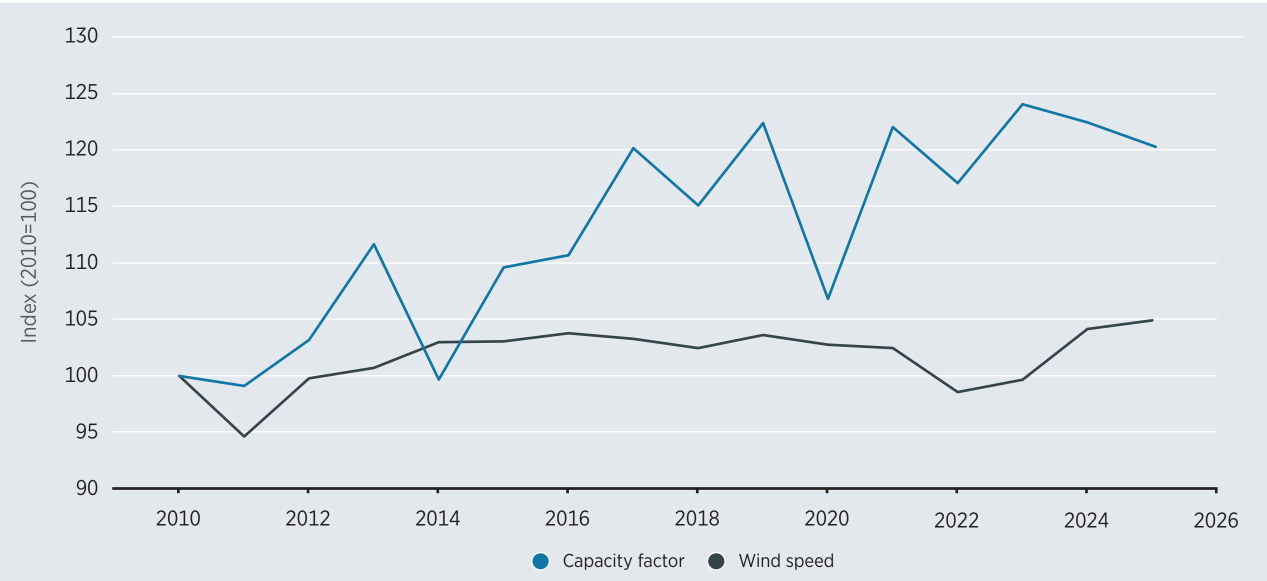
*** The Netherlands had no projects commissioned in 2010, so data for projects commissioned in 2015 are shown.*

The data for Europe shows the clear contribution technology improvements have made in boosting the capacity factors of offshore wind farms over the last decade, with this likely to continue for the next few years.

Between 2010 and 2020, the weighted average capacity factor of newly commissioned projects increased by around 8%, while the weighted average wind resource for those projects increased by only 2%. The year 2020 was something of an outlier for wind projects in Europe, however. Looking at 2019 and 2021, the numbers were +22% and +4%, and +13% and +3%, respectively, relative to projects in 2010.

In addition to the improvements in offshore wind turbines that have already been mentioned – including higher hub heights and larger swept areas – increased capacity factors have come from improved wind farm layouts, the increased durability of components and the benefits of big data in developing preventative maintenance programmes to reduce unplanned outages in periods of high wind output (Figure 4.11).

Figure 4.11 Capacity factor and wind speed trends by project in Europe, 2010-2025

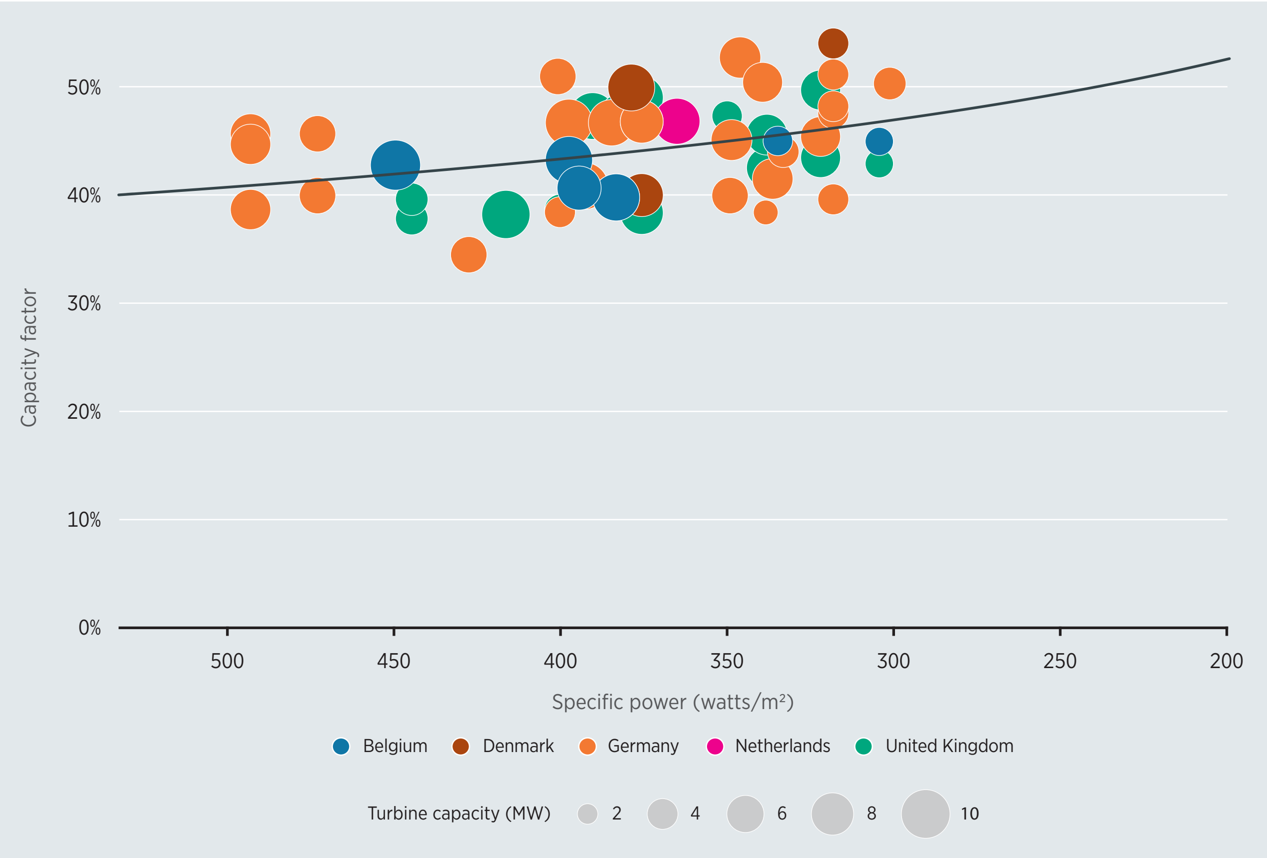


Source: IRENA Renewable Cost Database.

Figure 4.12 shows the relationship between specific power (mapped inversely) and capacity factors for offshore wind projects for which IRENA has data. All else being equal, larger rotor blades will harness more energy from the wind, turning the rotor blades at higher rates than shorter blades. This means turbine generators operate at higher output levels and at maximum-rated capacities for longer periods. The combined impact of this will be a higher capacity factor.

The data available suggests that, over time, this increase has happened in Europe. There is a statistically significant relationship – albeit one that does not explain a lot of the variation seen in the chart (*e.g.* a low coefficient of determination, or R^2) – suggesting other factors are also in play. The impact of hub heights and wind resource qualities across the countries represented in the chart are likely having a significant impact, although a full statistical analysis would be required to identify the main drivers.

Figure 4.12 Offshore wind capacity factors and specific power



Source: IRENA Renewable Cost Database.

Larger rotor blades harness more energy from the wind, allowing turbine generators to operate at higher output levels and at maximum-rated capacities for longer periods

OPERATION AND MAINTENANCE COSTS

O&M costs for offshore wind farms per kW are higher than those for onshore wind. This is mainly due to the higher cost of accessing the wind site to perform maintenance on turbines and cabling. The latter is heavily influenced by weather conditions and the availability of skilled personnel and specialised vessels. Given the higher capacity factors offshore, however, O&M costs are also amortised over a larger output, meaning offshore wind O&M costs typically constitute 16% to 25% of the LCOE for offshore wind farms deployed in the Group of 20 (G20) 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, however. As a result of improved capacity factors, and due to increased competition in O&M provision, O&M costs per kilowatt-hour (kWh) have therefore been falling.

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' own 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. Ørsted was able to reduce O&M costs by over 43% between 2015 and 2018, from USD 118/kW/year to USD 67/kW/year (Ørsted, 2019).

Based on projects commissioned over the last 5 years, IRENA analysis shows that O&M costs account for between USD 0.017/kWh and USD 0.030/kWh,[54] 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 set up, *e.g.* Republic of Korea (which also has lower weighted average capacity factors).

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

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 increasingly competitive projects.

Between 2010 and 2021, the global weighted average LCOE of offshore wind fell 60%, from USD 0.188/kWh to USD 0.075/kWh (Figure 4.13). The latter, 2021 figure was 13% down on its 2020 value of USD 0.086/kWh. From its peak in 2007, the global weighted average LCOE of offshore wind had fallen 65% by 2021.

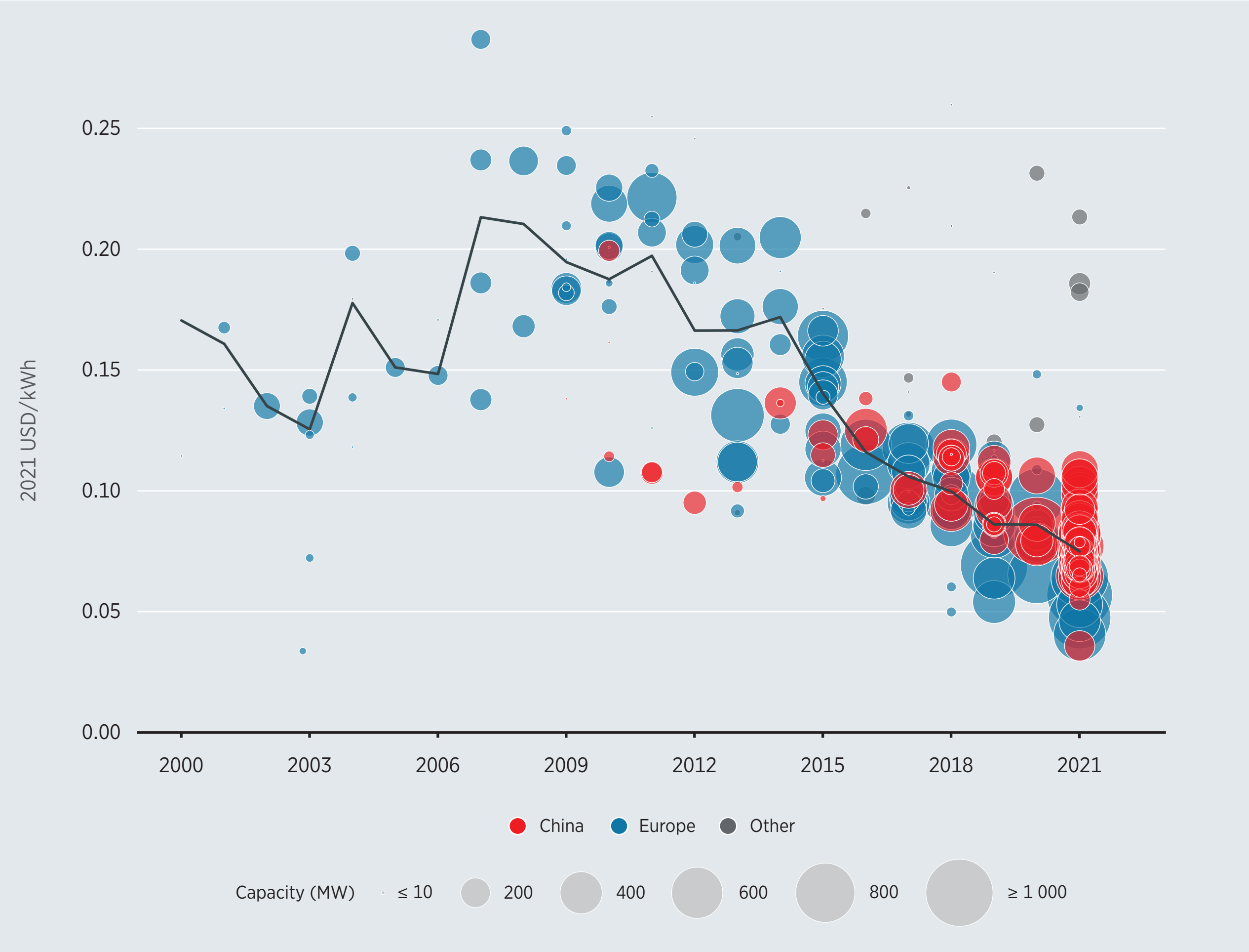
Denmark had the lowest weighted average LCOE for projects commissioned in 2021, at USD 0.041/kWh (Table 4.4). The United Kingdom had the second-lowest weighted average LCOE, at USD 0.054. It also had the highest percentage reduction in country weighted average LCOE values between 2010 and 2021, at 74%. Denmark was second-highest in this percentage reduction (62%) over the same period.

Denmark was also 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 therefore partly driven by experience, as well as by 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.

Elsewhere, Belgium had a reduction of 63% in weighted average LCOE between 2010 and 2020 (the country had no added offshore wind capacity in 2021). Belgium also had the highest starting point for weighted average LCOE in 2010, at USD 0.226/kWh.

As Figure 4.13 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.

Figure 4.13 Offshore wind project and global weighted average LCOEs and auction/PPA prices, 2000-2024



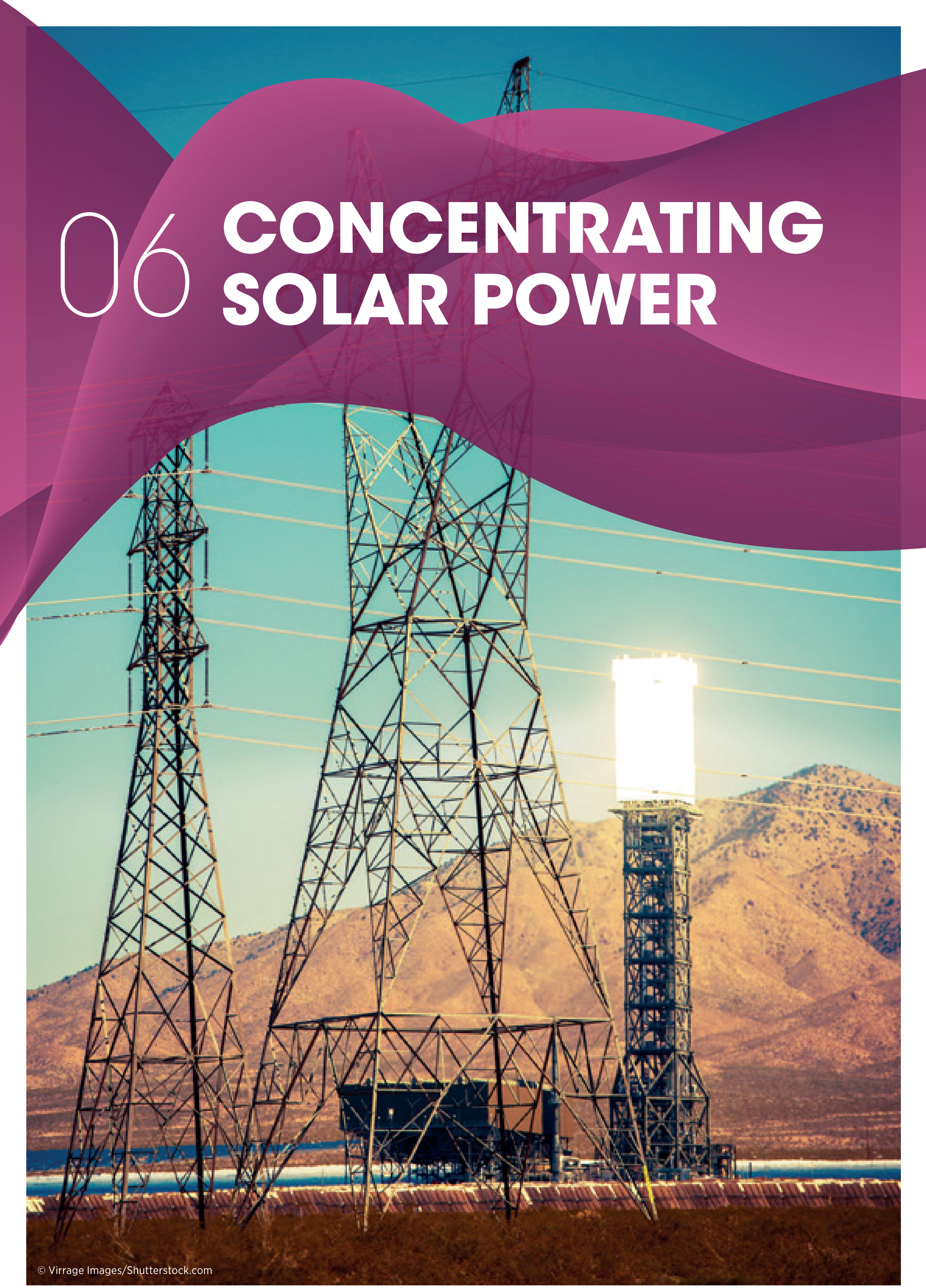
Source: IRENA Renewable Cost Database.

Table 4.4 Regional and country weighted average LCOE of offshore wind, 2010 and 2021

	2010			2021		
	5th percentile	Weighted average	95th percentile	5th percentile	Weighted average	95th percentile
	(2021 USD/kW)					
Asia	0.127	**0.187**	0.219	0.069	**0.083**	0.112
China	0.119	**0.178**	0.196	0.064	**0.079**	0.103
Japan	0.187	**0.187**	0.187	0.184	**0.196**	0.212
Republic of Korea*	n.a.	**n.a.**	n.a.	0.133*	**0.180***	0.227*
Europe	0.127	**0.163**	0.297	0.051	**0.065**	0.140
Belgium*	0.226	**0.226**	0.226	0.082*	**0.083***	0.086*
Denmark	0.108	**0.108**	0.108	0.041	**0.041**	0.041
Germany*	0.177	**0.179**	0.186	0.080*	**0.081***	0.083*
Netherlands	n.a.	**n.a.**	n.a.	0.048	**0.059**	0.128
United Kingdom	0.201	**0.210**	0.217	0.049	**0.054**	0.092

Source: IRENA Renewable Cost Database.
** Countries where data were only available for projects commissioned in 2020, not 2021.*

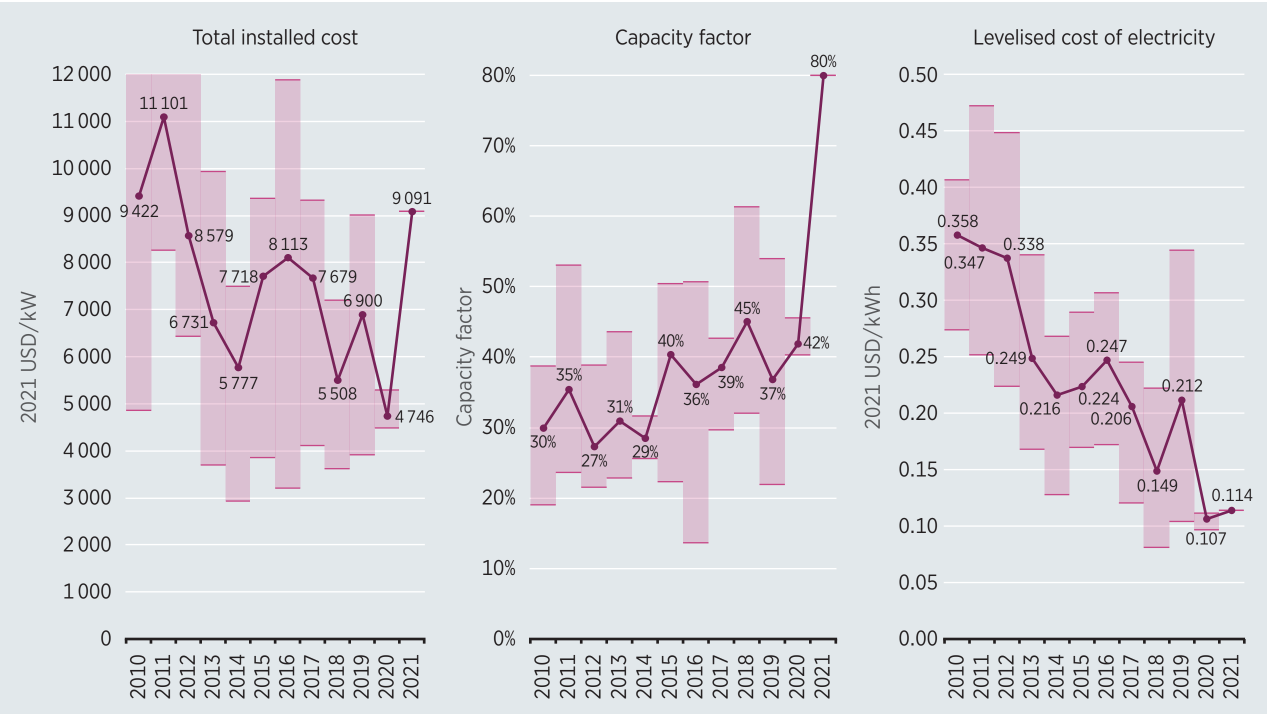
06 CONCENTRATING SOLAR POWER



HIGHLIGHTS

- Between 2010 and 2021, the global weighted average levelised cost of electricity (LCOE) of concentrating solar power (CSP) plants fell by 68%, from USD 0.358/kilowatt hour (kWh) to USD 0.114/kWh.
- Between 2010 and 2020, the global weighted average LCOE had declined by 70%, to USD 0.107/kWh. This was primarily driven by reductions in total installed costs (down 64%), higher capacity factors (up 17%), lower operations and maintenance (O&M) costs (down 10%) and a reduction in the weighted average cost of capital (down 9%).
- Between 2010 and 2020, CSP's global average total installed costs declined by half, to USD 4 746/kilowatt (kW). This was achieved in a setting where project energy storage capacities were increasing continuously.
- During 2021, however, these total installed costs increased to USD 9 090/kW – just 4% lower than in 2010. Yet, this value should be interpreted with care, as there was only one project worldwide that came online in 2021. Located in the Atacama Desert in Chile, the Cerro Dominador project boasts 17.5 hours of storage. This is the highest ever recorded storage capacity for a CSP project and is in part responsible for the high total installed costs of the project (though also the reason for its competitive LCOE).
- The global weighted average capacity factor of newly-commissioned 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 excellent solar resource in the location of the Cerro Dominador CSP project, meant a very high capacity factor value for 2021, at 80%.

Figure 5.1 Global weighted average total installed costs, capacity factors and LCOE for CSP, 2010-2021



Source: IRENA Renewable Cost Database.

INTRODUCTION

CSP systems work in areas with high (typically above 2 000 kW/m²/year) direct normal irradiance (DNI) by using mirrors to concentrate the sun's rays to create heat. In most systems today, the heat created this way is transferred to a heat transfer medium – typically a thermal oil or molten salt. Electricity is then generated through a thermodynamic cycle – for example, by using the heat transfer fluid to create steam and then generate electricity, as in conventional Rankine-cycle thermal power plants.

Today, CSP plants almost exclusively include low-cost and long-duration thermal storage systems to. This gives CSP greater flexibility in dispatch and the ability to target output in high cost periods of the electricity market. Indeed, this is also usually the route to lowest-cost and highest value electricity because thermal energy storage is now a cost-effective way to raise CSP capacity factors. 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. Such systems are either 'line concentrating' or 'point concentrating', with these terms referring to the arrangement of the concentrating mirrors.

Today, most CSP projects use line concentrating systems called parabolic trough collectors (PTCs). Typically, single PTCs consist of a holding structure with an 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 an absorber), which is a thermally efficient component placed in the collector's focal line. Many PTCs are traditionally connected in 'loops' through which the heat transfer medium circulates and which help 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 known as 'power towers', are the most widely deployed point focus CSP technology, although such systems represented only around a fifth of total CSP deployment at the end of 2020 (SolarPACES, 2021). In ST systems, thousands of heliostats are arranged in a circular or semi-circular pattern around a large central receiver tower to redirect the sun rays towards it. 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 ST designs do away with the heat transfer medium, however, and steam is directly generated at the receiver.

STs can achieve very high solar concentration factors (above 1 000 suns) and therefore operate at higher temperatures than PTCs. This can give ST systems an advantage, as higher operating temperatures result in greater steam-cycle and power block efficiencies. Higher receiver temperatures also unlock higher power 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 gigawatts (GW) by the end of that period. Breaking the last five years of this down, after modest activity in 2016 and 2017 – with annual additions hovering around 100 megawatts (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. In 2020, only 150 MW was commissioned globally, with all of this this coming online in China. Hopes for growth in 2021 did not materialise, though 110 MW (all from the Cerro Dominador project) was commissioned during that year in Chile. At the same time, about 265 MW from the Solar Energy Generating Systems (SEGS) plant in the USA – in operation since the late 1980s – was retired. This puts the cumulative global installed capacity of CSP at the end of 2021 at around 6.4 GW.

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. Developers have struggled and some projects have been lagging, while others have found new developers and some projects appear unlikely to be completed.

The outlook for 2022/2023 is somewhat brighter, however, with the possibility that close to 1.4 GW of new capacity could be commissioned in China and the United Arab Emirates. Spain has launched an auction that includes 200 MW of CSP capacity, but the results are yet to be announced. The CSP project pipeline includes a 100 MW solar tower project with 12 hours of storage expected to come online by 2024 in South Africa. Botswana's Ministry of Mineral Resources, Green Technology and Energy Security has initiated a pre-qualification process for participation in a 200 MW CSP tender, while Namibia has announced plans to launch a CSP tender in 2022 for between 50 MW and 130 MW of CSP capacity. In addition to this, a 300 MW project is planned to come online in 2025 in Qinghai, China.

National Energy and Climate Plans (NECPs) of some EU Member States show and indication of the potential development of the CSP project pipeline in the future. For example, Spain plans to add 5 GW and Italy 880 MW of new CSP capacity by 2030.

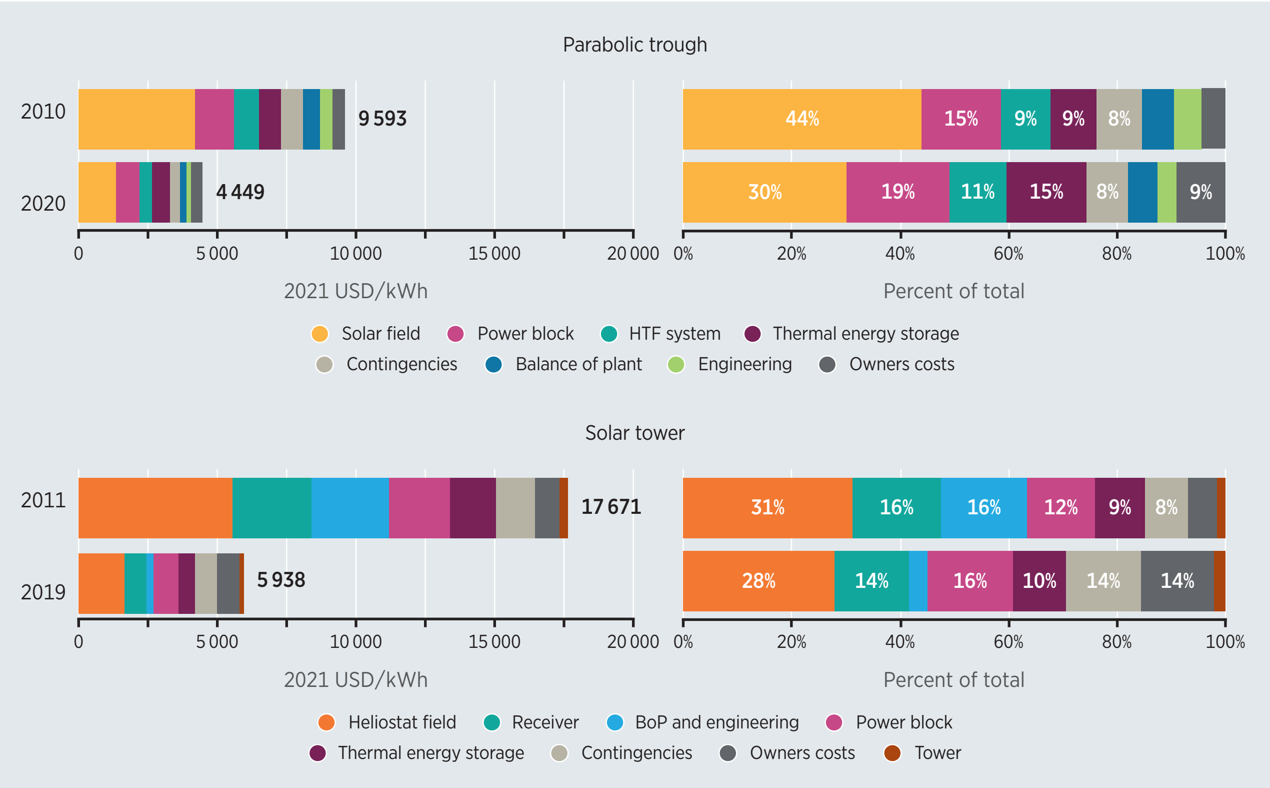
TOTAL INSTALLED COSTS

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. 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 6.1 hours between 2015 and 2019 (an 84% increase). For STs, that value increased from 5 hours in the 2010 to 2014 period to 7.7 hours in the 2015 to 2019 period (a 53% increase). In 2020, the 150 MW of newly-commissioned capacity in China had a weighted average storage capacity of 11 hours. Commissioned in 2021, the Cerro Dominador 110 MW ST project, located in Chile's Atacama Desert, features a storage capacity of 17.5 hours. It is likely that all new CSP projects developed worldwide will include thermal storage.

Total installed costs for both PTC and ST plants are dominated by the cost of the components that make up the solar field. Although data on the total installed cost breakdown for 2010 relies on bottom-up, techno-economic analyses (Hinkley, 2010; Fichtner, 2011), the data can be paired with IRENA's project level installed cost to get an understanding of the total installed cost breakdown in 2010/11 and 2019/20 (Figure 5.2).

Figure 5.2 Total installed cost breakdown of CSP plants by technology (2010/2011 and 2019/2020)



Source: IRENA Renewable Cost Database; Hinkley, 2010 and Fichtner, 2011.
Note: HTF = heat transfer fluid; BoP = balance of plant.

In 2010, the solar field of a PTC plant cost an estimated USD 4 209/kW (44% of the total installed cost), but by 2020, this figure had fallen 68% to USD 1 345/kW (30% of the total). With such a dramatic reduction in costs for the solar field, other cost areas with smaller declines saw their share of total installed costs increase. The power block's share, for example, increased from 15% in 2010 to 19% in 2020, despite its cost falling by 40% over the period, from USD 1 401/kW to USD 834/kW. This was also the case for the heat transfer fluid system, which increased its share from 9% to 11%, despite these costs per kW falling 47% over the period, from USD 886/kW to USD 470/kW. This also occurred for thermal energy storage. That component's share of total installed costs increased from 9% in 2010 to 15% in 2020, despite the cost itself falling from USD 815/kW to USD 660/kW. At the same time, during that period, the owner's costs share rose from 5% to 9%, while it also rose in value, from USD 399/kW to USD 434/kW.

Over the 2010 to 2020 period, the costs of the balance of plant, engineering, and contingencies for PTC plants declined by 60%, 64% and 57% respectively. As a result, the share of balance of plant in total installed costs declined from USD 585/kW (6% of the total) to USD 236/kW (5%) over the same period, while engineering costs fell from USD 473/kW (5% of the total) to USD 168/kW (4%). A measure of how far the weighted average total installed costs for PTC plants have fallen is the fact that the costs of the solar field alone in 2010 were only 5% lower than the weighted average total installed cost in 2020.

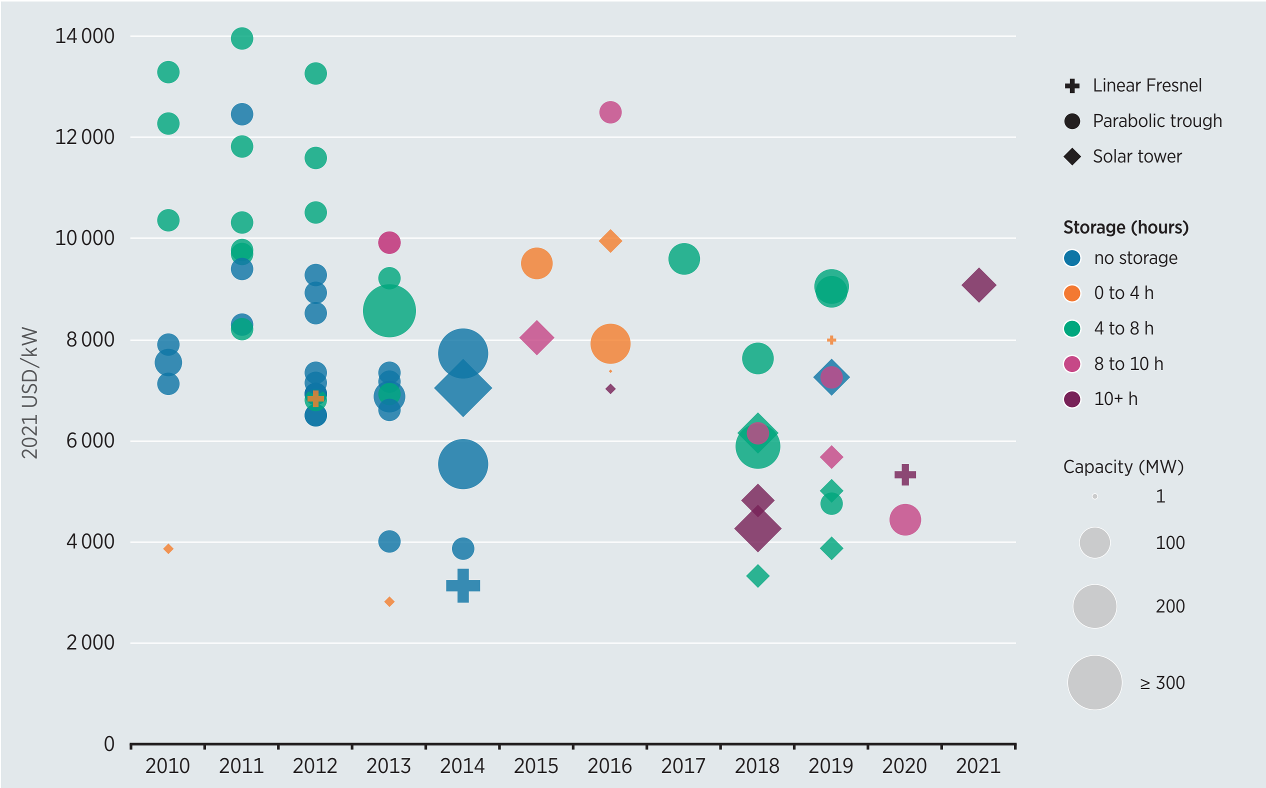
For ST plants, this comparison is very similar, with 2010 costs being only 7% lower than the ST weighted average total installed cost value in 2020. Over that decade, the reduction in the cost of the heliostat field was significant, with costs falling 70% between 2011 and 2019, from USD 5 528/kW to USD 1 652/kW. This drove down the field's share of total installed costs from 31% to 28%.

The cost of the receiver fell by 71% over the 2011 to 2019 period, from USD 2 868/kW to USD 819/kW, with the receiver's share of total costs falling from 16% to 14%. Balance of plant and engineering saw the largest reduction, however, falling 93% over the same period, from USD 2 804/kW to USD 205/kW. This made this factor's share of total costs fall from 16% to just 3%.

Contingencies remain an important overall cost component for STs, despite their share falling by 42% between 2011 and 2019, from USD 1 420/kW to USD 820/kW. At 14% of overall costs, in absolute terms, contingencies were still 1.8 times higher for STs than for PTC plants, per kilowatt. This likely reflects the fact that experience with STs remains relatively limited, with the replicability of their development and construction processes still holding greater uncertainty than for PTC plants. The latter have a longer commercial track record and a significantly larger number of installed projects. This may also be why owner's costs have fallen by only 12% over the period, with their share of overall costs increasing to 14% in 2019.

Between 2010 and 2020, the weighted average total installed cost value for CSP plants in IRENA's Renewable Cost Database fell by one half (50%) to reach USD 4 746/kW (Figure 5.3).

Figure 5.3 CSP total installed costs by project size, collector type and amount of storage, 2010-2021



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.

Figure 5.3 also shows that total installed costs increased in 2021, to USD 9 090/kW. This trend should be interpreted with care, however, as the 2021 value corresponds to that of the first solar power plant developed in Latin America, which was inaugurated in June that year. Taking that value into account, the total installed cost decline between 2010 and 2021 was 4%. This was despite the fact that the LCOE decline for that period stayed at a similar level to that recorded between 2010 and 2021, given the high capacity factor of the Chilean Cerro Dominador project, which boasts 17.5 hours of storage.

Data from the IRENA Renewable Cost Database shows that total installed costs for CSP plants declined during the last decade, even as the size of these projects' thermal energy storage systems increased.

Total installed costs for CSP plants fell by 50% between 2010 and 2020. This occurred even as the size of these projects' thermal energy storage systems 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 to 2014 period – sometimes dramatically so. The projects commissioned in 2018 and 2019 and listed in the IRENA Renewable Cost Database had an average of 7 hours of storage. This is 2.1 times more than the average storage value for projects commissioned between 2010 and 2014. Storage continued to grow after that, too. For instance, the weighted average storage level for projects commissioned in 2020 and 2021 was 13.8 hours, which was 70% higher than the level in 2018 and 2019.

The capital costs for CSP projects commissioned in 2020 for which cost data is available in the IRENA Renewable Cost Database ranged between USD 4 449/kW and USD 5 339/kW. With only two projects completed in China in 2020, totalling 150 MW, the data reflect national circumstances, much as the years 2010 to 2012 saw Spain dominate CSP deployment.

The two projects completed in China were part of a programme 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 into the electricity system. The programme, launched in 2016 and aiming to develop 1.35 GW of capacity, initially targeted completion by 2018, but undoubtedly this timeline was too ambitious. With weighted average total installed costs of USD 4 746/kW in 2020, costs were 31% lower than the weighted average of USD 6 900/kW for projects commissioned in 2019.

During 2018 and 2019, IRENA's Renewable Cost Database shows a capital cost range of between USD 3 337/kW and USD 9 064/kW for CSP projects with storage capacities of between four and eight hours. In the same period, the cost range for projects with eight hours or more of thermal storage capacity was narrower – between USD 4 275/kW and USD 7 265/kW. This range also had a lower maximum value. This was due to the fact that the majority of these projects were in China. Between 2018 and 2020, three projects in China were commissioned with greater than 10 hours of storage, with a total installed cost range from USD 4 275/kW to USD 5 339/kW.

CAPACITY FACTORS

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 distinctive in that the potential to incorporate low-cost thermal energy storage can increase the capacity factor[55] 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 of grid operators or shareholders in capturing the highest wholesale price.

This optimisation of a CSP plant's design also requires detailed simulations, which are often aided by techno-economic optimisation software tools that rely increasingly on advanced algorithms. These simulations must consider 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

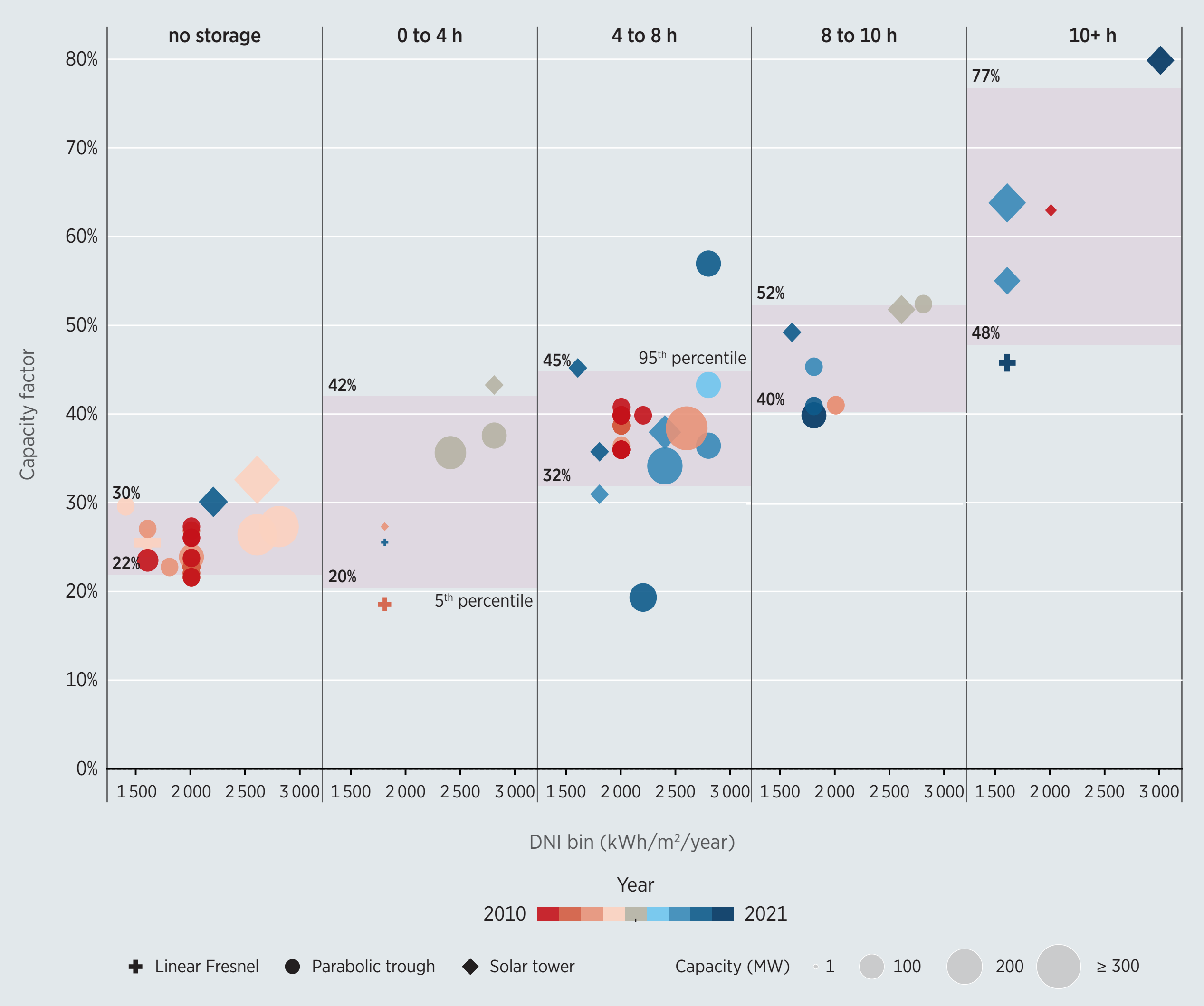
Over the last decade, falling costs for thermal energy storage and increased operating temperatures have been important developments in improving the economics of CSP. Increased operating temperatures also lower the cost of storage, as higher heat transfer fluid (HTF) temperatures lower storage costs. 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 5th and 95th 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 excellent solar resource in Chile's Atacama Desert, the location of the Cerro Dominador CSP project, meant a very high capacity factor value for 2021, at 80%.

[55] *Up to a certain level, given that there are diminishing marginal returns.*

The increasing capacity factors for CSP plants driven by increased storage capacity can clearly be seen in Figure 5.4. Over time, CSP projects have been commissioned with longer storage durations.

Figure 5.4 Capacity factor trends for CSP plants by direct normal irradiance and storage duration, 2010-2021



Source: IRENA Renewable Cost Database and CSP Guru, 2021, for DNI values.

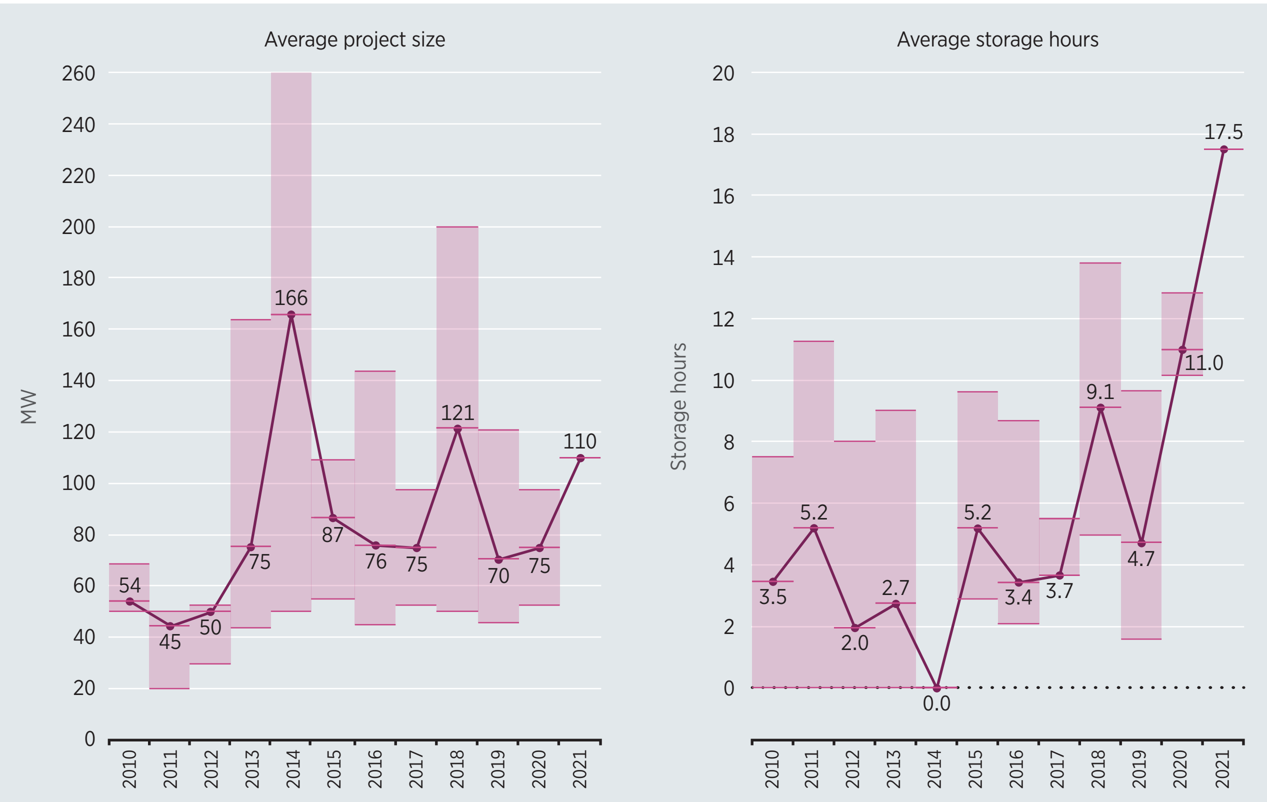
For plants commissioned from 2016 to 2020, inclusive, around four-fifths had at least four hours of storage and 35% had eight hours or more. The impact of the economics of higher energy storage levels is evident in that in 2020, newly-commissioned plants had a weighted average capacity factor of 42%, with an average DNI that was lower than for plants commissioned between 2010 and 2013, inclusive. Indeed, during the 2010 to 2013 period, the weighted average capacity factor for newly-commissioned plants was between 27% and 35%.

Both the early period of CSP development in Spain and the more recent one in China have been characterised by small, 50 MW projects. In China's case, these have predominantly been technology demonstration projects among 20 initial pilot schemes. However, in order to unlock economies of scale – and as competitive procurement has encouraged greater developer choice in plant specifications – average project sizes have risen over time. It is likely that future commercial projects will gravitate towards the 100 MW to 150 MW range, which represents the economic optimum in most locations.

CSP plants are also now routinely being designed to meet evening peaks and overnight demand. CSP with low-cost thermal energy storage can integrate higher shares of variable solar and wind power, meaning that while often underrated, CSP could play an increasingly important role in the future.

The recent increase in storage capacity has also been driven by declining costs of thermal energy storage as the market has matured. This is the result of both declining capital costs and of higher operating temperatures, which allow larger temperature differentials in the molten salt storage systems, increasing the energy stored for the same volume. The result has been an increase in the weighted average number of storage hours through time. This rose more than three-fold between 2010 and 2020, from 3.5 hours to 11 hours. The Cerro Dominador project in Chile that came online in 2021 features the highest known storage capacity in the word, at 17.5 hours (Figure 5.5).

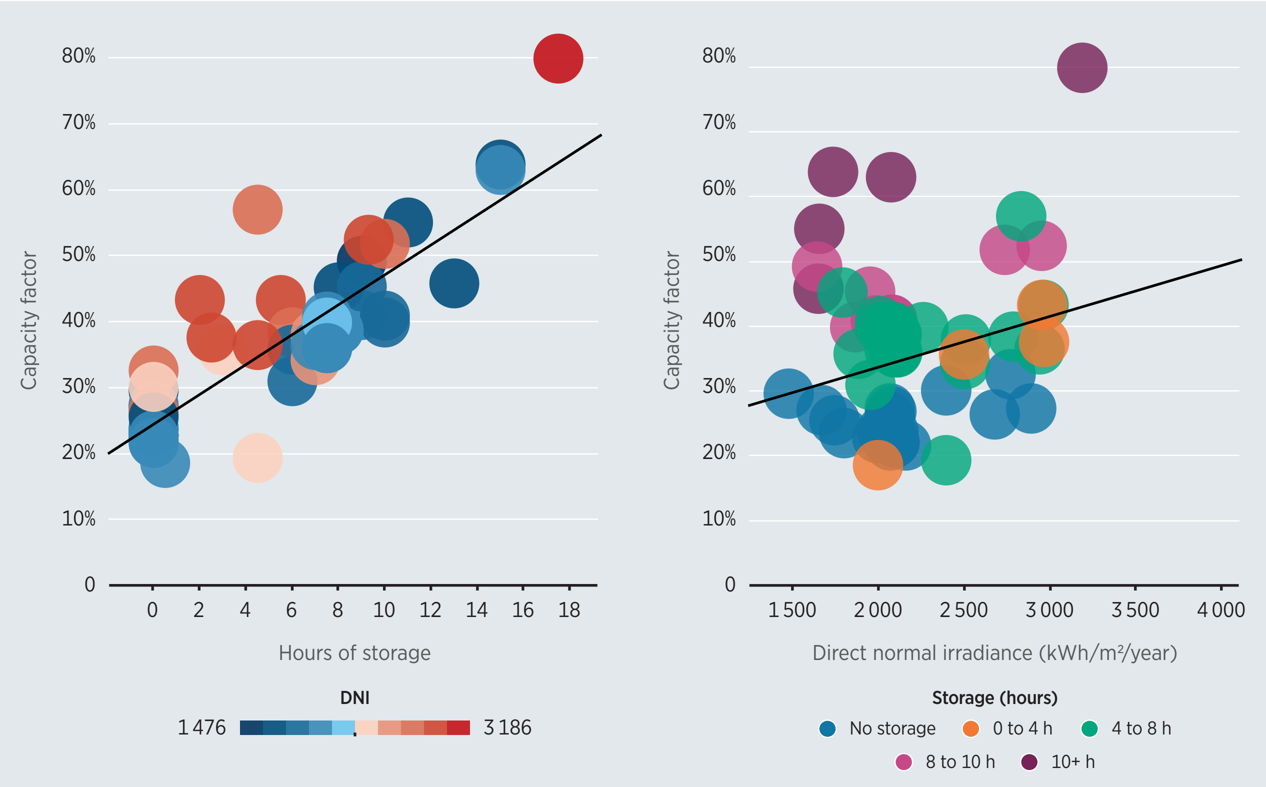
Figure 5.5 Average project size and average storage hours of CSP projects, 2010-2021



Source: IRENA Renewable Cost Database.

Although higher direct normal irradiation (DNI) leads to larger capacity factors, all else being equal, there is a much stronger correlation between capacity factors and storage hours. This is, however, only one part of the economics of plants at higher DNI locations. Higher DNIs also reduce the field size needed for a given project capacity – and hence the investment (Figure 5.6).

Figure 5.6 Capacity factors, storage hours and the solar resource, 2010-2021



Source: IRENA Renewable Cost Database.

Yet, technology improvements and cost reductions for thermal energy storage also mean that higher capacity factors can be achieved even in areas without world class DNI. The 2020 data show the impact of higher storage levels, with newly-commissioned plants recording a weighted average capacity factor of 42% that year, even though the average DNI in 2020 was lower than for plants commissioned between 2010 and 2013, inclusive. During that earlier period, the weighted average capacity factor was between 27% and 35% for newly commissioned plants.

OPERATION 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, which is 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.

In addition, 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 further contributor to O&M costs, 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 this is 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).

Analysis by IRENA undertaken in collaboration with the Institute of Solar Research (*Das Institut für Solarforschung des Deutschen Zentrums für Luft- und Raumfahrt* [DLR]) shows, however, that more competitive O&M costs are possible in a range of markets (Table 5.1) where projects achieved financial closure in 2019 and 2020.

The O&M costs per kWh in many of these markets are high in absolute terms, compared to solar PV and many onshore wind farms, but are about 18% to 20% of the LCOE for projects in G20 countries. Taking this into account, the LCOE calculations in the following section reflect O&M costs in the IRENA Renewable Cost Database that declined from a capacity weighted average of USD 0.037/kWh in 2010 to USD 0.015/kWh in 2020 (a 59% decline). The corresponding 2021 value is USD 0.022/kWh (40% lower than in 2010).

Table 5.1 All-in (insurance included) O&M cost estimates for CSP plants in selected markets, 2019-2020

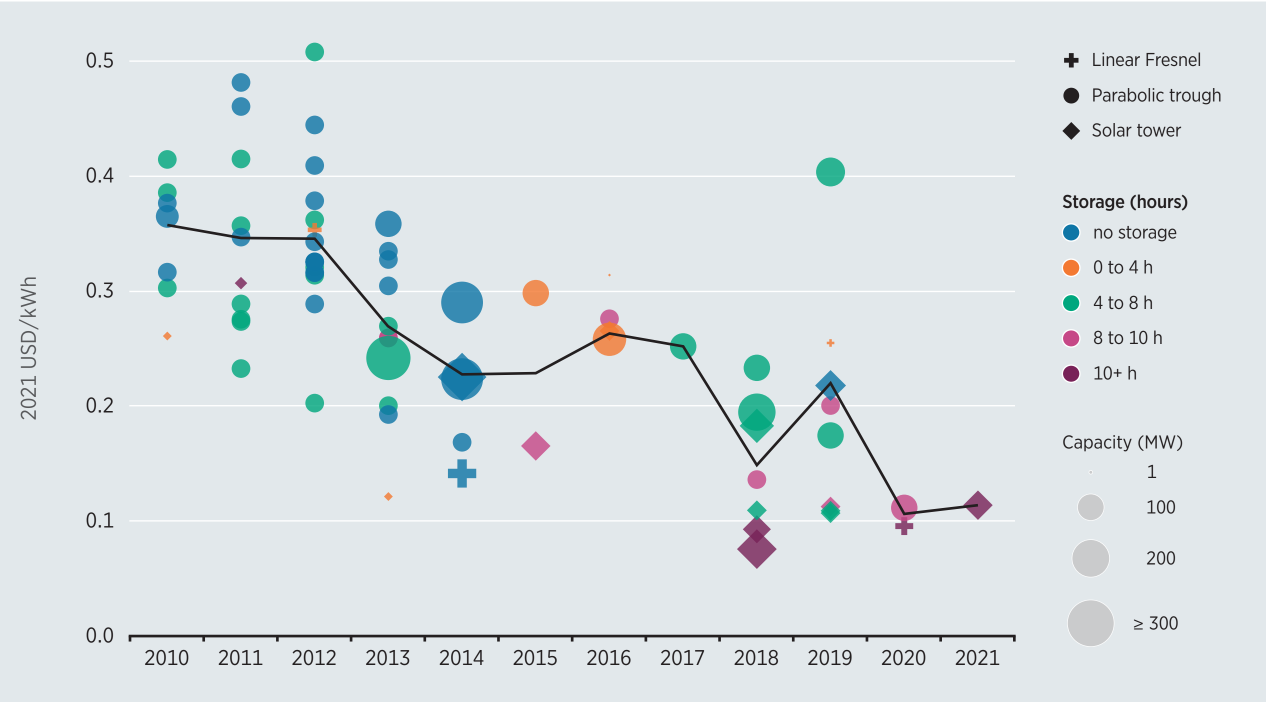
Country	Parabolic trough collectors	Solar tower
	(2021 USD/kWh)	(2021 USD/kWh)
Argentina	0.026	0.024
Australia	0.028	0.027
Brazil	0.021	0.021
China	0.022	0.019
France	0.033	0.028
India	0.016	0.016
Italy	0.026	0.024
Mexico	0.017	0.016
Morocco	0.013	0.012
Russian Federation	0.025	0.023
Saudi Arabia	0.012	0.011
South Africa	0.013	0.012
Spain	0.025	0.023
Türkiye	0.019	0.017
United Arab Emirates	0.019	0.021
United States of America	0.025	0.022

Source: IRENA Renewable Cost Database.

LEVELISED COST OF ELECTRICITY

With total installed costs, O&M costs and financing costs all falling, while capacity factors rose, the LCOE for CSP fell significantly between 2010 and 2020. Indeed, Over that period, the global weighted average LCOE of newly commissioned CSP plants fell by 70%, from USD 0.361/kWh to USD 0.107/kWh (Figure 5.7).

Figure 5.7 LCOE for CSP projects by technology and storage duration, 2010-2021



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 0.14/kWh. At the same time, projects commissioned in 2018 and 2019 in Morocco and South Africa tended to have higher costs than this.

For projects commissioned between 2014 and 2017, their location in places with higher DNIs was a major contributor to increased capacity factors (and therefore lower LCOE values). The weighted average DNI of projects commissioned during that period, at around 2 600 kWh/square metre (m^2)/year, was 28% higher than in the period 2010 to 2013. As already noted, however, this was not the only driver of LCOE trends, as technological improvements saw a move 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.

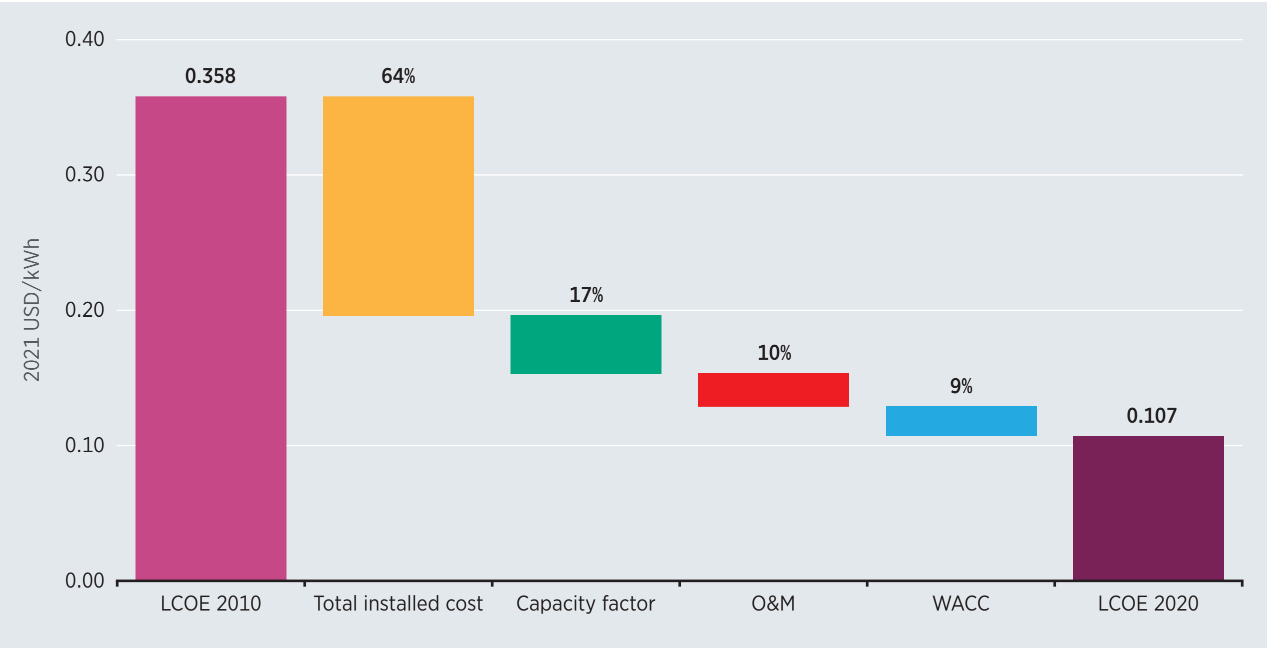
In 2016 and 2017, only a handful of plants were completed, with around 100 MW added in each year. The results for these two years are therefore volatile and driven by specific plant costs. In 2016, the increase in LCOE was driven by the higher costs of the early projects in South Africa and Morocco commissioned 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 at least 600 MW added in each year. In 2018, plants were commissioned in China, Morocco and South Africa, with LCOEs ranging from a low of USD 0.076/kWh in China, to a high of USD 0.234/kWh in South Africa. In contrast, 2019 saw higher LCOEs, as two delayed Israeli projects came online. Costs that year ranged from USD 0.107/kWh for a project in China to USD 0.404/kWh for the Israeli PTC project.

Deployment in 2020 did not exceed 150 MW, though low capital costs for the projects occurring in China pushed down the weighted average LCOE for that year to USD 0.107/kWh. In 2021, the LCOE value was 7% higher than in 2020, at USD 0.114/kWh – although this was still 68% lower than in 2010. The 2021 figure was, however, based on a very thin market.

Figure 5.8 unpacks[56] the 68% decline in global weighted average LCOE of CSP over the period 2010 to 2020, showing its main constituents.

Figure 5.8 Reduction in LCOE for CSP projects, 2010-2020, by source



Source: IRENA Renewable Cost Database.

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

At 64%, the largest share of the reduction was taken by 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 17% of the reduction in LCOE over the 2010 to 2020 period. Lower O&M costs accounted for 10% of the total decline in LCOE during that time, while the reduction in the weighted average cost of capital accounted for the remaining 9%.

The global weighted average LCOE of CSP declined by 68% over the period 2010-2020

This same analysis yields quite different results for the period 2010 to 2021, given the high total installed costs/high capacity factor structure of the 2021 project in Chile. Accounting for this results in the capacity factor being the major contributor (77%) to cost reduction between 2010 and 2021. Lower O&M costs account for a tenth of the reduction, while reductions in the global weighted average total installed costs of newly commissioned CSP plants accounted for 7%. Improvements in the weighted average cost of capital account for 6% of the total decline in LCOE over the period.

In the absence of strong policy support for CSP, the market remains small and the pipeline for new projects unambitious. This is disappointing, given the remarkable success in reducing costs since 2010, despite just 6.4 GW being deployed globally by the end of 2021. 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 bringing costs down even further – and in reducing overall electricity system costs – by providing firm, renewable capacity and flexibility services to integrate very high shares of renewables.

Box 5.1 Improving the performance of CSP plants

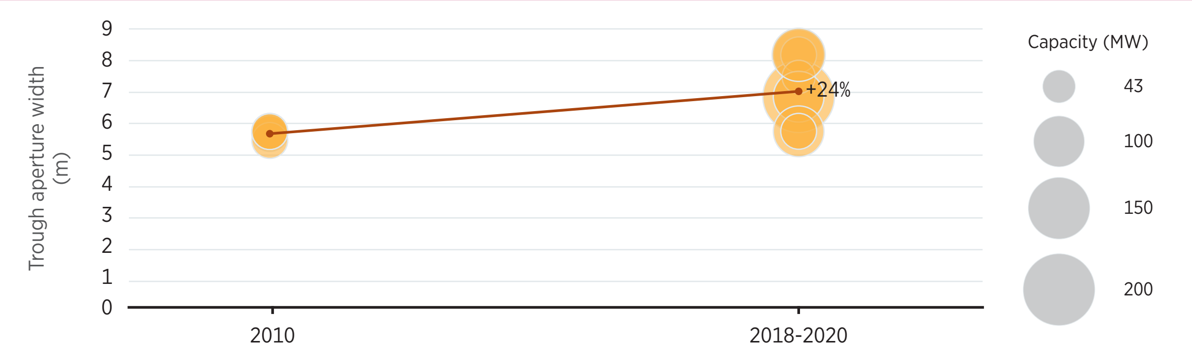
Figure B5.1 shows the development of selected performance metrics for major CSP commercial technologies.

For PTCs, cost reductions have been pursued by trying to reduce the costs of the parabolic troughs themselves and by improving their performance. Essentially, the challenge has been to raise absorption of solar heat and reduce heat losses in the HTF conveyed to the power block, while at the same time, reducing the capital cost of the components.

Improvements in special coatings on the absorber tube and insulation measures for the receiver have helped reduce thermal losses. To reduce capital costs, efforts have focused on reducing materials costs relative to heat generation. To the extent possible, given the loads on the structure, light-weighting of the mirrors and supporting frameworks has been pursued. Aperture widths have also been increased to allow for greater solar radiation to be focused.

Between 2010 and the 2018-2020 period, the weighted average aperture width of the parabolic troughs used in projects increased from around 5.7 metres (m) to around 7 m. In 2010, Spanish projects were dominant, using troughs with widths in the relatively narrow range of 5.5 m to 5.8 m. In the period 2018 to 2020, although deployment had slowed, it was more geographically diverse and used a wider range of troughs. These went from 5.8 m widths – not dissimilar to those used in two projects in 2010 – to larger, 8.2 m 'space tube' troughs.

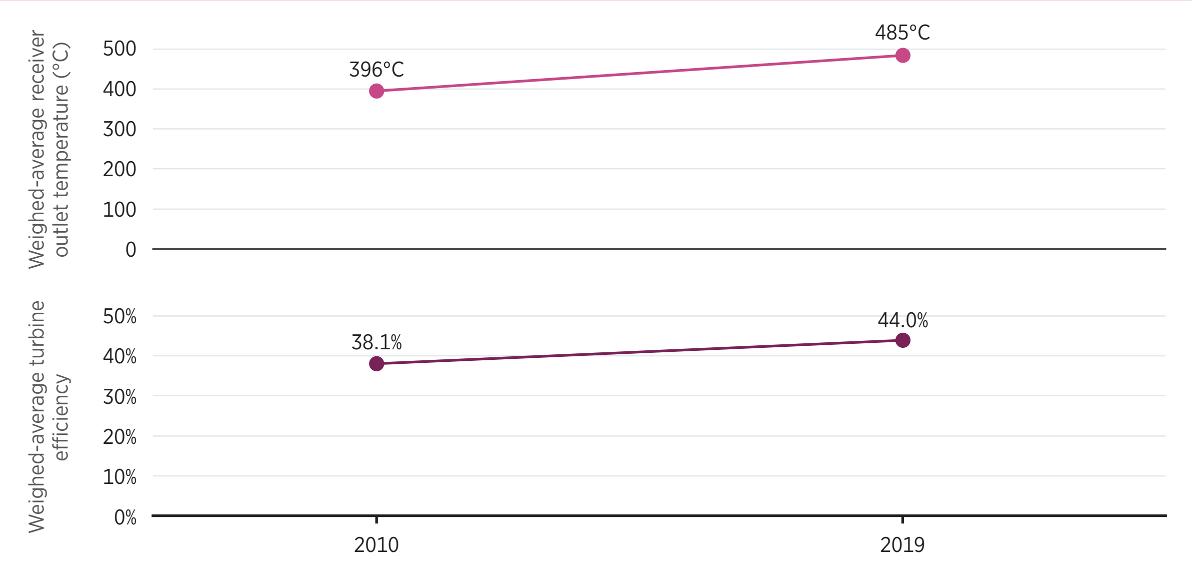
Figure B5.1 Trough aperture width trends for PTC CSP plants (2010-2018/2020)



Source: IRENA Renewable Cost Database; CSP Guru, 2021.

With an increased share of STs in deployment, the increased operating temperatures made possible by the use of molten salt HTFs or direct steam generation saw weighted average receiver outlet temperatures increase. These rose from 396°C in 2010, when PTC plants represented all capacity added for which there is data, to 485°C in 2019, as STs with receiver outlet temperatures ranging from 560°C to 565°C were commissioned (Figure B5.2).

Figure B5.2 Receiver outlet temperatures and turbine efficiency trends for CSP plants (2010-2019)

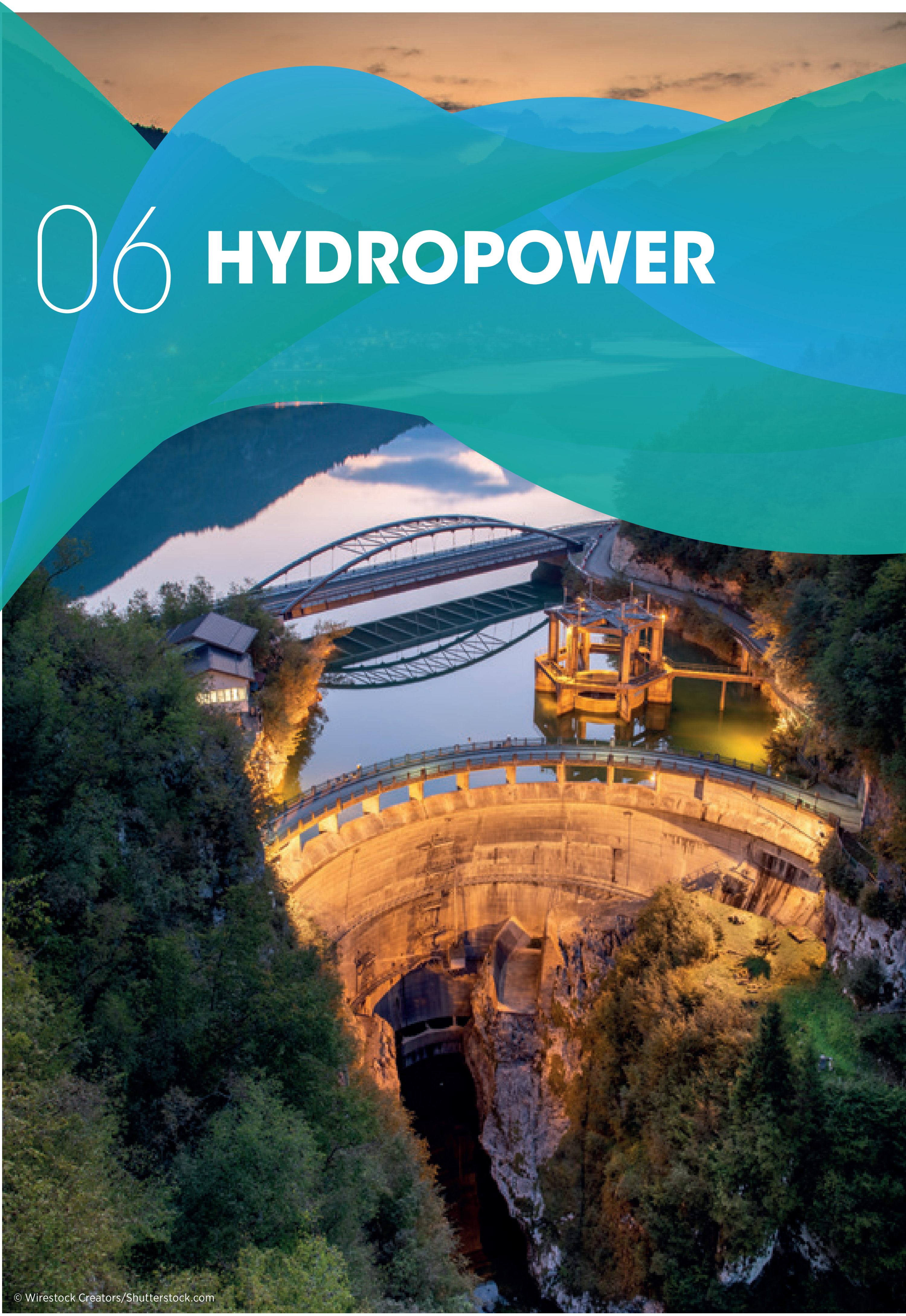


Source: IRENA Renewable Cost Database; CSP Guru, 2021.

Higher temperature differentials in the hot and cold tanks allow greater energy to be stored for a given volume. Yet, the benefit of higher operating temperatures is not just lower cost thermal energy storage, but also that they allow more efficient steam cycles to recover more electricity from the available resource. With the increasing share of STs, the weighted average turbine efficiency for projects where data is available rose from 38% in 2010 to 44% in 2019.

Efforts continue to commercialise molten salts as an HTF for PTC plants, since it can lead to higher HTF temperatures (530°C) than the currently prevalent thermal oil (393°C). Silicon-based HTF have also been proposed as an alternative and can achieve 425°C (Jung *et al.*, 2015). However, for the moment, the largest efficiency gains and greatest potential for longer storage remains with ST plants that can already operate at higher temperatures and efficiencies. Greater scale in the deployment of STs would also help to narrow their installed cost premium over PTC plants, potentially allowing STs a decisive advantage over PTCs in LCOE terms, in locations where the air is clear.

06 HYDROPOWER



HIGHLIGHTS

- The global weighted average LCOE of newly commissioned hydropower projects in 2021 was USD 0.048/kWh – 4% higher than the USD 0.046/kWh recorded in 2020 and 23% higher than the projects commissioned in 2010 (Figure 6.1).

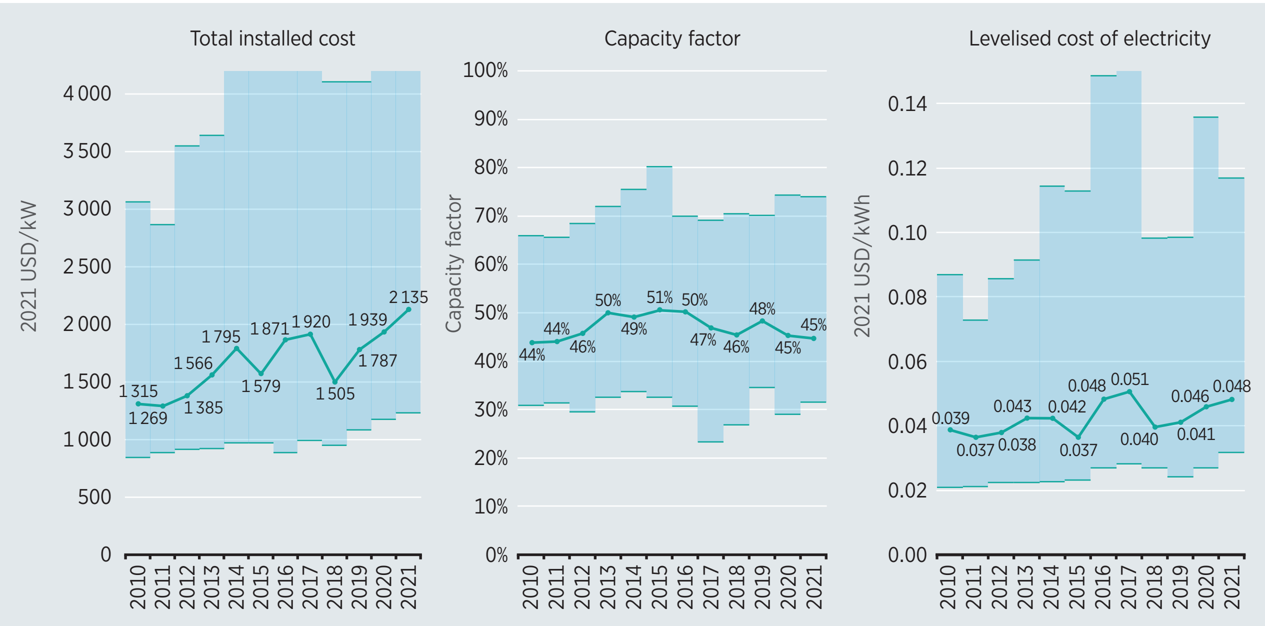
- With the cost of the newly commissioned fossil-fuel fired capacity ranging between USD 0.054/kWh and USD 0.167/kWh, 97% of the hydropower projects commissioned in 2021 had an LCOE within or lower than this range. Moreover, 85% of the hydropower capacity commissioned in 2021 had an LCOE lower than the 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 2021, the global weighted average total installed cost of newly commissioned hydro projects increased to USD 2135/kW, higher than the USD 1939/kW in 2020. Despite the higher share of deployment occurring in China in 2021 – 15 GW compared to 12 GW in 2020 – the global weighted average total installed cost in 2021 was the highest recorded value since 2010. This increase came despite the increased level of deployment occurring in China, which generally has lower-than-average installed costs; 15 gigawatts (GW) were installed there in 2021, compared to 12 GW in 2020. This level was not enough, however, to compensate for the higher share of installed capacity deployment in countries or regions with higher average installed costs than China. In Canada, for example, 1.3 GW was added in 2021 with one large relatively remote project coming on line in Manitoba, while there was also a higher share of deployment in Eurasia and Other Asia in 2021 compared to 2020 – all locations with higher than average installed costs.

- Between 2010 and 2021, 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 2021, it was 45%.

Figure 6.1 Global weighted average total installed costs, capacity factors and LCOE for hydropower, 2010-2021



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 40% in 2021. By the end of that year, however, total global installed hydropower capacity (excluding pumped hydro) had risen to 1 230 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.

In addition, hydropower plants fall into three categories:

- Reservoir - or storage - hydropower, 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) 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 2021 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.

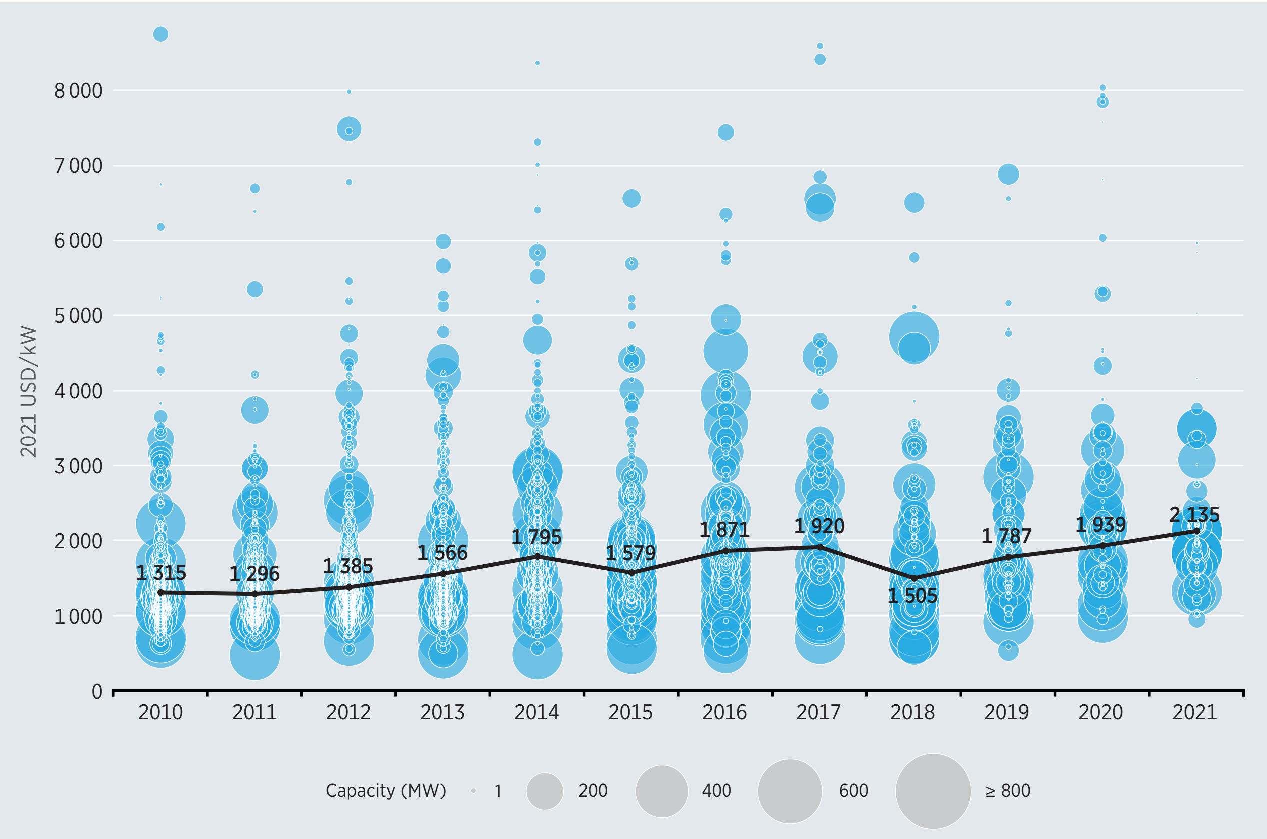
Between 2010 and 2021, the global weighted average total installed cost of new hydropower rose from USD 1 315/kW to USD 2 135/kW. After rising steadily between 2010 and 2014, there was considerable volatility, year-on-year between then and 2020 within a range broadly bound by USD 1 500/kW and USD 1 940/kW. The year 2021 represented a new, higher cost level, with increases driven not just by the share of deployment in different regions, but also an upward trend in project-specific costs.

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 and Europe 2021.

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
Europe 2021			
Type of Hydro	**Share of total installed costs (%)**		
	Civil	**Mechanical**	**Electrical**
Large-scale Reservoir Storage (high head)	70	10	20
Large-scale Run of river (low head)	50	30	20
Small-scale Run of river	50	30	20
Pumped storage	30-50	20-30	30-40

Source: IRENA Renewable Cost Database and International Hydropower Association (IHA).

Figure 6.2 Total installed costs by project and global weighted average for hydropower, 2010-2021



Source: IRENA Renewable Cost Database.

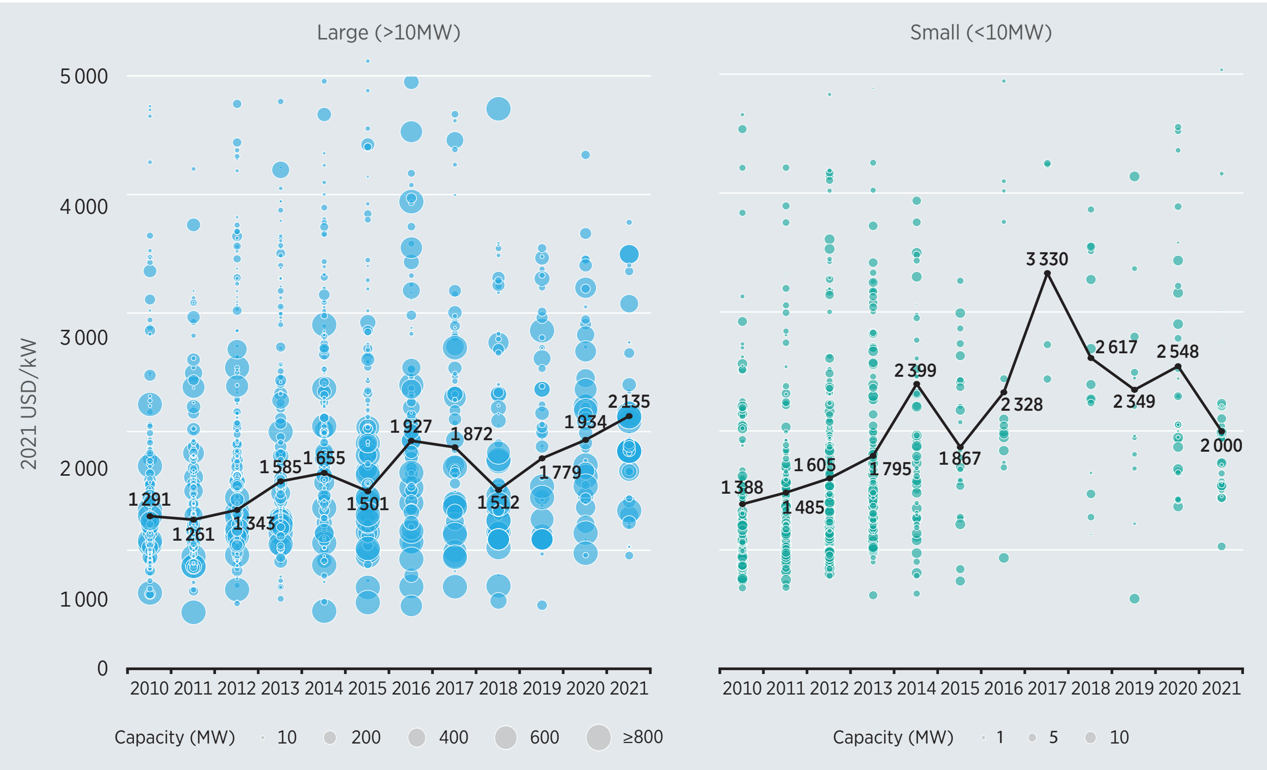
The increase has been driven by rising installed costs for projects in Asia, Europe and North and South America. The data appears to suggest that behind this is the fact that many countries in these regions are now developing hydropower projects at less ideal sites. Such projects maybe located further from existing infrastructure, or the transmission network, resulting in higher logistical costs, as well as boosting grid connection costs. They may also be in locations with more challenging geological conditions, requiring more extensive and expensive work for the construction of the dam itself. 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 2021 (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 2021.

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, 2010-2021



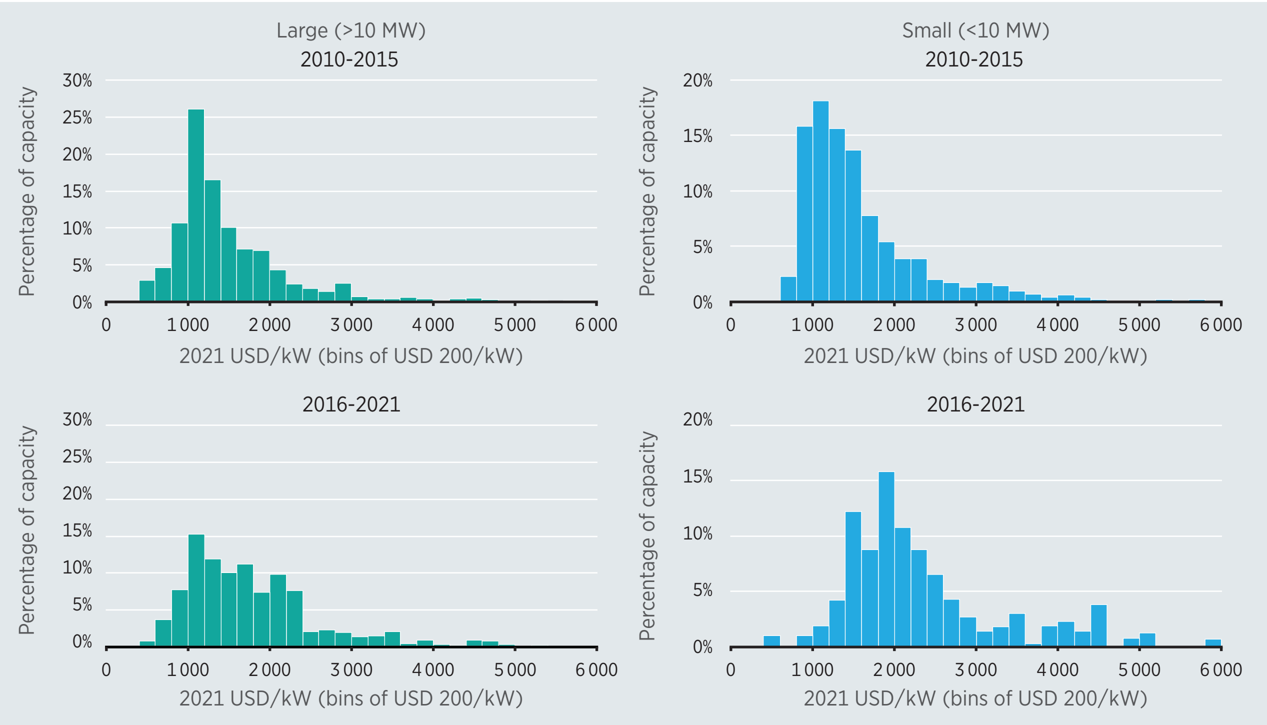
Source: IRENA Renewable Cost Database.

Table 6.2 Total installed costs for hydropower by weighted average and by capacity range, 2000-2021

2000-2021			
Capacity (MW)	**5th percentile (2021 USD/kW)**	**weighted average (2021 USD/kW)**	**95th percentile (2021 USD/kW)**
0-50	838	**1 634**	3 563
51-100	875	**1 842**	3 762
101-150	923	**1 756**	3 516
151-200	837	**1 729**	3 138
201-250	920	**1 789**	3 404
251-300	838	**2 086**	3 869
301-350	930	**1 990**	4 490
351-400	675	**1 691**	3 294
401-450	1 197	**1 995**	3 064
451-500	988	**1 592**	2 571
501-550	1 114	**1 998**	3 500
551-600	1 355	**1 829**	2 593
601-650	1 071	**1 452**	3 352
651-700	770	**1 997**	2 685
701-750	966	**1 442**	2 034
751-800	1 071	**1 574**	2 222
801-850	1 178	**1 833**	2 626
851-900	956	**1 628**	1 862
901-950	658	**1 101**	1 338

Source: IRENA Renewable Cost Database.

Figure 6.4 Distribution of total installed costs of large and small hydropower projects by capacity, 2010-2015 and 2016-2021



Source: IRENA Renewable Cost Database.

Compared to the period 2010 to 2015, the data for 2016 to 2021 shows a reduction in the share of newly commissioned projects in the USD 600/kW to USD 1200/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 2021 period, the total installed costs for large hydropower (more than 10 MW) were highest in the Oceania and North America regions. In these two areas, there were weighted average installed costs of USD 4 128/kW and USD 3 588kW respectively. The next highest cost was in Central America and the Caribbean, where the weighted average was USD 3 576/kW.

The lowest installed costs for large hydropower were in India and Brazil (Figure 6.5). There, the weighted average installed cost was USD 1 432/kW in India, while in Brazil it was USD 1 521/kW. In China, the cost was USD 1 596/kW, while in Other Asia it was USD 1 755/kW. In the Middle East, the cost was USD 1 787/kW, while in Europe it was USD 2 050/kW. In Eurasia, Other South America and Africa the weighted average installed costs were USD 2 203/kW, USD 2 233/kW and USD 2 535/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.

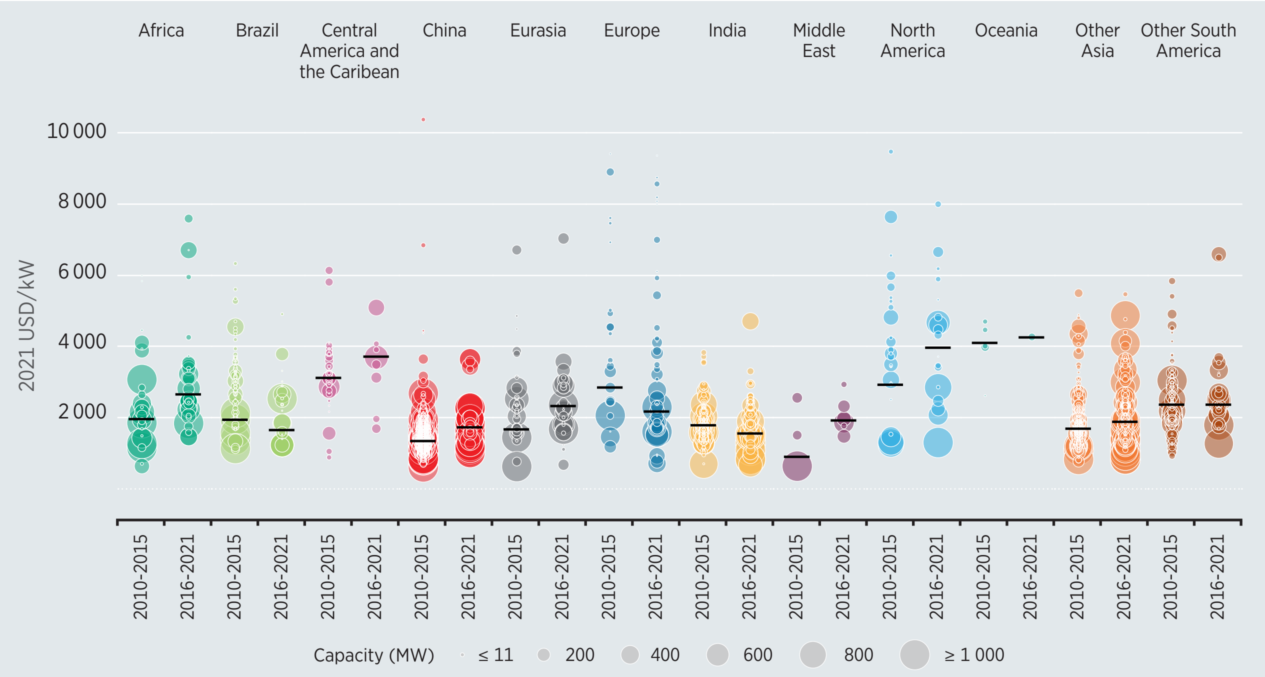
A comparison between installed costs for large and small hydro plants shows that small hydro plants generally have between 20% and 80% higher installed costs when compared to large hydro plants. The exceptions are in the Central America and the Caribbean and Oceania regions, where installed costs are 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 2021 in India were USD 1 864/kW, which is somewhat higher than in the period 2010 to 2015. The total installed costs of small hydropower in Brazil averaged USD 2 213/kW in the period 2016 to 2021, a figure 7% lower than in the period 2010 to 2015. The weighted average installed cost for small hydropower in China was USD 1 214/kW over the period 2010 to 2015, with the data for the period 2016 to 2021 limited and unrepresentative.

The data for small hydropower projects commissioned in the period 2016 to 2021 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.

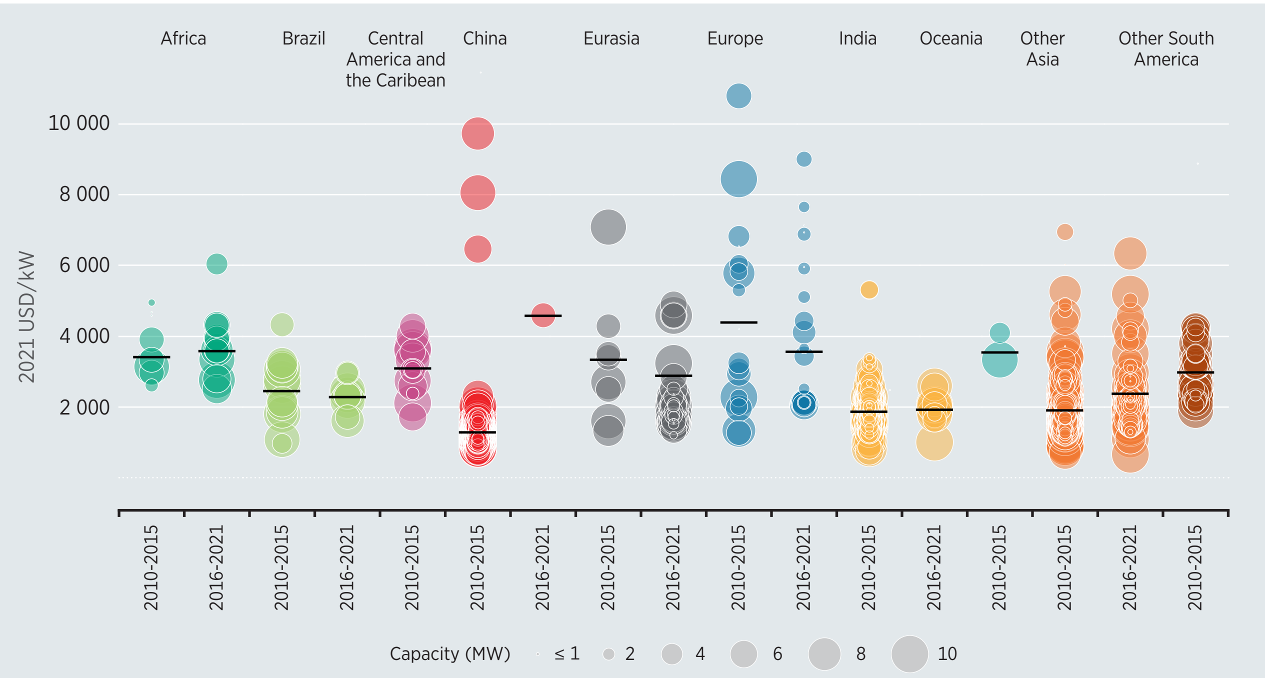
The weighted average installed cost for small hydropower in Oceania was USD 3 485/kW over the period 2010 to 2015, while in Central America and the Caribbean it was USD 3 032/kW and in Other South America USD 2 912/kW.

Figure 6.5 Total installed cost by project and capacity weighted averages for large hydropower projects by country/region, 2010-2021



Source: IRENA Renewable Cost Database.

Figure 6.6 Total installed costs by project and capacity weighted averages for small hydropower projects by country/region, 2010-2021



Source: IRENA Renewable Cost Database.

CAPACITY FACTORS

Between 2010 and 2021, the global weighted average capacity factor of newly commissioned hydropower projects of all sizes increased from 44% to 45%. The average increase over the period, however, was 47%, with the 5th and 95th percentiles of projects within the 23% to 80% range. 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 and non-energy services, like flood control, where water levels may be kept deliberately low at certain times of the year.

The average capacity factor for projects commissioned between 2010 and 2021 was 48% for large hydro projects and 50% for small, 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 2021, the annual global weighted average capacity factors of the 5th percentile of large hydropower projects ranged from a low of 23% in 2017, to a high of 36% in 2021. For the 95th percentile, the figure ranged from a low of 61% in 2010, to a high of 80% in 2015. The figure for 2021 was 64%.

Over the same period, the global weighted average capacity factor of newly-commissioned small hydropower projects increased from 48% in 2010 to 57% in 2021. Excluding the years 2017 and 2018 where there is a lack of data, between 2010 and 2021 the annual, global weighted average capacity factors of the 5th percentile of small hydropower projects ranged from a low of 29% in 2012 to a high of 39% in 2016. For the 95th 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 2021, South America maintained the highest average capacity factor, at 60%, followed by 54% 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 2021, Europe had the lowest recorded, at 35%.

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 2021, respectively. Similarly, weighted average capacity factors for newly-commissioned small hydropower projects between 2010 and 2015 were highest in Other South America and Brazil, with 65% and 63%, respectively.

Between 2015 and 2021, 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 58%, followed by Other Asia, with a factor of 56%, while weighted average capacity factor in Africa and Brazil dropped to 55% and 54%%, respectively.

Table 6.3 Hydropower project capacity factors and capacity weighted averages for large hydropower projects by country/region, 2010-2021

	2010-2015			2016-2021		
	5th percentile (%)	Weighted average (%)	95th percentile (%)	5th percentile (%)	Weighted average (%)	95th percentile (%)
Africa	28	**47**	71	34	**54**	79
Brazil	51	**61**	80	39	**45**	57
Central America	27	**48**	63	33	**51**	55
China	31	**45**	57	35	**46**	55
Eurasia	28	**43**	61	29	**42**	66
Europe	14	**41**	70	16	**35**	58
India	29	**47**	63	21	**42**	60
North America	18	**37**	78	34	**52**	72
Oceania	25	**38**	47	n.a.	**n.a.**	n.a.
Other Asia	37	**46**	65	37	**49**	74
Other South America	46	**62**	85	47	**60**	79

Source: IRENA Renewable Cost Database.

Table 6.4 Hydropower project capacity factors and capacity weighted averages for small hydropower projects by country/region, 2010-2021

	2010-2015			2016-2021		
	5th percentile (%)	Weighted average (%)	95th percentile (%)	5th percentile (%)	Weighted average (%)	95th percentile (%)
Africa	33	**56**	68	51	**55**	65
Brazil	42	**63**	88	49	**54**	59
Central America	45	**59**	75	n.a.	**n.a.**	n.a.
China	33	**46**	60	38	**38**	38
Eurasia	44	**58**	74	43	**58**	71
Europe	23	**48**	70	28	**43**	66
India	28	**50**	71	39	**54**	61
Other Asia	37	**50**	79	36	**56**	76
Other South America	43	**65**	82	n.a.	**n.a.**	n.a.

Source: IRENA Renewable Cost Database.

OPERATION AND MAINTENANCE COSTS

Annual operation and maintenance (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 photovoltaic (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 2021, the global weighted average cost of electricity from hydropower was USD 0.048/kWh, up 24% from the USD 0.039/kWh recorded in 2010. The global weighted average cost of electricity from hydropower projects commissioned in years 2010 to 2015 averaged USD 0.041/kWh. This increased to an average of USD 0.054/kWh for projects commissioned over the years 2016 to 2021.

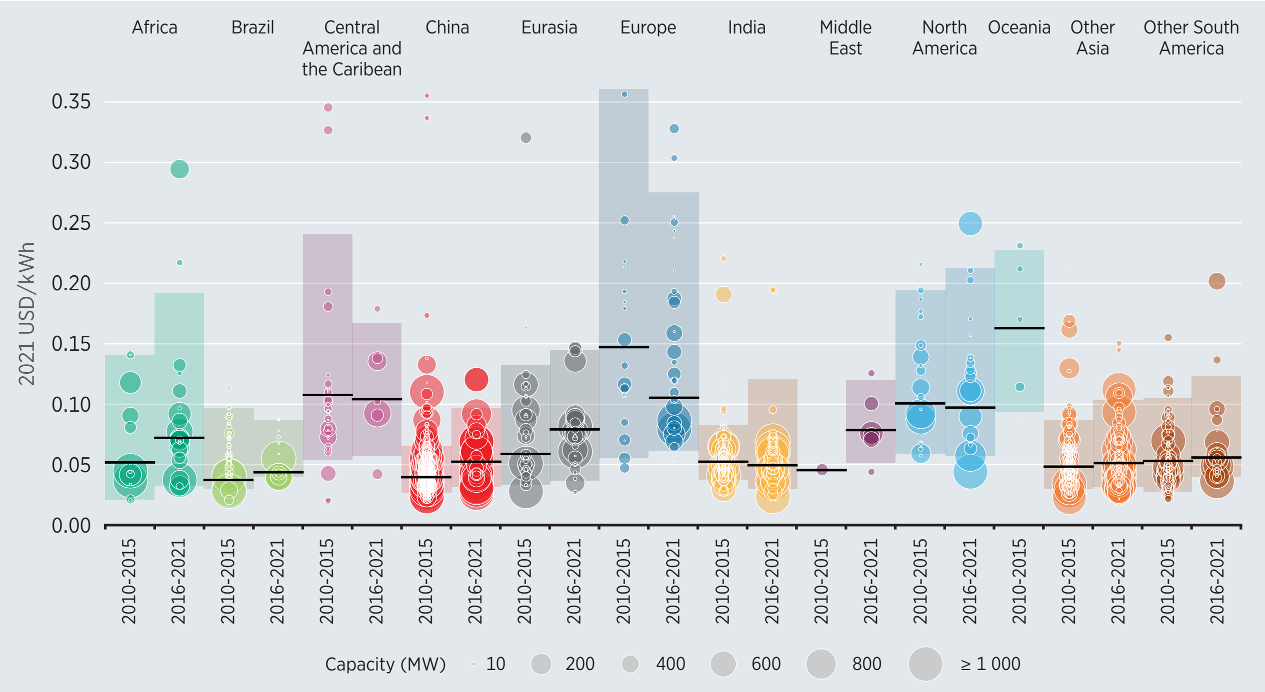
Despite these increases through time, however, 98% of the hydropower projects commissioned in 2021 had an LCOE within or lower than the range of newly commissioned fossil-fuel fired capacity cost. Moreover, 85% of the hydropower capacity commissioned in 2021 had an LCOE lower than the cheapest new fossil 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. In these locations, hydropower 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 2021 range from a low of USD 0.021/kWh in India for a 100 MW project to a high of USD 0.25/ kWh for a remote, 2 MW Indonesian project.

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 2021.

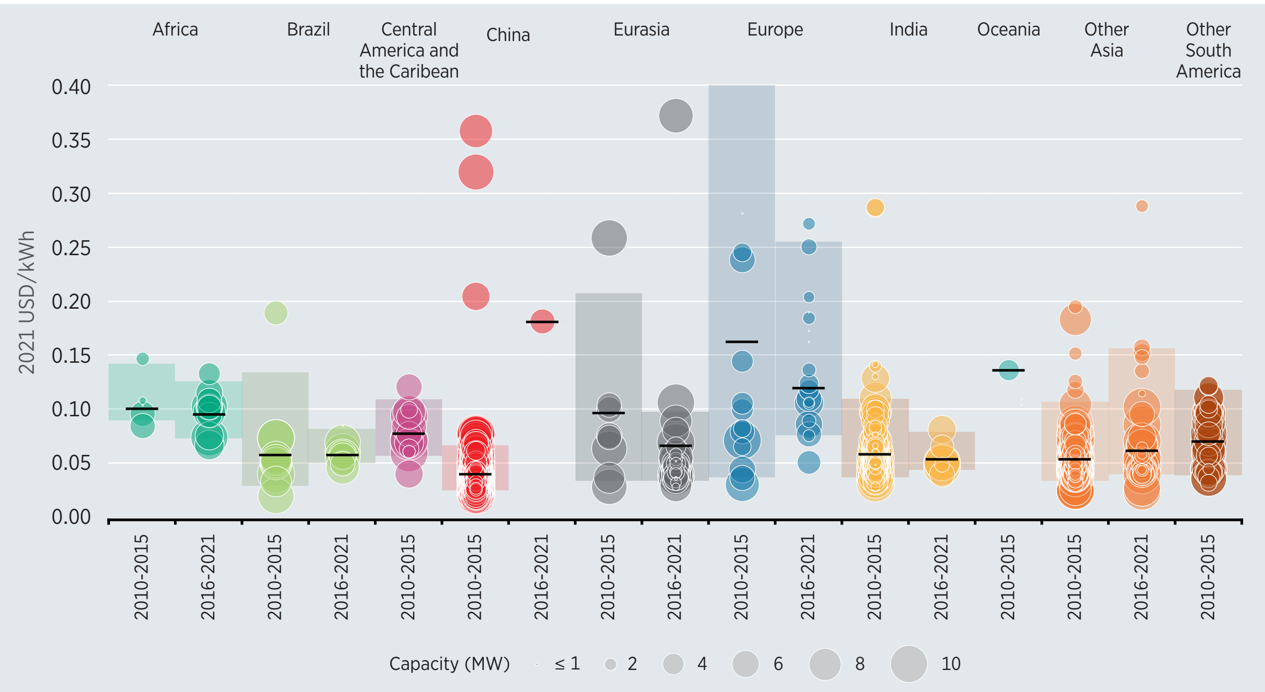
The exceptions were Europe, India and North America, where the weighted average LCOE decreased, while China saw a 31% increase in the weighted average LCOE between the periods 2010 to 2015 and 2016 to 2021. Small hydropower projects showed increase in the weighted average LCOE between the periods 2010 to 2015 and 2016 to 2021 in most of the countries and regions. There was, however, a different trend in Other Asia, where the weighted average LCOE increased.

Figure 6.7 Large hydropower project LCOE and capacity weighted averages by country/region, 2010-2021



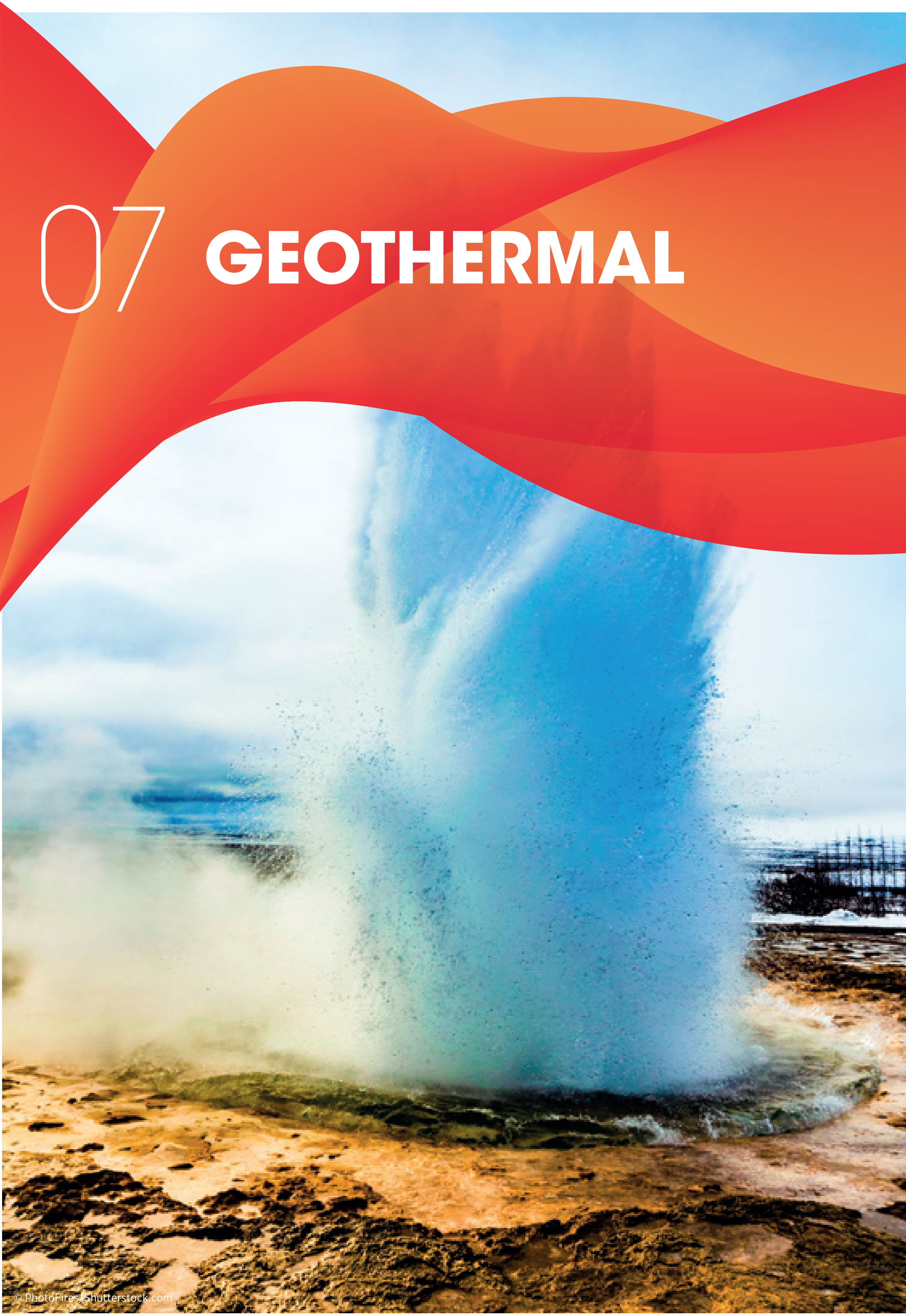
Source: IRENA Renewable Cost Database.

Figure 6.8 Small hydropower project LCOE and capacity weighted averages by country/region, 2010-2021



Source: IRENA Renewable Cost Database.

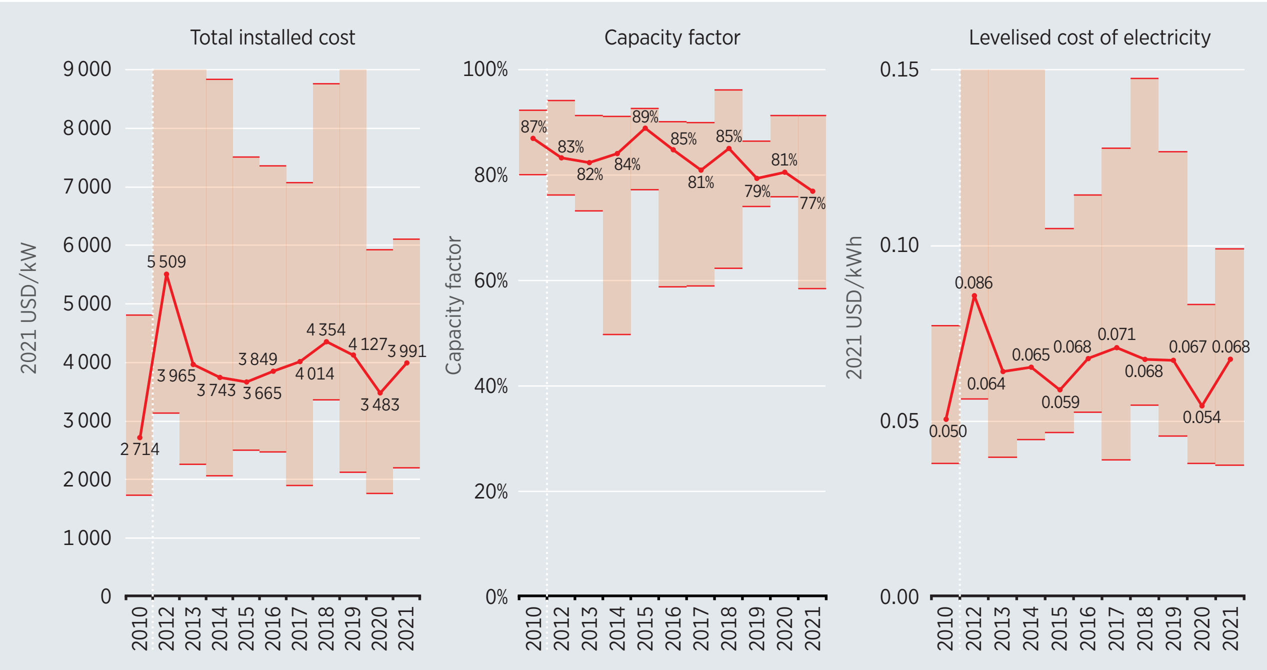
07 GEOTHERMAL



HIGHLIGHTS

- Worldwide, around 370 megawatts (MW) of new geothermal power generation capacity was commissioned in 2021. This was slightly higher than the 335 MW added in 2020.
- The global weighted average levelised cost of electricity (LCOE) of the projects commissioned in 2021 was USD 0.068/kilowatt hour (kWh). This was also up on the figure of USD 0.054/kWh recorded in 2020, while broadly in line with the values seen over the last five years.
- New capacity additions in 2021 were much lower than in 2015 – the decade's record year – when 655 MW was recorded. They were, however, higher than the annual levels recorded in the period 2010 to 2013 (inclusive) and in 2016 and 2020.
- The low deployment rate for geothermal means, though, that weighted average costs and performance are being determined by only a handful of plants in each year.
- In 2021, the global weighted average total installed cost of the eight plants in IRENA's database was USD 3 991/kW. This was higher than the recent low of USD 3 483/kW recorded in 2020, but lower than the values from 2017 to 2019. The total installed costs of the 11 projects commissioned in 2021 ranged from a low of USD 1 978/kW to a high of USD 6 548/kW for a 4 MW plant.
- Geothermal plants are typically designed to run as often as possible, in order to maintain constant flows from the reservoir and to provide power around the clock. In 2021, the global weighted average capacity factor for newly commissioned plants was 77%. This was lower than in recent years due to a project with a low estimated capacity factor that was completed in Türkiye. All the other projects commissioned in 2021 had estimated lifetime capacity factors of between 75% and 91%.

Figure 7.1 Global weighted average total installed costs, capacity factors and LCOEs for geothermal, 2010-2021



Source: IRENA Renewable Cost Database.

INTRODUCTION

At the end of 2021, geothermal power generation stations accounted for 0.5% of total installed renewable power generation capacity, worldwide, with a total installed capacity of around 14.4 gigawatts (GW). Cumulative installed capacity at the end of 2021 was 44% higher than in 2010. This capacity is mostly located in active geothermal areas. The countries with the largest installed capacities include the United States, Indonesia, Philippines, Türkiye, New Zealand, Mexico, Kenya and Italy.

The best geothermal resources are found in active geothermal areas on or near the surface of the Earth's crust. The key advantage of these resources is that they can be accessed at lower cost than the evenly distributed heat available at greater depths everywhere else on the planet. In active geothermal areas, shallow drilling into the earth's surface can cheaply tap into naturally occurring steam or hot water, which can then be used to generate electricity in steam turbines and/or provide heat to homes or industry.

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. These areas, with high-temperature water or steam at or near the surface are commonly referred to as 'active' geothermal areas. 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.

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; but development would likely always be riskier than in areas with active resources.

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. Subsurface resource assessments and reservoir mapping are expensive to conduct. They then need to be confirmed by test wells that allow developers to build models of the reservoir's extent and flow and how it will react to the extraction of water and steam for power generation.

Much, however, will remain unknown about how the reservoir will perform and how best to manage it over the operational life of the project before actual operational experience is gained.

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.

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 field 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, if flow rates or reservoir permeability is less than expected. 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 (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. Such experience may, however, provide broader industry knowledge that helps better inform other factors, from reservoir modelling to operation and maintenance (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) and their importance cannot be underestimated.

Another point of difference for geothermal plants is that once commissioned, the management of the plant and its reservoir evolves almost constantly over time in a way that is much more challenging than, for example, wind or solar photovoltaic (PV). The process of extracting reservoir fluid and reinjecting it over the life of the project creates a dynamic situation where reservoir fluid migration will likely change over time, with implications for the productivity of individual production wells. With more information becoming available from operational experience, operators' understanding of how to best manage the reservoir will also constantly evolve over time.

Another important consideration for geothermal power plants is that once productivity at existing wells declines, there will often be a need for replacement wells to make up for this loss. As a result, lifetime O&M costs are, on average, higher in fixed terms than for other renewable technologies. Yet, with higher capacity factors, they can be similar on a per kWh basis.

TOTAL INSTALLED COSTS

Geothermal power generation projects have, on average, relatively high capital costs compared to hydropower, solar PV and onshore wind, with installed costs more in line with offshore wind and concentrated solar power (CSP).

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.

In particular, geothermal power project costs are heavily influenced by the reservoir quality – that is to say temperature, flow rates and permeability – as this influences both the type of power plant and the number of wells required for a given capacity. The nature and extent of the reservoir, the thermal properties of the reservoir and its fluids — and at what depths they lie — will all have an impact on project costs.

In addition, the quality of the geothermal resource and its geographical distribution will determine the power plant type. This can be a ‘flash’, ‘direct steam’, ‘binary’, enhanced or 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 also include the costs of exploration and resource assessment (including seismic surveys and test wells). This cost category also applies to solar and wind resources, but resource assessment with weather stations costs much less.

The other main additional cost driver for geothermal is the drilling costs for the production and injection wells. If a large geothermal field needs to be exploited, the costs for field infrastructure, geothermal fluid collection and disposal systems, and other surface installations can also be significant.

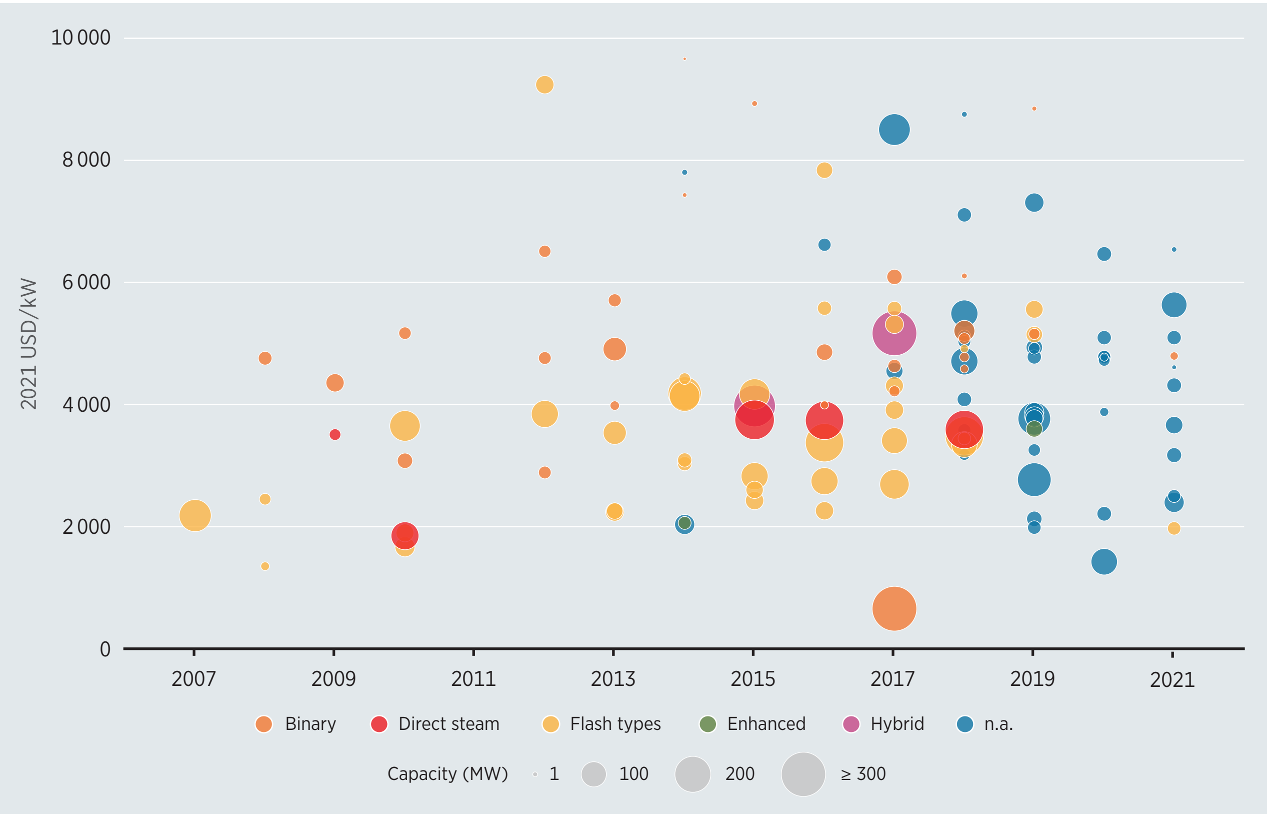
In line with rising commodity prices and drilling costs, between 2000 and 2009, the total installed costs for geothermal plants increased by between 60% and 70% (IPCC, 2011). Project development costs followed general increases in civil engineering and EPC costs during that period, with cost increases in drilling associated with surging oil and gas markets. Costs appear to have stabilised since, however, albeit with significant volatility due to thin markets up to 2015.

In 2009, the total installed costs of conventional condensing 'flash' geothermal power generation projects were between USD 2 097/kW and USD 4 183/kW. Binary power plants were more expensive and installed costs for typical projects were between USD 2 481 and USD 6 062/kW that same year (IPCC, 2011). Since 2010, most flash power plants for which IRENA has data were in the range USD 2 260 to USD 5 580/kW, and binary plants in the range of USD 2 890 to USD 5 210/kW.

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 6 000/kW, although there were a number of project outliers, especially for small and/or remotely located projects. Since 2013, the weighted average total installed cost has been relatively flat – with some inter-year variation – from a low of USD 3 483/kW in 2020 to a high of USD 4 354/kW, with an average of around USD 4 000/kW in that period. In 2021, the global weighted average total installed cost was USD 3 991/kW, higher than the recent low of USD 3 483/kW in 2020 and from the USD 2 620/kW reported in 2010, but lower than the values for 2017 to 2019 inclusive. 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, and it is now rare to see projects with costs below USD 2 000/kW.

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



Source: IRENA Renewable Cost Database.

CAPACITY FACTORS

By accessing the steam or heated water near the earth's surface, geothermal plants have a continuous source of energy and tend to operate most hours of the year.

For the years 2007 to 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, and to a lesser extent between countries, driven by the quality of the resource and reservoir dynamics, as well as by economic factors, to name just three of the most important drivers.

Figure 7.3 presents the capacity factors of geothermal power plant projects in the IRENA Renewable Cost Database by year, project size and technology.

The average capacity factor of geothermal plants using direct steam is around 88%, while the average for flash technologies is 83%. Binary geothermal power plants that harness lower temperature resources are expected to achieve an average capacity factor of 80%. In 2021, the global weighted average capacity factor for newly commissioned geothermal projects was 77%, down from 81% in 2020. The main driver of this decline is a single Turkish plant, with a reported lifetime capacity factor of 42%. Excluding this project raises the global weighted average for projects commissioned in 2019 to a more usual 84%.

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. Geothermal power plants tend to have higher installed costs, O&M costs and capacity factors than hydropower, some bioenergy plants, solar PV and onshore wind projects. The higher capacity factors help to offset the higher capital and operating costs, while also meaning the plant runs during most hours of the year.

Even more than with solar and wind technologies, geothermal power projects require continuous optimisation throughout their lifetime, with sophisticated management of the reservoir and production wells to ensure output meets expectations. This leads to higher O&M costs, with this LCOE analysis assuming O&M costs of USD 115/kW/year and an economic life of 25 years for the project. Capacity factors were taken from project data, where available, and where none was, national averages were used.

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 0.037/kWh for second stage development of an existing field to as high as USD 0.17/kWh for small greenfield developments in remote areas.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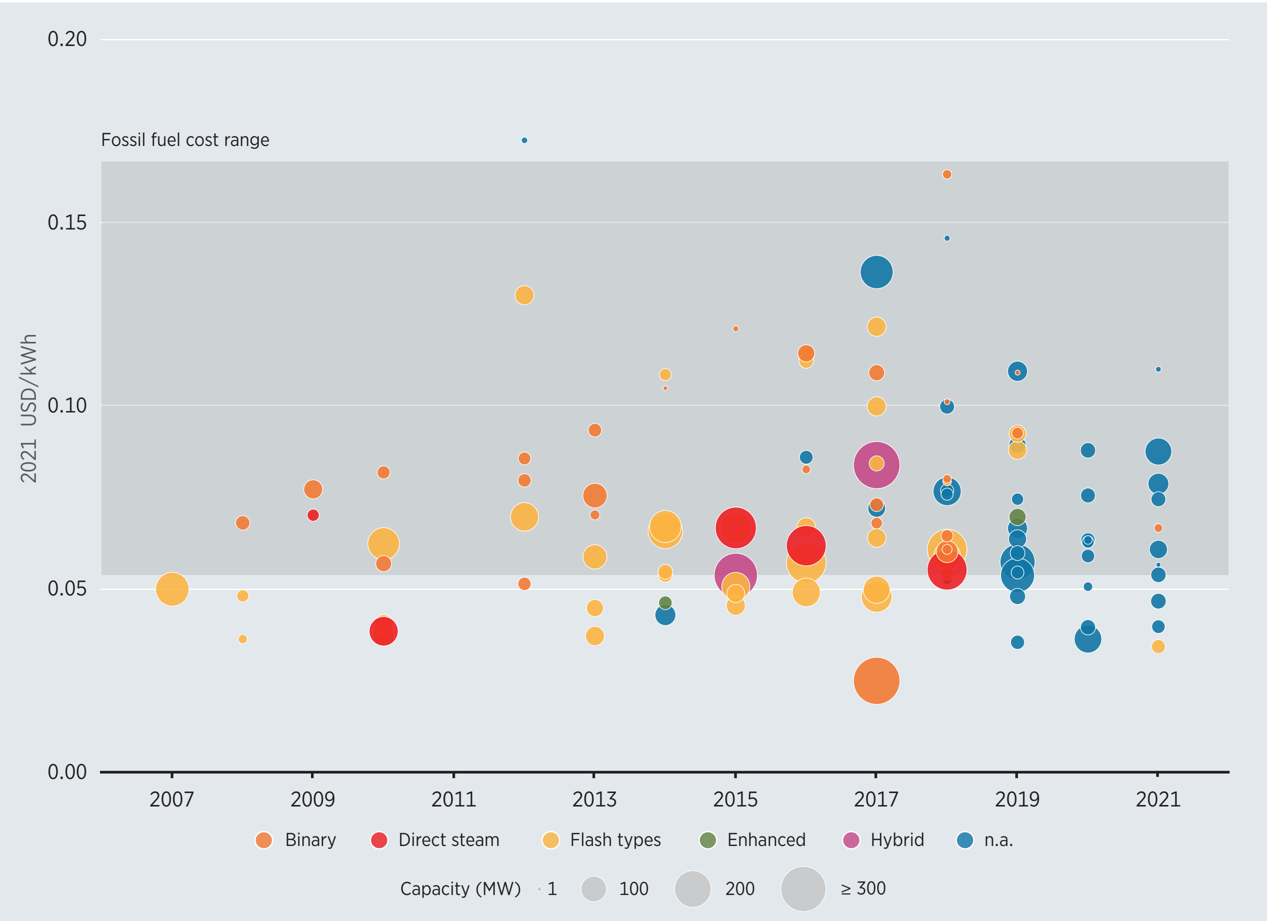
O&M costs for geothermal projects are high relative to onshore wind and solar PV, in particular, because over time the reservoir pressure around the production well declines, leading to poorer flow rates. Well productivity therefore reduces over time and eventually power generation production falls as 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 110/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.

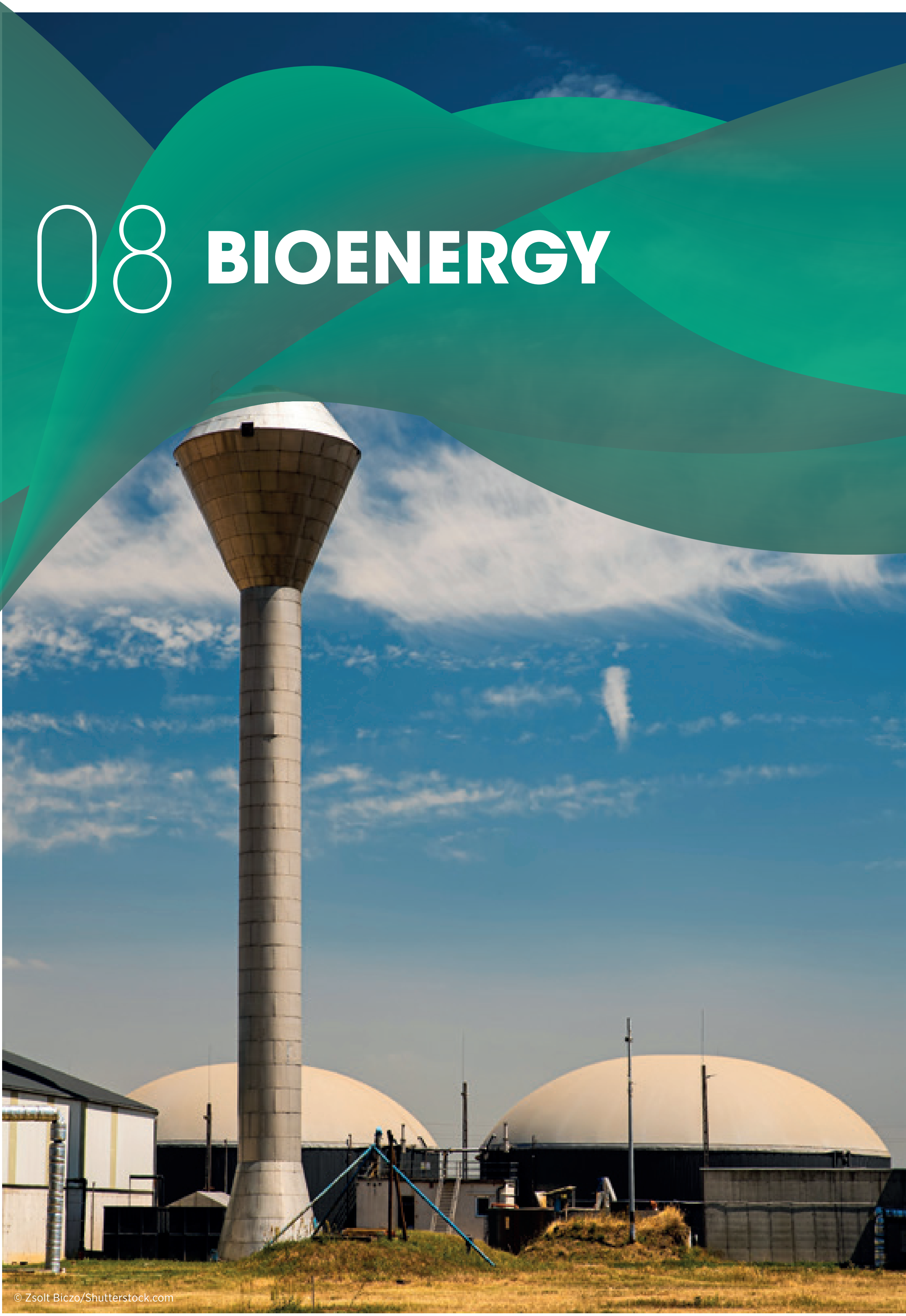
The global weighted average LCOE increased from around USD 0.05/kWh for projects commissioned in 2010 to around USD 0.068/kWh in 2021. Although there are annual variations in the global weighted average capacity factor of newly commissioned projects, this is often less significant than for bioenergy, for example, where significant cost differences occur between technologies and countries. With typically little variation in capacity factors, the LCOE of geothermal power projects tends to follow the trends in total installed costs. For the period 2016 to 2021, the data available suggests the LCOE was relatively stable for most years, with a global weighted average of between USD 0.065 and USD 0.071/kWh, with the exception of 2020, where a low of USD 0.054/kWh was driven by the commissioning of a very competitive Kenyan project.

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



Source: IRENA Renewable Cost Database.

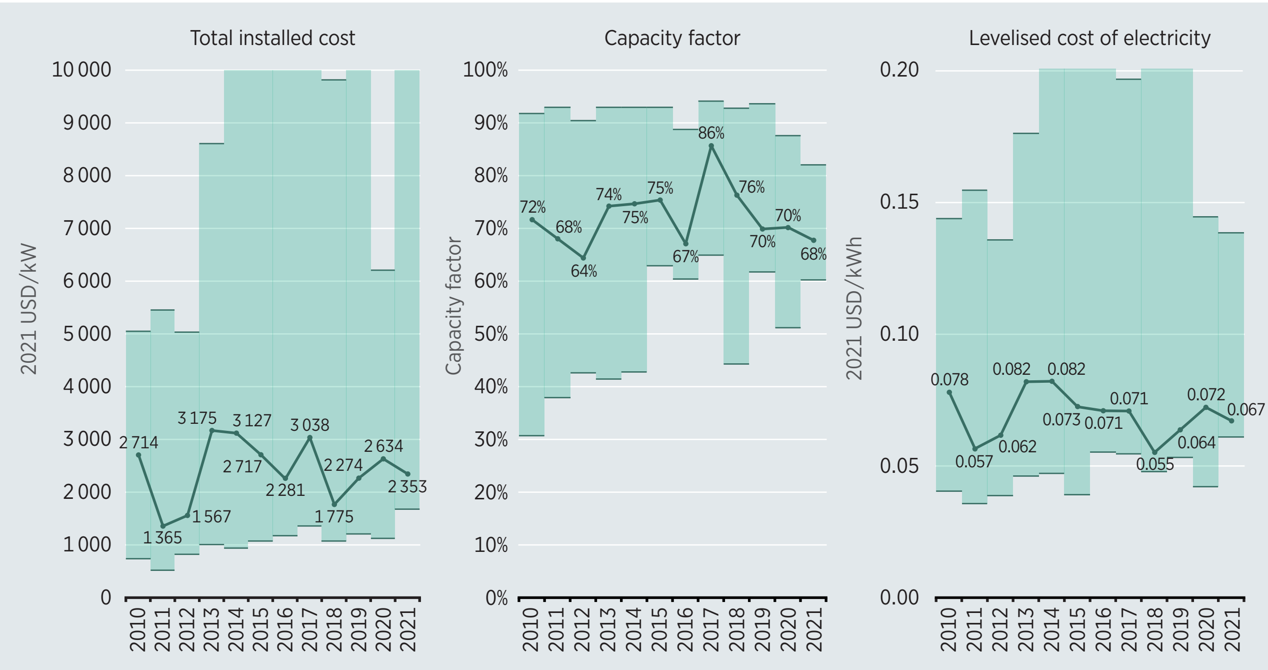
08 BIOENERGY



HIGHLIGHTS

- Between 2010 and 2021, the global weighted average LCOE of bioenergy for power projects fell from USD 0.078/kWh in 2010 to USD 0.067/kWh in 2021. 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 2021, the global weighted average total installed cost was USD 2 353kW (Figure 8.1). This represented a a decrease on the 2020 weighted average of USD 2 634/kW.
- Capacity factors for bioenergy plants are very heterogeneous, depending on technology and feedstock availability. Between 2010 and 2021, the global weighted average capacity factor for bioenergy projects varied between a low of 64% in 2012 to a high of 86% in 2017, decreasing to 68% in 2021.
- In 2021, the weighted average LCOE ranged from a low of USD 0.057/kWh in India and USD 0.060/kWh in China, to highs of USD 0.088/kWh in Europe and USD 0.097/kWh in North America.

Figure 8.1 Global weighted average total installed costs, capacity factors and LCOEs for bioenergy, 2010-2021



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 are different to those 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 2021, 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 2021 period, in China, the 5th and 95th percentile of projects across all feedstocks saw total installed costs range from a low of USD 656/kW for rice husk projects to a high of USD 5 497/kW for renewable municipal waste projects. In India, the range was from a low of USD 533/kW for bagasse projects to a high of USD 4 593/kW for landfill gas projects.

The range is higher for projects in Europe and North America. Costs in these two geographies ranged from USD 619/kW for landfill gas projects in North America, to a high of USD 7 694/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.

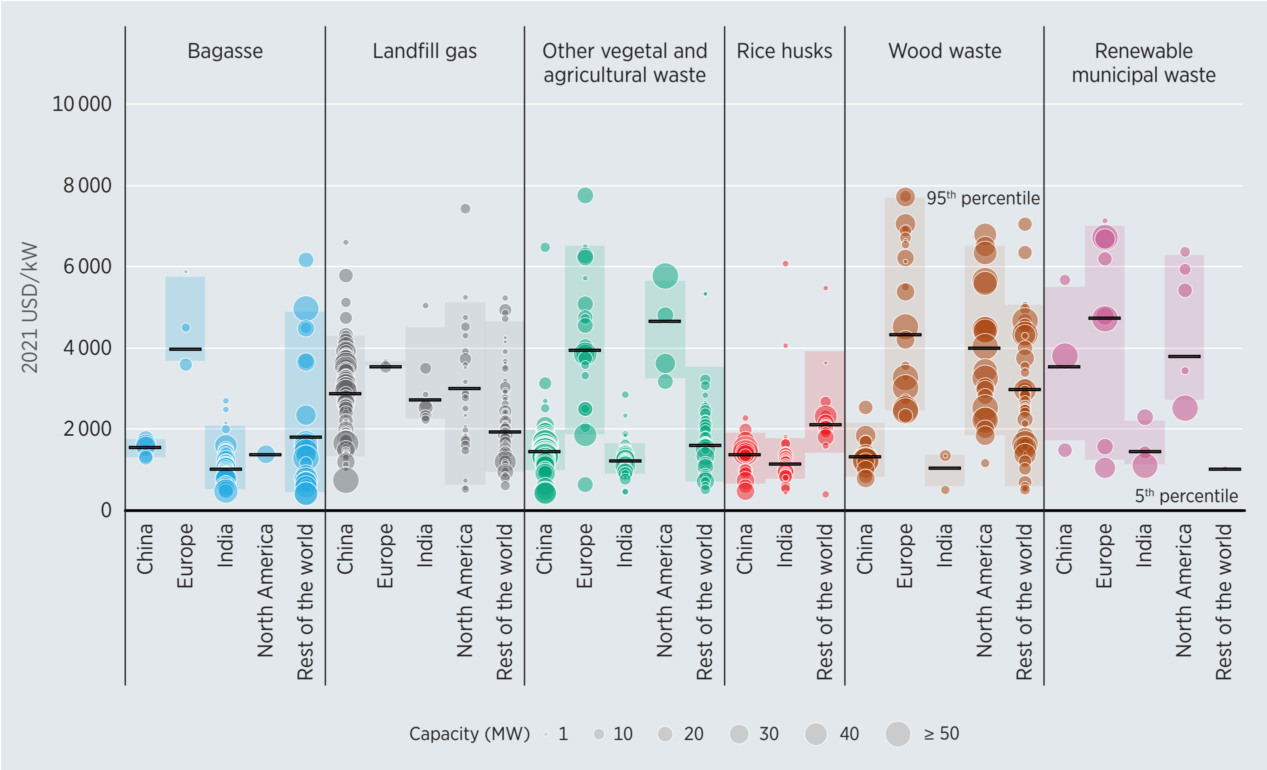
The data available by feedstock for the rest of the world were more limited, but the 5th and 95th percentile total installed cost range for wood waste projects was the widest. For these, the data stretched from USD 600/kW to USD 5 062/kW.[57] The weighted average total installed cost for projects in 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.

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.

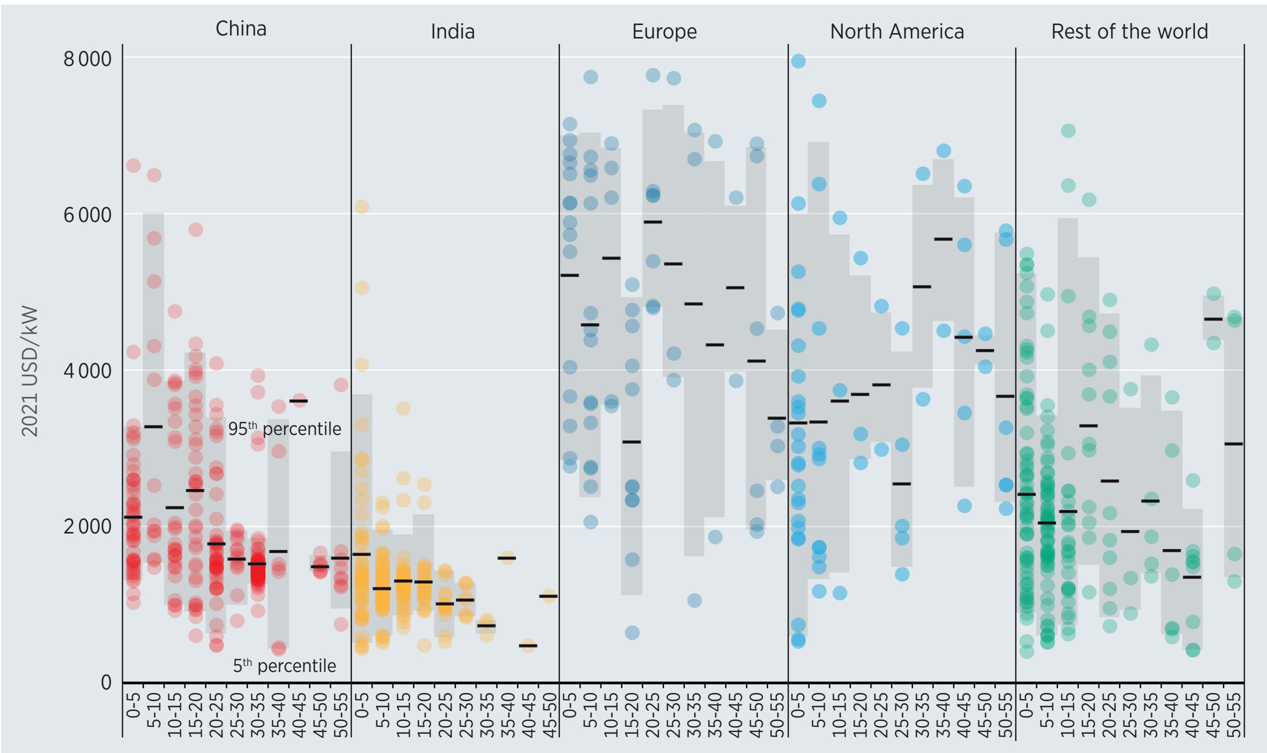
[57] *Excluding the total installed costs for renewable municipal waste, which are not representative given that there are only two projects in the database.*

Figure 8.2 Total installed costs of bioenergy power generation projects by selected feedstocks and country/region, 2000-2021



Source: IRENA Renewable Cost Database.

Figure 8.3 Total installed costs of bioenergy power generation projects for different capacity ranges by country/region, 2000-2021



Source: IRENA Renewable Cost Database.

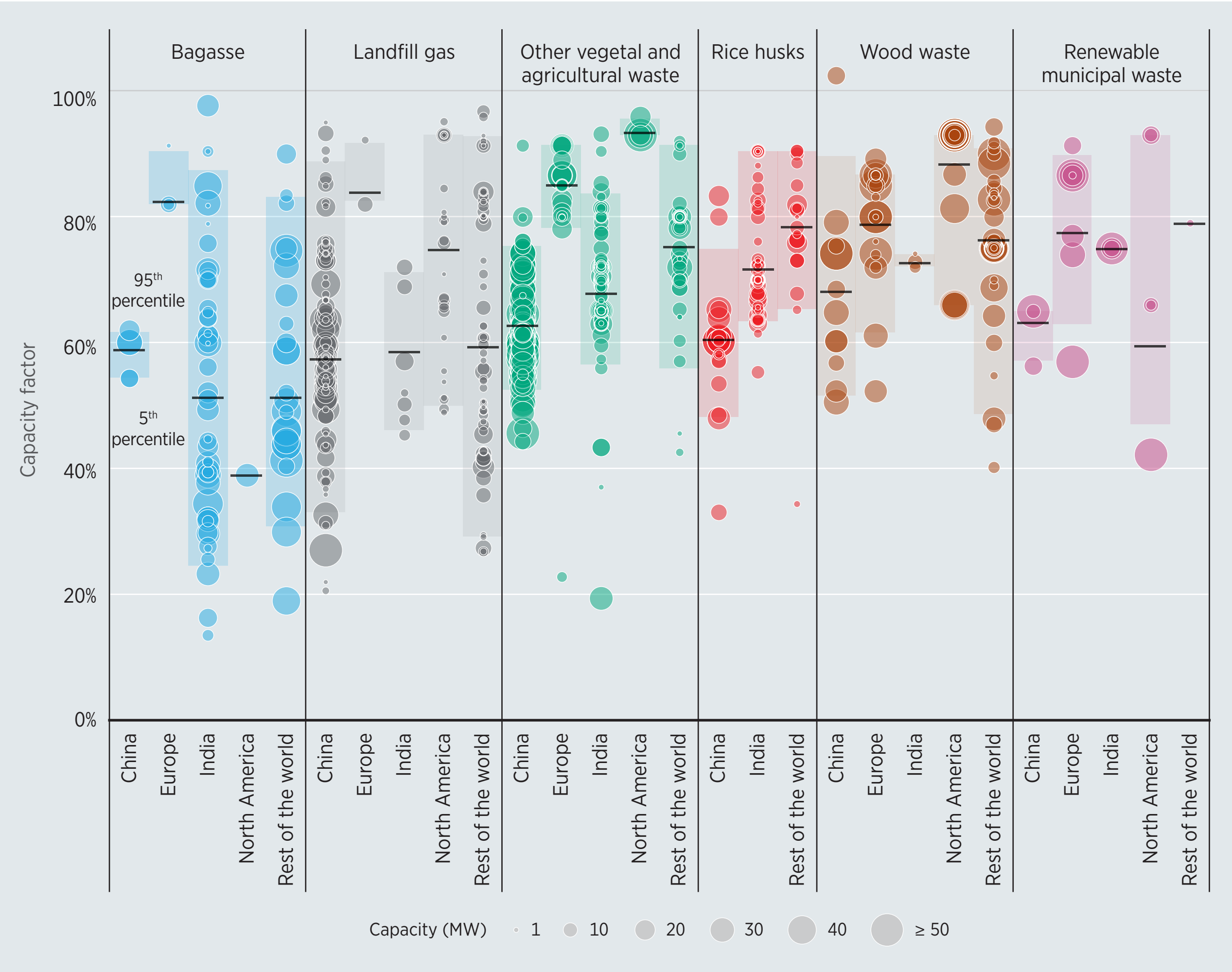
CAPACITY FACTORS AND EFFICIENCY

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, 2000-2021



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 sub-optimal 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 2021. 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, 2000-2021

	2000-2021		
	5th percentile (%)	Weighted average (%)	95th percentile (%)
China	39	**64**	82
Europe	49	**82**	92
India	32	**68**	87
North America	43	**85**	94
Rest of the world	35	**67**	92

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 8.6 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 2021 was USD 0.067/kWh. This was a decrease from USD 0.072/kWh in 2020.

Looking at the full dataset for the period from 2000 to 2021, the lowest weighted average LCOE of biomass-fired electricity generation was found in India, where it stood at USD 0.058/kWh. In addition, India's 5th and 95th percentile values were USD 0.039/kWh and USD 0.104/kWh (Figure 8.6). The highest weighted average for this period was the USD 0.097/kWh recorded in North America, where the 5th and 95th percentiles of projects fell between USD 0.048/kWh and USD 0.183/kWh.

The weighted average LCOE of bioenergy projects in China was USD 0.060/kWh, with the 5th and 95th percentiles of projects falling between USD 0.045/kWh and USD 0.118/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 0.040/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. 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.

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, 2000-2021

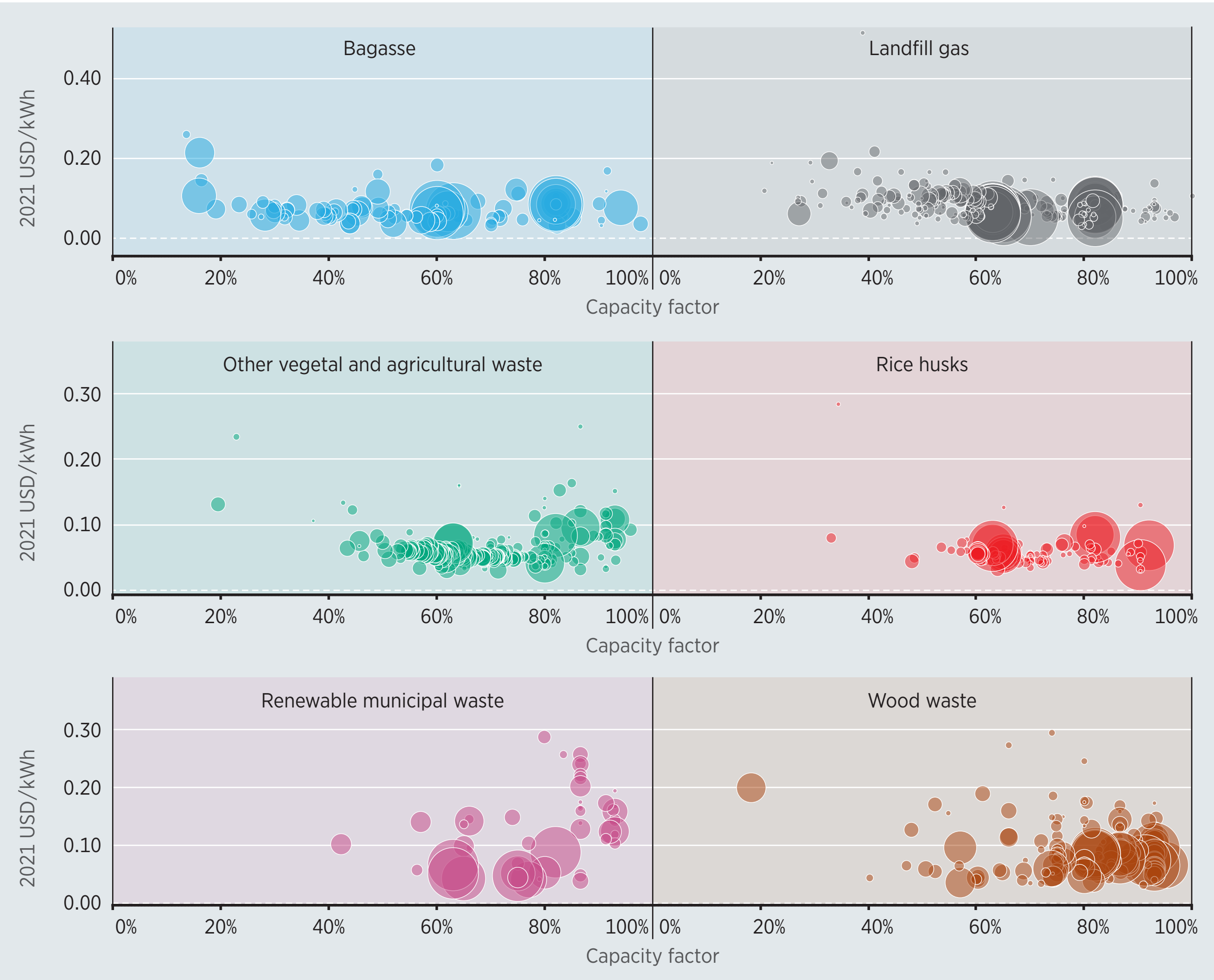
Source: IRENA Renewable Cost Database.

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 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, 2000-2021



Source: IRENA Renewable Cost Database.

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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; and
- 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, 2021 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.

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. In the previous edition of the report, the WACC assumptions had been reduced to reflect more recent market conditions. Consequently, the previous edition of the report assumed a WACC of 7.5% in 2010 for the OECD and China, declining to 5% in 2020. For the rest of world, the previous edition assumed a WACC of 10% 2010, falling to 7.5% in 2020.

For this edition, WACC assumptions are technology- and country-specific benchmark values for 100 countries from IRENAs WACC benchmark tool. It has been calibrated to the results of the IRENA, IEA Wind Task 26 and ETH Zurich cost of finance survey. This exercise results in technology-specific WACC data for *onshore wind, offshore wind and solar photovoltaic* technologies in 100 countries. This data can be found in the dataset accompanying this report (visit irena.org for more details). For countries outside the 100 in the benchmark tool and for bioenergy, geothermal and hydropower, simpler assumptions on the real cost of capital of are made for the Organisation of Economic Co-operation and Development (OECD) countries and China, and the rest of the world, separately. These are in line with the assumptions in the previous edition of this report (Table A1.1).

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		

IRENA has substantially improved the granularity and/or representation of the WACC and O&M costs that are utilised in the LCOE calculation. The changes are designed to improve the accuracy of the LCOE estimates by technology. However, challenges remain in obtaining accurate and up-to-date WACC assumptions given 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.

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

This section discusses in more detail the background to the WACC benchmark model and the process behind the IRENA, IEA Wind and ETH Zurich survey of financing conditions for solar and wind technologies. 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 obtaining 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 long-term goal is to develop a survey methodology which can be repeated periodically in the future.

The first goal of this work, namely to arrive at detailed country and technology-specific WACC data for solar PV, onshore and offshore wind has already been implemented in this edition of the report. This has been achieved by a three-pronged approach to data collection. The basis for it are the following:

- **Desktop analysis**: This combines 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. The 'becnhmark tool' is designed to generate annual country- and technology-specific WACC data based on updated input assumptions on an annual basis for this report.

- **An online expert elicitation survey**: Undertaken by IRENA, IEA Wind Task 26 and ETH Zurich in Q2 and Q3 2021. This was Distributed widely to knowledgeable finance professionals with a detailed understanding of the financing conditions and asked stakeholders with experience of financing renewable projects about the individual components that contribute to the WACC.

- **In-depth, semi-structured interviews**: Targeting a small number of finance professionals involved in the financing of renewable projects to collect data about the cost of debt and equity and the share of debt in the total, as well as on the contextual factors that have been driving these financing costs – or differences in costs – across markets and technologies. These were conducted in Q3 and Q4 2021 and were designed to extract deeper insights about what is driving the differences in financing conditions for technologies in different countries.

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

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The desktop analysis aiming to derive benchmark WACC components (*e.g.* debt cost, equity cost, debt-to-equity ratio, etc.) served as a precursor to the online survey and the semi-structured interviews. The benchmarking process was also a 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.[58] In addition to using the benchmark values created in this process to seed the online survey, the survey process itself helped 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.

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 benchmark also takes the cost of debt as 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[59]) 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.

[58] *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.*

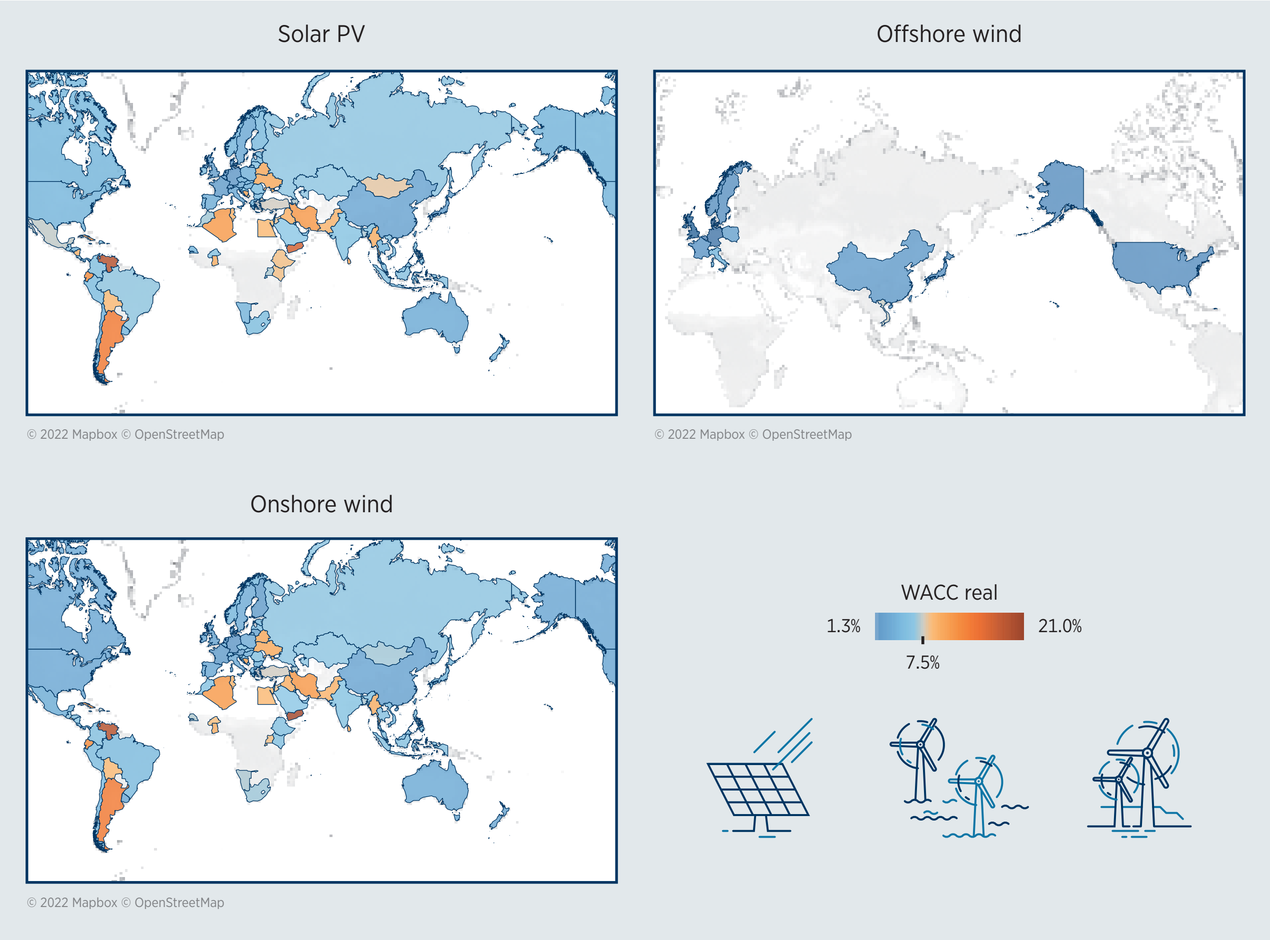
[59] *This is based on work by Prof. A. Damodaran, the methodology used is described at https://papers.ssrn.com/sol3/papers. cfm?abstract_id=3653512*

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.

The project team developed and refined the benchmark tool in the second half of 2021 and Q1 2022. IRENA took the survey results and then used these to refine the benchmark model. This was done so that margins for different financing cost components for individual countries/technologies were as close as possible to the surveyed results.

Figure B1.1 presents the results of the calibrated benchmark tool, for the real after-tax WACC values by country/technology. The centre of the colour scale is 7.5%, so allowing the easy identification of countries that this year that have a higher cost of capital than was assumed in last year's report (IRENA, 2021). In most, but not all, OECD countries, however, the real after-tax WACC is lower than in last year's report – in some cases, substantially. The values used for the LCOE calculations for deployment in 2021 are those in Figure A1.1, with values in 2010 of 7.5% for the OECD and China, and 10% elsewhere. Values between these two dates are linearly interpolated. For those countries not covered by the benchmark too, as already noted, the real after-tax WACC values decline linearly from 2010 to 5% for the OECD and China and 7.5% elsewhere in 2021.

Figure A1.1 Country and technology-specific real after-tax WACC assumptions for 2021



Source: IRENA, based on IRENA, IEA Wind Task 26 and ETH Zurich, 2022 (forthcoming).

For onshore wind, in the absence of project specific cost data, IRENA has used secondary sources for O&M cost assumptions. In many cases, all that was available were costs per kilowatt hour (kWh), while the year of collection or applicability was often not clear. With rising capacity factors for onshore wind, assuming a fixed per kWh figure was, in all likelihood, in some cases overstating the actual contribution of O&M to overall LCOE costs. For this year's report, IRENA has shifted all O&M assumptions to a USD/kW/year basis. Data comes from the IRENA Renewable Costs Database, IEA Wind Task 26, regulatory filings and investor presentations, as well as country-specific research. Where country data is not available through these primary sources, assumptions from secondary sources are used. If no robust country-specific data can be found, regional averages are used. The availability of verified O&M cost remains relatively poor compared to data for project-specific total installed cost and capacity factor.

These changes have improved the representativeness of the LCOE calculations at a country level, and in the case of the WACC assumptions, have also brought our assumptions into line with the results of the IRENA, IEA Wind Task 26 and ETH Zurich cost of finance survey. The resulting changes provide yet step forward in ensuring the most accurate estimation possible of the lifetime cost of renewable power generation costs by country. There is still room for improvement, however, and IRENA is always working to improve its data.

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).

Complete country and technology-specific O&M assumptions by year all technologies can be found in the accompanying dataset to this report.

Onshore wind

For onshore wind, in the absence of project specific cost data, IRENA has used secondary sources for O&M cost assumptions. In many cases all that was available were costs per kWh and the year of collection or applicability was often not clear. With rising capacity factors for onshore wind, assuming a fixed per kWh figure was, in all likelihood, overstating the actual contribution of O&M to overall LCOE costs in some cases. For this year's report, IRENA has shifted all O&M assumptions to a USD/kW basis. Data comes from the IRENA Renewable Costs Database, IEA Wind Task 26, regulatory filings, investor presentations, as well as country-specific research. Where country data is not available through these primary sources, assumptions from secondary sources are used. If no robust country-specific data can be found, regional averages are used. This characterisation has improved the accuracy of the LCOE calculations, particularly for a number of non-OECD countries where capacity factors have increased significantly over the last 11 years.

Table A1.2 O&M cost assumptions for the LCOE calculation of onshore wind projects

2021 USD/kW/year	2021
Sweden	38
Ireland	32
Germany	44
Denmark	32
United States	38
Norway	37
Japan	83
Brazil	27
Canada	35
Mexico	44
Spain	26
United Kingdom	37
France	47
China	26
India	21
Australia	34
Other OECD	36
Other non-OECD	31

Source: IRENA Renewable Cost Database.

Offshore wind

The O&M cost assumptions have also been aligned to a single USD/kW/year metric.

Table A1.3 O&M cost assumptions for the LCOE calculation of onshore wind projects

2021 USD/kW/year	2021
Belgium	76
Denmark	69
Netherlands	80
Germany	77
United Kingdom	74
France	80
China	52
United States	70
Japan	127
Other OECD	75
Other non-OECD	62

Source: IRENA Renewable Cost Database.

Solar PV

The O&M cost assumptions for solar PV can be found below:

Table A1.4 O&M cost assumptions for the LCOE calculation of PV projects

Year	OECD 2021 USD/kW/year	Non-OECD 2021 USD/kW/year
2010	27.1	25.6
2011	24.0	23.5
2012	23.4	18.2
2013	22.9	15.3
2014	22.4	13.7
2015	21.7	12.4
2016	21.1	11.3
2017	21.5	10.9
2018	20.1	10.4
2019	19.2	9.9
2020	18.2	9.6
2021	18.2	9.6

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.[60] 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.[61]

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.

[60] 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.

[61] 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 A1.5 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 · 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 · All material necessary for mounting the inverter and all type of combiner boxes
Safety and security	· Fences · Camera and security system · All equipment fixed installed as theft and/or fire protection
Grid connection	· All medium voltage cables and connectors · Switch gears and control boards · Transformers and/or transformer stations · Substation and housing · Meter(s)
Monitoring and control	· Monitoring system · Meteorological system (*e.g.* irradiation and temperature sensor) · Supervisory control and data system
Installation	
Mechanical installation (construction)	· Access and internal roads · Preparation for cable routing (*e.g.* cable trench, cable trunking system) · Installation of mounting/racking system · Installation of solar modules and inverters · Installation of grid connection components · Uploading and transport of components/equipment
Electrical installation	· DC installation (module interconnection and DC cabling) · AC medium voltage installation · Installation of monitoring and control system · Electrical tests (*e.g.* DC string measurement)
Inspection (construction supervision)	· Construction supervision · 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 · All costs related to environmental regulations
System design	· Costs for geological surveys or structural analysis · Costs for surveyors · Costs for conceptual and detailed design · Costs for preparation of documentation
Customer acquisition	· Costs for project rights, if any · 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

Natural gas and coal prices and fuel-only generating costs in 2022

The analysis in Chapter 1 for figures 1.15 to 1.18, 1.20 and 1.21 is based on actual natural gas and coal prices for January to April/May 2022. In some cases, this is based on daily pricing data and for other markets on monthly average values. The historical price data is sourced from a mixture of sources, including *ex-ante* price exchange data or futures contracts, energy regulators data monitoring services, government import data and market intelligence or other research that have disclosed price data.[62]

Assumptions for the period May/June to December 2022 are taken from industry consensus in mid-May to mid-June depending on the market, futures prices for coming months, forward contracted price data, or estimates of likely 2022 out turns based on known contractual arrangements. Table A1.2 provides the data sources for the countries analysed in Figure 1.16

Table A1.6 Fossil fuel price assumptions and sources by country for 2022

	Fuel	Price for 2022 (2021 USD/MWh)	Cost as generated (2021 USD/MWh)	Period of historical data (2022)	Historical data source	Future data sources
Argentina	Fossil gas	42	92			Blended LNG/ Bolivian import cost
Australia	Fossil gas					
Brazil	Fossil gas	103	224	Jan-Apr	Import data	LNG futures
Chile	Fossil gas	37	79	Jan-Apr	Import data	Pipeline import cost (Argentina)
China	Fossil gas	99	198	Jan-May	JKM gas pricing	Forward LNG contracts
	Coal	33	77	Jan-May	Domestic pricing + Newcastle (5500 kcal) pricing	China coal price band advice + Newcastle coal price futures
Denmark	Fossil gas	116	204	Jan-May	Dutch TTF	Forward month Dutch TTF pricing
Europe (generic)	Fossil gas	110	229	Jan-May	Dutch TTF	Forward month Dutch TTF pricing
Finland	Fossil gas/ coal	82	208	Jan-May	Dutch TTF	Forward month Dutch TTF pricing
France	Fossil gas	110	245	Jan-May	Dutch TTF	Forward month Dutch TTF pricing
Germany	Fossil gas	110	268	Jan-May	Dutch TTF	Forward month Dutch TTF pricing
India	Fossil gas	60	149	Jan-Apr	Import data	Convergence with Australian net-back LNG pricing
	Coal	38	121	Jan-Mar	Import data	Newcastle coal price futures

[62] *For this final category, every effort has been taken to ensure the values are representative, but ultimately, this data should be treated with more caution than the other sources.*

	Fuel	Price for 2022 (2021 USD/MWh)	Cost as generated (2021 USD/MWh)	Period of historical data (2022)	Historical data source	Future data sources
Italy	Fossil gas	117	259	Jan-Apr	Day-ahead gas price (MGP)	Forward month Dutch TTF pricing
Japan	Fossil gas	100	211	Jan-Apr	JKM gas pricing	Forward LNG contracts
Republic of Korea	Fossil gas	99	180	Jan-Apr	JKM gas pricing	Forward LNG contracts
Mexico	Fossil gas	27	52	Jan-Feb	U.S. export data	EIA Short term Outlook (adjust-ed)
Türkiye	Fossil gas	70	128	Jan-Apr	BOTAŞ	Linked to Dutch TTF forward month pricing
Viet Nam	Coal	44	126	Jan-Mar	Import data	Newcastle coal price futures
United Kingdom	Fossil gas	93	211	Jan-May	UK NBP	UK NBP forward month pricing
United States	Fossil gas	24	54	Jan-May	Henry Hub (NYMEX)	EIA Short-term Energy Outlook, April 2022

The analysis was finalised by country between the end of May 2022 and early June 2022 in most cases. Given the volatile and fast moving situation, the outlook for 2022 may have changed between the finalisation of the analysis for expected prices for 2022 and when this report is published. This is likely to have most impact on countries which to date have managed to see lower average costs in the period January to April/May 2022, but where prices start to align (or jump) more closely to match traded LNG prices.

In Table A1.2, 'import data' refers to official government trade statistics. EU countries include USD 90/tonne of CO_2 EU ETS price in the generated price, the fuel price excludes this to allow a direct comparison across markets. Denmark's gas-fired generation includes a credit for the heat generation as all gas-fired generation includes heat recovery. All other countries the analysis is exclusively for power generation only plants. Forward month Dutch TTF pricing was based on rates offered on 6 May, variations from those values should be factored into the interpretation of the estimated average 2022 values. Forward LNG contracts are based on declared LNG contract pricing (ACCC, 2022) and are a sample that may be representative for different markets and months in Asia-Pacific countries. For Mexico, data is based on U.S. pipeline export data from the Energy Information Administration.[63] Newcastle coal prices are assumed to moderate relative to value in May 2022 and average USD 300/tonne for the second half of 2022, with an undeniable upside risk.

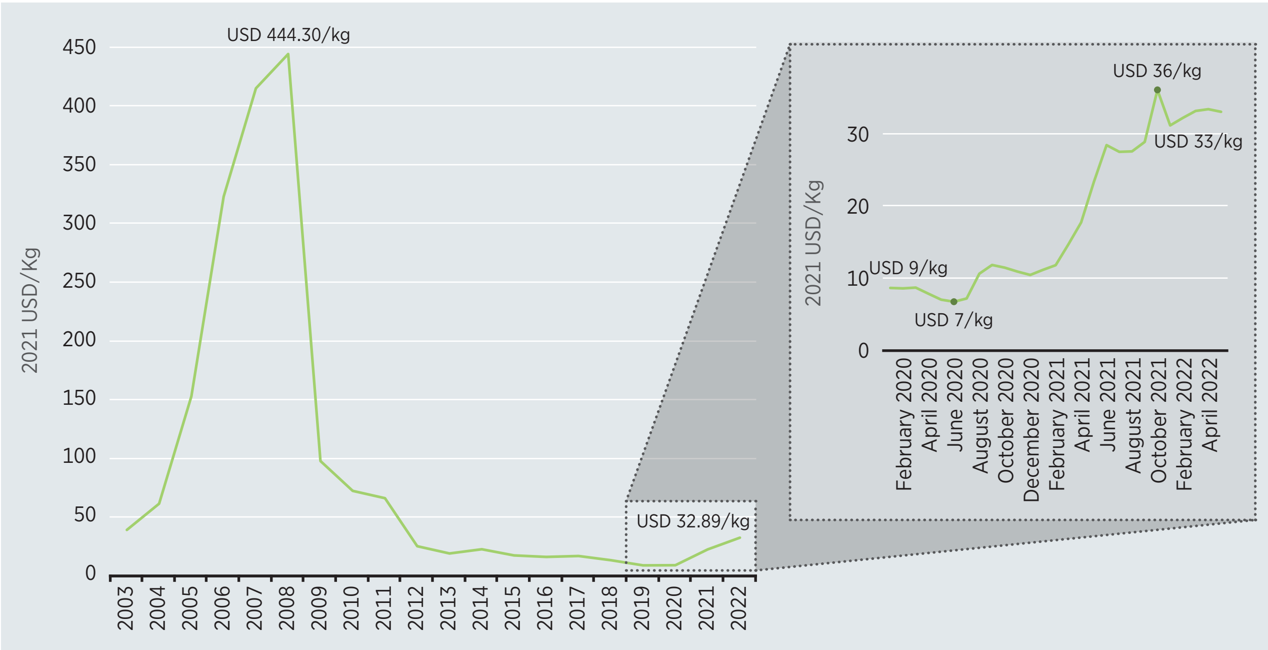
[63] See *www.eia.gov/dnav/ng/ng_move_poe2_dcu_nus-nmx_m.htm*

Average generation efficiency for gas and coal-fired power plants is taken from *International comparison of fossil power efficiency and CO_2 intensity - Update 2018* (Ecofys, 2018) or from national energy balance data, where this does not yield realistic assumptions IRENA has estimated fleet efficiency based on turbine type and capacity from S&P Global Market Intelligence's *World Electric Power Plant Data Base (WEPP)* (S&P Global Market Intelligence, 2022).

Polysilicon cost increases for solar PV modules, 2019 to 2022

One of the major drivers of solar PV module cost increases in 2021 and 2022 were rising polysilicon prices. Polysilicon prices increased from USD 9/kilogramme (kg) in Q1 2020 to an average of around USD 33/kg between January and May 2022 (Bernreuter, 2022; PV Infolink, 2021 and Energy Trend, 2021). Although polysilicon usage per watt is falling due to improved wafer sawing technologies, reduced kerf loss and thinner wafers (IRENA, 2022b), the order of magnitude of the polysilicon price increase has seen prices return to levels not seen since 2011. Expectations are that polysilicon prices will remain at or around current levels for the rest of 2022, before additional capacity starts to return prices to more normal levels in 2023.

Figure A1.2 Solar PV grade polysilicon prices, 2003-2022



Sources: Bernreuter, 2022; PV Infolink, 2021 and Energy Trend, 2021.
Note: The left-hand side includes annual data, while the right-hand side shows monthly averages for January 2020 to May 2022.

Solar PV cell architecture is constantly evolving and improvements in performance are a constant factor in the market. In addition, continuous efforts are being made to improve manufacturing processes in order to reduce material and production costs. IRENA has examined the latest trends in solar PV cell and technology innovation, manufacturing improvements and their impact on the intensity of silver and polysilicon use in solar PV. We have also looked at what metrics can be used to track technology progress in addition to cost and performance metrics (IRENA, 2002c).

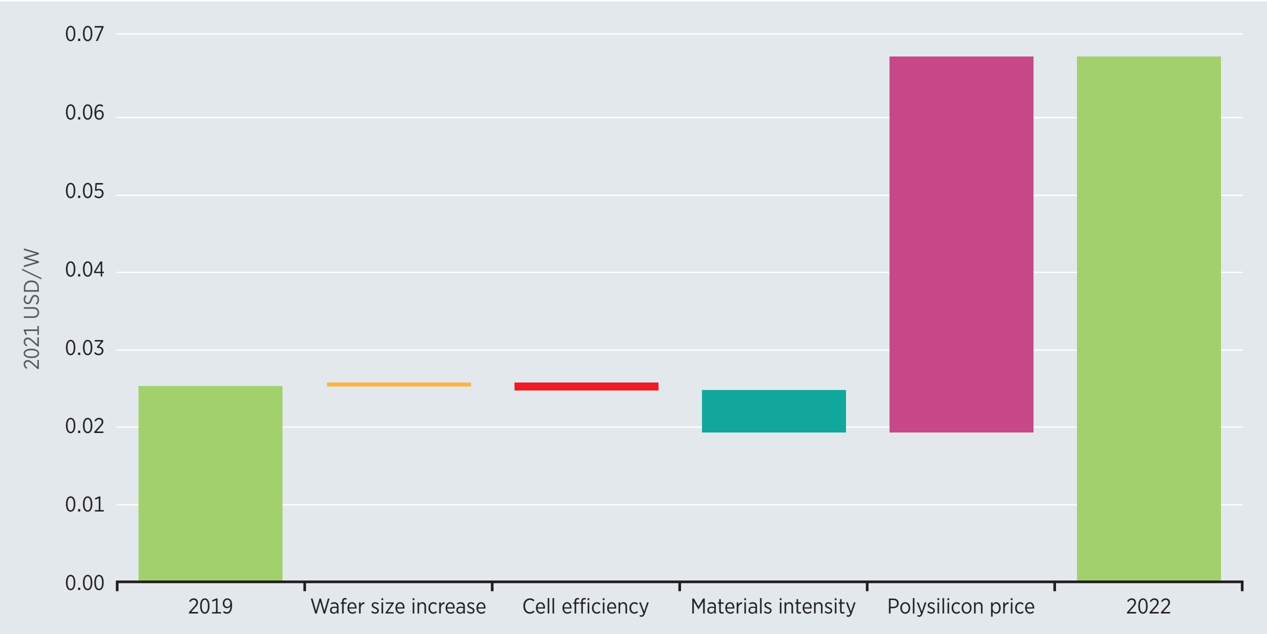
Before discussing the impact of polysilicon price increases on solar PV cell costs, it is useful to highlight some of the key recent solar PV cell trends. One of these is that mono-crystalline silicon passivated emitter and rear cell (p-type junction [PERC]) cells have come to dominate the market. Bifacial cells, that can generate electricity from light hitting the front and rear of the panels, have also reached a 50% market share, with this likely to increase in the coming years (ITRPV, 2022). There have also been a number of other innovations impacting polysilicon usage per watt, in addition to those that have already been mentioned. These include the trend to larger cell sizes that are slightly more silicon intensive, and an increase in average cell and module efficiency (IRENA, 2022b).

Given relatively stable prices until recently, the key factors in polysilicon-related costs have been those related to improvements in manufacturing techniques (*e.g.* improved pulling of longer ingots, diamond wire sawing and thinner wafers) and improved cell efficiency. The latter has reduced material usage per watt, as a given surface area now has a higher power rating.

Yet, the polysilicon price increases of 2021 have more than outweighed the steady, deflationary contribution these factors have made over the past three years. Figure 1.10 decomposes the drivers of the cost per watt of polysilicon in solar PV cells between 2019 and 2022. The main cost reduction drivers between those years were manufacturing and technology improvements that reduced polysilicon use in solar PV cells, reducing costs per watt by 22%. Improvements in cell efficiency also contributed, but by a more modest percentage.

These decreases were more than offset, however, by the 250% increase in polysilicon prices over the period 2019 to 2022 As a result, the indicative cost per watt for solar PV cells rose from USD 0.025/W in 2019 to USD 0.068/W in Q1 2022. This is an increase of USD 0.043/W over the period. Yet, because of improvements in material intensity and the efficiency of solar cells, this is less than IRENA's estimate of the underlying increase for polysilicon over the period 2019 to 2022, which was USD 0.048/W.

Figure A1.3 Decomposing the impact of different drivers on polysilicon costs in solar PV cells, 2019-2022



Source: IRENA analysis based on IRENA, 2022b; ITRPV, 2022; Bernreuter, 2022; PV Infolink, 2021; and Energy Trend, 2021.

Impact of materials, energy and transport inflation on onshore wind turbine costs

IRENA and the University of Cork examined the cost components for onshore wind turbines between 2008 and 2017 to understand the underlying drivers of cost reductions in wind turbines (Elia, A., *et al.,* 2020). This examination included an assessment of the materials cost and intensity and how these had changed over time. The analysis drew on a range of sources, but for the materials analysis it relied predominantly on life cycle analysis information periodically published by Vestas for their different turbine types.[64] This analysis is representative of markets outside China and India, as these two countries have very different cost structures and would require a separate analysis. In the case of China, for example, wind turbine prices actually fell in 2021, as developers pressed manufacturers to lower prices in the face of the end of subsidy support.

IRENA has updated this wind turbine cost driver analysis with the latest input data for materials use and prices, as well as the other input variables for 2020 and 2021. Data for those two years are, of course, marked by the impact of the pandemic, when a combination of lower materials costs in 2020 where replaced by supply chain and COVID-19 related business interruptions as time wore on. As a result, some benchmark values in the analysis of turbine price compositions have been quite volatile, in comparison to earlier years. This is particularly true for profit margins, where one-off negative factors related to COVID-19 in 2020 were not as prevalent in 2021, but replaced by rapidly increasing commodity costs as global demand for goods and services rebounded.

The analysis for materials intensity and costs was more robust, as the input assumptions were more easily sourced and more easily interpreted than financial data for turbine manufacturers.

The analysis shows that between 2008 and 2017, the representative wind turbine price fell by 47%. Materials costs fell by 28% over the same period, accounting for slightly less than 10% of the total cost reduction (Figure 1.12). The shift to larger turbine sizes by MW actually increased turbine materials intensity per kW for steel in the towers and concrete in the foundations, as these grew proportionately more than the MW increase (predominantly due to higher towers and increased loads on the towers from heavier turbines). From 2007 to 2017, however, the cost for turbine materials fell by more than the increase in materials intensity. Over that period, there was only a small, 5% decline in materials costs per kW, with other factors – notably, reduced margins – contributing most of the 21% overall fall in wind turbine prices per kW.

The year 2021 was marked by the impact of supply chain disruptions and increases in transportation and materials costs. That year, IRENA has estimated higher materials prices contributed to a USD 145/kW increase in materials costs for the wind turbine. This was 65% up on the materials costs in 2020, which was a year marked by low commodity prices.

[64] *The analysis needs to be considered within the context that detailed bottom-up data required for a cost breakdown analysis at a global scale is not readily available. Data for materials intensity, distribution costs, margins, depreciation etc. are not universally available for all, or even most, market players. The analysis, although normalised to total market costs, therefore relies on a narrower subset of market data for the cost breakdown. See Elia, et al., 2020 for a detailed description of the methodology, results and data limitations that need to be considered when interpreting the results.*

International Monetary Fund (IMF) expectations are that commodity prices will remain elevated in 2022 (IMF, 2022a) and although there is significant uncertainty, this analysis has therefore assumed prices will remain elevated for the rest of the year, at or near their recent maximums. Copper prices are therefore assumed to be around 53% higher in 2022 than in 2020, steel prices 120% to 170% higher, aluminium prices 67% higher, polymers and ceramics 60% to 80% higher, and concrete prices around 20% higher. It is important to note that the analysis for 2022 presented here relies on updated materials price data for the period January to April, or in some cases for May as well. It should be noted, too, that for many of these materials costs, most of the price increase occurred over the period from June 2020 to the end of 2021. For instance, taking Germany as an example, around four-fifths of the roughly 120% steel product price rise between June 2020 and April 2022 occurred in 2020 and 2021.

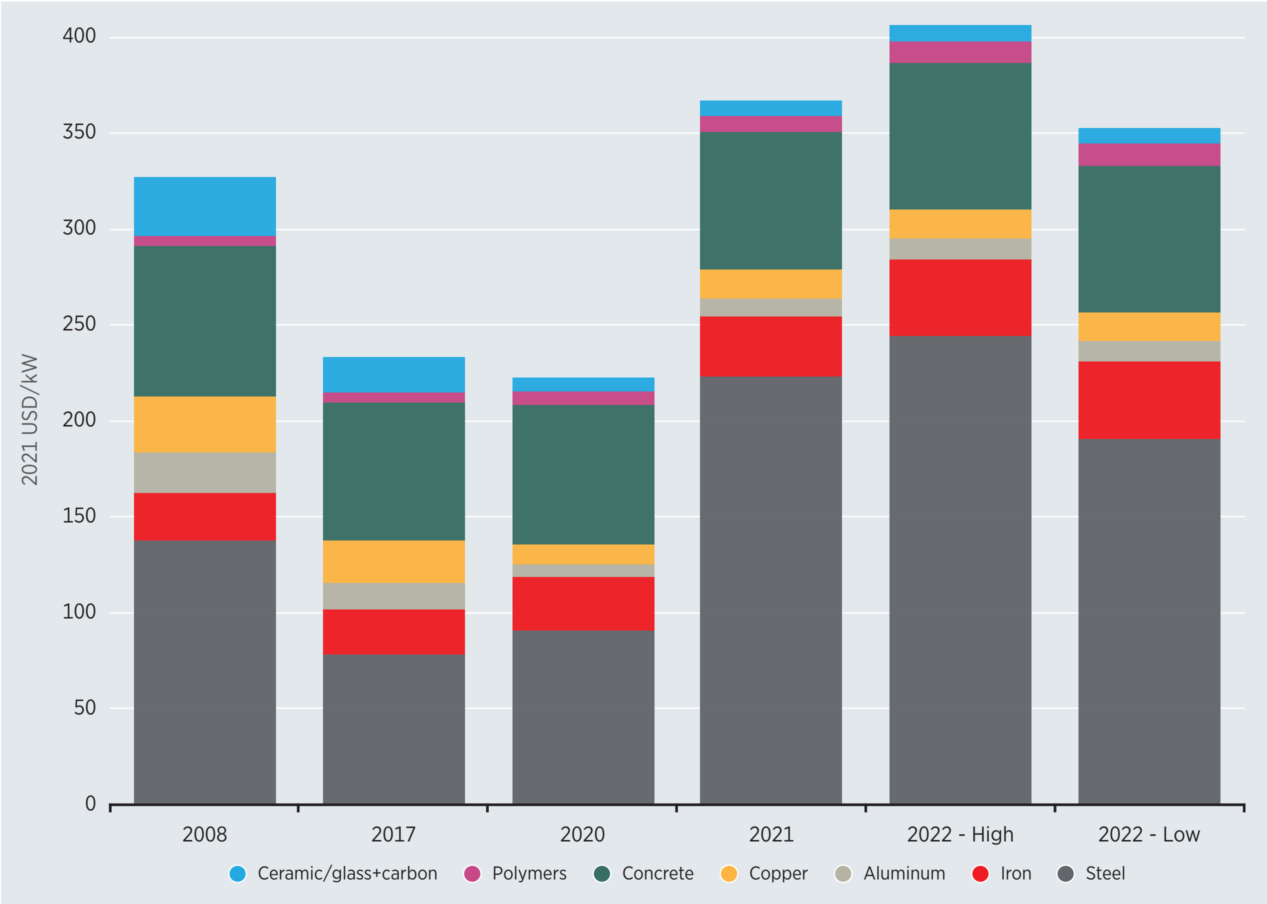
The result for 2022 should not be seen as a prediction of what the impact on wind turbine prices might be this year. The 2022 analysis is designed to help understand to what extent the recent material price increases were passed through in turbine prices in 2021, and how much more materials inflation might be to come in 2022, with everything else held constant

Given wind turbine prices in 2021 were on average USD 73/kW higher than in 2020, only around half of the USD 145/kW increase in materials prices between 2020 and 2021 appears to have been passed through to date

Looking specifically at the increase in materials costs by year (Figure A1.4) over 2020, the analysis suggests wind turbine prices might have to increase by between USD 130/kW and USD 185/kW if materials costs are to be fully passed through.

Given wind turbine prices in 2021 were on average USD 73/kW higher than in 2020, only around half of the USD 145/kW increase in materials prices between 2020 and 2021 therefore appears to have been passed through already. If margins were to be maintained across all non-materials categories, this suggests an additional increase in 2022 by around USD 60/kW and USD 110/kW would be required. Such an increase in costs would represent a rise of between 4% and 8% in the weighted average total installed cost of onshore wind, excluding China and India, over 2021 values. Much would depend, however, on the extent to which 2021's wind turbine price increases were captured in the projects commissioned that year, with a larger increase possible in some markets.[66] Additionally, individual markets would experience different outcomes around this average, with the most competitive markets likely to see the largest percentage increases in costs, given their lower overall total installed cost structure.

Figure A1.4 Representative wind turbine materials costs by major material, 2008, 2017, 2020, 2021 and 2022



Source: IRENA analysis based on Elia, A., et al., 2020.

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 (839 GW), the United States (226 GW), India (140 GW), and Germany (150 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

After these four major countries, Brazil and Germany both are represented by 88 GW of projects, Spain by 43 GW, the United Kingdom by 42 GW, Viet Nam and Japan are represented by 40 GW of projects, Italy by 34 GW, Canada by 30 GW and Australia and Türkiye both by 29 GW of projects.

Onshore wind is the largest single renewable energy technology represented in the IRENA Renewable Cost Database, with 806 GW of project data available from 1983 onwards. Solar photovoltaic is the second largest technology represented in the database with 582 GW of projects, followed by hydropower with 551 GW of projects since 1961, with around 90% of those projects commissioned in the year 2000 or later. Cost data is available for 61 GW of commissioned offshore wind projects, 84 GW of biomass for power projects, 8 GW of geothermal projects and around 8 GW of CSP projects.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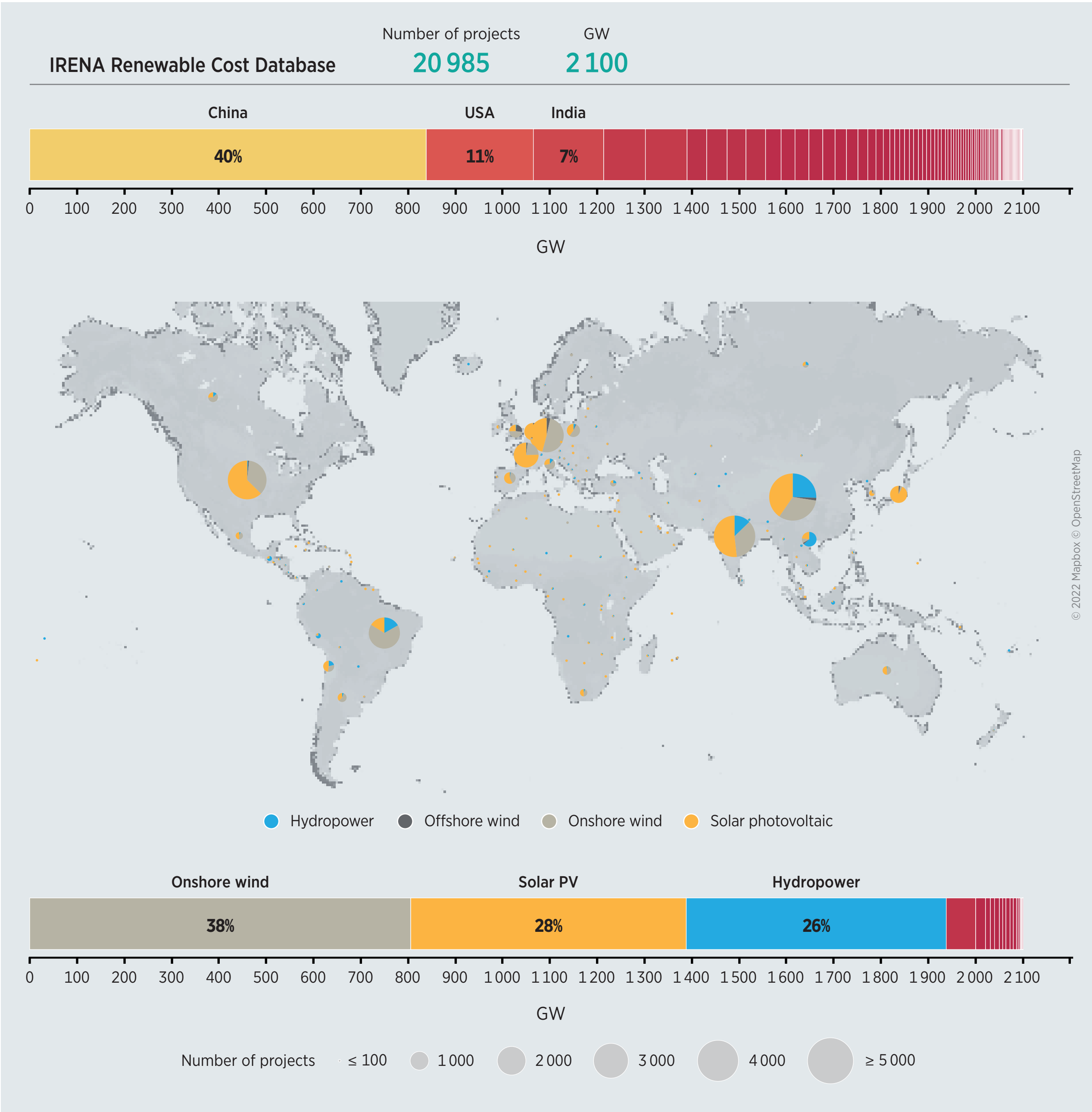
The coverage of the IRENA Renewable Cost Database is more or less complete for offshore wind and CSP, where the relatively small number of projects can be more easily tracked. The database for onshore wind and hydropower is representative from around 2007, with comprehensive data from around 2009 onwards. 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.

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



Disclaimer: This map is for illustration purposes only. Boundaries and names shown on this map do not imply any official endorsement or acceptance by IRENA.

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, Türkiye.

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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